2022/2023

Integrated Resource Plan

CenterPoint® Energy

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IRP Rule Requirements Cross Reference Table

Rule		Section(s)
170 IAC 4-7-2 Integrated Resource Plan Submission Section 2		
(c) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents:		
(1) The IRP.		2022/2023 IRP submitted on May 26, 2023
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP. The technical appendix shall include at least the following: (A) The utility's energy and demand forecasts and input data used to develop the forecasts. (B) The characteristics and costs per unit of resources examined in the IRP; (C) Input and output files from capacity planning models, in electronic format. (D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file. If a utility does not provide the above information, it shall include a statement in the technical appendix specifying the nature of the information it is omitting and the reason necessitating its omission. The utility may request confidential treatment of the technical appendix under section 2.1 of this rule.		12 Technical Appendix Attachments 1.1-8.2
(3) An IRP summary that communicates core IRP concepts and results to nontechnical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) public advisory process; and (vi) additional details requested by the director. (B) A simplified discussion of the utility's resource types and load characteristics.		Executive Summary (non-technical summary document)
The utility shall make the IRP summary readily accessible on its website.		www.centerpointenergy.com/irp

170 IAC 4-7-2.6 Public advisory process Sec. 2.6		
(b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP within 15 business days of a written request or as otherwise agreed to by the utility and the interested party. If a utility is unable to provide the requested information within 15 business days or the agreed timeframe, it shall provide a statement to the director and the requestor as to the reason it is unable to provide the requested information.		3.3 Stakeholder Input; 12 Technical Appendix Attachment 3.1 Stakeholder Materials
(c) The utility shall solicit, consider and timely respond to relevant input relating to the development of the utility's IRP provided by: (1) interested parties; (2) the OUCC; and (3) commission staff.		3 Public Participation Process
(d) The utility retains full responsibility for the content of its IRP.		n/a
(e) The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three (3) meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following:		3.1 Public Participation Process
(A) An introduction to the IRP and public advisory process. (B) The utility's load forecast. (C) Evaluation of existing resources. (D) Evaluation of supply-side and demand-side resource alternatives, including: (i) associated costs; (ii) quantifiable benefits; and (iii) performance attributes. (E) Modeling methods. (F) Modeling inputs. (G) Treatment of risk and uncertainty. (H) Discussion seeking input on its candidate resource portfolios. (I) The utility's scenarios and sensitivities. (J) Discussion of the utility's preferred resource portfolio and the utility's rationale for its selection.		3 Public Participation Process; 12 Technical Appendix Attachment 3.1 Stakeholder Materials
(2) The utility may hold additional meetings.		3.1 Public Participation Process
(3) The schedule for meetings shall: (A) be determined by the utility; (B) be consistent with its internal IRP development schedule; and (C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.		3 Public Participation Process

	170 IAC 4-7-4 Integrated resource plan contents Sec. 4	
An IRP must include the following: (1) At least a twenty (20) year future period for predicted or forecasted analyses.		4.6 Energy and Demand Forecast (Reference Case)
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.		11.1.3 Overview of Past Forecasts
(3) At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.		Figure 7.8 CEI South Peak Load (MW) Alternative Scenarios
(4) A description of the utility's existing resources in compliance with section 6(a) of this rule.		6.2 Current Resource Mix
(5) A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed.		6 Resource Options; 8 Portfolio Development and Evaluation
(6) A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.		6.2 Current Resource Mix; 6.3 Potential Future Options Modeling Assumptions
(7) The resource screening analysis and resource summary table required by section 7 of this rule.		8.1.3 Portfolio Screening; Figure 11.36 New Construction Alternatives
(8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with section 8(a) and 8(b) of this rule.		8.1 Portfolio Development
(9) A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.		8.2 Evaluation of Portfolio Performance; 9.1 Preferred Portfolio Recommendation
(10) A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.		10 Short Term Action Plan
(11) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.		List of Acronyms/Abbreviations with Definitions; 2 CEI South's IRP Process; 3 Public Participation Process; 4 Customer Energy Needs; 6 Resource Options; 7 Model Inputs and Assumptions; 8 Portfolio Development and Evaluation
(12) Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this rule. If the IRP references a third-party data source, the IRP must include for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date;		12 Technical Appendix Attachments

(E) page number; and (F) an explanation of adjustments made to the data. The data must be submitted within two (2) weeks of submitting the IRP in an editable format, such as a comma separated value or excel spreadsheet file.		
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use. 14) The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.		6.2.4 Energy Efficiency; 11.1.1 Forecast Inputs; 12 Technical Appendix Attachment 4.1 2022/2023 CEI South Long-Term Electric Energy and Demand Forecast Report
(15) A proposed schedule for industrial, commercial and residential customer surveys to obtain data on: (A) end-use penetration; (B) end-use saturation rates; and (C) end-use electricity consumption patterns.		11.1.1.4 Equipment Efficiencies and Market Share Data
(16) A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs and other aspects of planning.		1.3.3.1 Advanced Metering Infrastructure (AMI)
(17) A discussion of the designated contemporary issues designated, if required by section 2.7(e).		1.3.13 Contemporary Issues
(18) A discussion of distributed generation within the service territory and its potential effects on: (A) generation planning; (B) transmission planning; (C) distribution planning; and (D) load forecasting.		4.4 Customer Owned Distributed Energy Resources
(19) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.		4.3 Model Framework; 7.1 Resource Model (EnCompass)
(20) A discussion of how the utility's fuel inventory and procurement planning practices-have been taken into account and influenced the IRP development.		9.1.7 Fuel Inventory and Procurement Planning

(21) A discussion of how the utility's emission allowance inventory and procurement practices for an air emission have been considered and influenced the IRP development.		11.2.1 Air Emissions
(22) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.		8.1 Portfolio Development; 8.1.2 Scenario-Based and Deterministic Portfolios; 8.1.3 Portfolio Screening
(23) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.		1.3.2 Environmental Rules; 7.2. Reference Case Scenario; 7.3 Alternate Scenarios
(24) A discussion of how the utilities' resource planning objectives, such as: (A) cost effectiveness; (B) rate impacts; (C) risks; and (D) uncertainty; were balanced in selecting its preferred resource portfolio.		8.2 Evaluation of Portfolio Performance; 9.1 Preferred Portfolio Recommendation
(25) A description and analysis of the utility's Reference Case scenario, sometimes referred to a business as usual case or reference case. The Reference Case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include: (i) existing federal environmental laws; (ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and (iii) existing policies, such as tax incentives for renewable resources. (C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable. (D) Not include future resources, laws, or policies unless: (i) a utility subject to section 2.6 of this rule solicits stakeholder input regarding the inclusion and describes the input received; (ii) future resources have obtained the necessary regulatory approvals; and		7.2 Reference Case Scenario

(iii) future laws and policies have a high probability of being enacted. A Reference Case scenario need not align with the utility's preferred resource portfolio.		
(26) A description and analysis of alternative scenarios to the Reference Case scenario, including comparison of the alternative scenarios to the Reference Case scenario.		7.3 Alternate Scenarios
(27) A brief description of the models(s), focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC). (C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following: (i) The limits of the utility's transmission use. (ii) The utility's assessment practices developed through experience and study. (iii) Operating restrictions and limitations particular to the utility.		6.4 Transmission Considerations
(28) A list and description of the methods used by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast; (ii) forecasted impact from demand-side programs; (iii) cost estimates; and (iv) analysis of risk and uncertainty.		4.3 Model Framework; 7.1 Resource Model (EnCompass); 6.3.2 DSM, 4.6 Energy and Demand Forecast (Reference Case); 6 Resource Options; 7 Model Inputs and Assumptions; 8.2 Evaluation of Portfolio Performance; 9.1 Preferred Portfolio; 12 Technical Appendix Attachments 1.1, 4.1, 6.2, and 8.2
(29) An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following:		11.3.4 Avoided Costs

(A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including: (i) fuel cost; (ii) plant operation and maintenance costs; (iii) spinning reserve; (iv) emission allowances; (v) environmental compliance costs; and (vi) transmission and distribution operation and maintenance costs.		
(30) A summary of the utility's most recent public advisory process, including the following: (A) Key issues discussed. (B) How the utility responded to the issues. (C) A description of how stakeholder input was used in developing the IRP.		3 Public Participation Process
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.		6 Resource Options
170 IAC 4-7-5 Energy and demand forecasts Sec. 5.		
(a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following: (1) Historical load shapes, including the following: (A) Annual load shapes. (B) Seasonal load shapes. (C) Monthly load shapes. (D) Selected weekly load shapes. (E) Selected daily load shapes, which shall include summer and winter peak days and a typical weekday and weekend day.		11.1.3.2 Load Shapes; 12 Technical Appendix Attachments Attachment 4.1 2022/2023 CEI South Long-Term Electric Energy and Demand Forecast Report; Attachment 4.2 CEI South Hourly Load Data
(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.		11.1.3 Overview of Past Forecasts; 12 Technical Appendix Attachments Attachment 4.1 2022/2023 CEI South Long-Term Electric Energy and Demand Forecast Report
(3) Actual and weather normalized energy and demand levels.		11.1.3 Overview of Past Forecasts
(4) A discussion of methods and processes used to weather normalize.		11.1.3 Overview of Past Forecasts
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.		4.6 Energy and Demand Forecast (Reference Case)

(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system. (B) Customer classes or, rate classes, or both. (C) Firm wholesale power sales.		11.1.3 Overview of Past Forecasts
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.		12 Technical Appendix Attachments 4.1 2022/2023 CEI South Long-Term Electric Energy and Demand Forecast Report
(8) Justification for the selected forecasting methodology.		12 Technical appendix attachments 4.1 2022/2023 CEI South Long-Term Electric Energy and Demand Forecast Report
(9) A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools and analysis.		1.3.3.1 Advanced Metering Infrastructure; 11.1.2 Load Forecast Continuous Improvement
(10) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in section 4(14) of this rule.		n/a
(b) To establish plausible risk boundaries, the utility shall provide at least three (3) alternative forecasts of peak demand and energy usage including: (1) high; (2) low; and (3) most probable; peak demand and energy use forecasts.		7.3 Alternate Scenarios
(c) In determining the peak demand and energy usage forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (4) Price elasticity. (5) Penetration of new technology. (6) Demographic changes in population. (7) Customer usage. (8) Changes in technology. (9) Behavioral factors affecting customer consumption. (10) State and federal energy policies. (11) State and federal environmental policies.		4 Customer Energy Needs; 7.3 Alternate Scenarios; 12 Technical Appendix Attachments 4.1 2022/2023 CEI South Long-Term Electric Energy and Demand Forecast Report

170 IAC 4-7-6 Description of available resources		
Sec. 6. (a) In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the twenty (20) year planning period being evaluated: The net and gross dependable generating capacity of the system and each generating unit. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.		6.2 Current Resource Mix; 11.4.2 Approximate Net and Gross Dependable Capacity
(2) The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.		6.2 Current Resource Mix
(3) A fuel price forecast by generating unit. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.		12 Technical Appendix Attachments: Confidential Attachment 8.2 EnCompass Input/Output Model Files
(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and(D) subsequent disposal; and (E) water consumption and discharge; at existing fossil fueled generating units. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.		11.2 Environmental Appendix
(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce: (i) transmission losses; (ii) congestion; and (iii) energy costs.		11.7 Transmission Appendix

(C) An evaluation of the potential impact of demand-side resources on the transmission network.		
(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy. (a)(6) shall be provided for each year of the future planning period.		6.2.4 Energy Efficiency; 6.2.5 Demand Response; 6.3.2 DSM; 11.3 DSM Appendix
The information listed in subdivision (a)(1) through (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.		Included in Sec. 6 (a)(1) through (a)(4) and in subdivision (a)(6)
(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Rate design as a resource in meeting future electric service requirements.		6.3.2.7 Other Innovative Rate Design
(2) Demand-side resources. For potential demand-side resources, the utility shall include the following: (A) A description of the potential demand-side resource, including its costs, characteristics and parameters. (B) The method by which the costs, characteristics and other parameters of the demand-side resource are determined. (C) The customer class or end-use, or both, affected by the demand-side resource. (D) Estimated annual and lifetime energy (kWh) and demand (kW) savings. (E) The estimated impact of a demand-side resource on the utility's load, generating capacity and transmission and distribution requirements. (F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.		6.3.2 DSM; 12 Technical Appendix Attachments 6.2 2022 DSM Market Potential Study
(3) Supply-side resources. For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered, including the following: (i) Size in megawatts. (ii) Utilized technology and fuel type. (iii) Energy profile of nondispatchable resources. (iv) Additional transmission facilities necessitated by the resource. (B) A discussion of the utility's effort to coordinate planning, construction and operation of the supply-side resource with other utilities to reduce cost.		6 Resource Options; 11.2 Environmental Appendix; 12 Technical Appendix Attachments: Attachment 1.2 CEI South Technology Assessment Summary Table; Confidential Attachment 8.2 EnCompass Input Model Files

(C) A description of significant environmental effects, including the following: (i) Air emissions. (ii) Solid waste disposal. (iii) Hazardous waste and subsequent disposal. (iv) Water consumption and discharge.		
(4) Transmission facilities as resources. In analyzing transmission resources, the utility shall include the following: (A) The type of the transmission resource, including whether the resource consists of one (1) of the following: (i) New projects. (ii) Upgrades to transmission facilities. (iii) Efficiency improvements. (iv) Smart grid technology. (B) A description of the timing, types of expansion and alternative options considered. (C) The approximate cost of expected expansion and alteration of the transmission network. (D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost-effective resources. (E) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.		6.4 Transmission Considerations
170 IAC 4-7-7 Selection of resources		
Sec. 7. (a) To eliminate nonviable alternatives, a utility shall perform an initial screening of the future resource alternatives listed in section 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.		8.1.3 Portfolio Screening; Figure 11.36 New Construction Alternatives
170 IAC 4-7-8 Resource portfolios Sec. 8		
(a) The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used.		2.5 Portfolio Development; 8 Portfolio Development and Evaluation

In selecting the candidate resource portfolios, the utility shall at a minimum consider: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.		
(b) With regard to candidate resource portfolios, the IRP must include the following: (1) An analysis of how candidate resource portfolios performed across a wide range of potential future scenarios, including the alternative scenarios required under section 4(25) of this rule. (2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics. (3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.		8.2 Evaluation of Portfolio Performance; 9.1.2 Affordability; 11.6.8 Affordability Ranking
(c) Considering the analyses of the candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following: (1) A description of the utility's preferred resource portfolio. (2) Identification of the standards of reliability. (3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio. (4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of: (A) safety; (B) reliability; (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.		2.3.2.1 Reliability; 6 Resource Options; 8 Portfolio Development and Evaluation; 9.1 Preferred Portfolio Recommendation
(5) An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, reliably, efficiently and cost-effectively meets the electric system demand taking cost, risk and uncertainty into consideration.		9.1 IRP Preferred Portfolio Recommendation

(6) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system.		N/A
(7) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio. (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.		9. IRP Preferred Portfolio; 10.2.5 Ability to Finance the Preferred Portfolio, 11.3.5 Avoided Costs, 11.6.7 Affordability Ranking; 12 Technical Appendix Attachments, Confidential Attachment 8.2 EnCompass Input/Output Model Files
(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance; (ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (v) operating costs; (vi) construction costs; (vii) resource performance; (viii) load requirements; (ix) wholesale electricity and transmission prices; (x) RTO requirements; and (xi) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.		2 CEI South's IRP Process; 5 The MISO Market; 7.2 Reference Case Scenario; 7.3 Alternate Scenarios; 8.2 Evaluation of Portfolio Performance; 9 Preferred Portfolio; Confidential Attachment 8.2 EnCompass Input/Output Model Files
(9) Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.		10.2 Discussion of Plans for the Next 3 years; 11.1.2 Load Forecast Continuous Improvement
(10) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including changes in the following:		8.2 Evaluation of Portfolio Performance; 9 Preferred Portfolio

(A) Demand for electric service. (B) Cost of new supply-side resources or demand-side resources. (C) Regulatory compliance requirements and costs. (D) Wholesale market conditions. (E) Fuel costs. (F) Environmental compliance costs. (G) Technology and associated costs and penetration. (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.		
170 IAC 4-7-9 Short term action plan Sec. 9		
(a) A utility shall prepare a short term action plan as part of its IRP and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule.		10 Short Term Action Plan
(b) The short-term action plan shall summarize the utility's preferred resource portfolio and its workable strategy, as described in section 8(c)(9) of this rule, where the utility must act or incur expenses during the three (3) year period.		10 Short Term Action Plan
(c) The short term action plan must include, but is not limited to, the following: (1) A description of resources in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective.		10 Short Term Action Plan
(2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10, 170 IAC 4-8-1 *et seq*. and consistent with the utility's longer resource planning objectives.		10.2.2 DSM
(3) The implementation schedule for the preferred resource portfolio.		10.3 Implementation Schedule for the Preferred Resource Portfolio
(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.		10.2 Discussion of Plans for the Next 3 Years; Confidential Attachment 8.2 EnCompass Input/Output Model Files
(5) A description and explanation of differences between what was stated in the utility's last filed short-term action plan and what actually occurred.		10.1 Differences Between the Last Short Term Action Plan from What Transpired

List of Acronyms/Abbreviations

1898 & Co.	1898 & Co., a part of Burns & McDonnell
ABB	Power Consulting Company
ABB	A.B. Brown Generating Station
AC	Alternating Current
ACE	Affordable Clean Energy
AEO	Annual Energy Outlook
AMI	Advanced Metering Infrastructure
ATC	Around the Clock
AUPC	Average Use Per Customer
BAGS	Broadway Avenue Generating Station
BAU	Business as Usual
BES	Bulk Electric System
BEV	Battery Electric Vehicles
BSER	Best System of Emission Reduction
Btu	British Thermal Unit
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
CAC	Citizens Action Coalition
CAGR	Compound Annual Growth Rate
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Day
CHP	Combined Heat and Power
CNP	CenterPoint Energy
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
CONE	Cost of New Entry
COVID	Corona Virus Disease
CPCN	Certificate of Public Convenience and Necessity
CSA	Coordinated Seasonal Transmission Assessment
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
CWIS	Cooling Water Intake Structures
C&I	Commercial and Industrial
DC	Direct Current
DG	Distributed Generation
DGS	Demand General Service
DLC	Direct Load Control
DLOL	Direct Loss of Load
DPP	Definitive Planning Phase
DR	Demand Response

List of Acronyms/Abbreviations (Cont.)

DSM	Demand Side Management
DSMA	Demand Side Management Adjustment
EE	Energy Efficiency
EEFC	Energy Efficiency Funding Component
EGU	Electric Generation Units
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines
EM&V	Evaluation, Measurement and Verification
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitator
EV	Electric Vehicle
EVA	Energy Ventures Analysis, Inc.
FBC	F.B. Culley Generating Station
FBC3	F.B. Culley Unit 3
FDNS	Fixed Slope Decoupled Newton-Raphson
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
GDP	Gross Domestic Product
GE	General Electric
GHG	Greenhouse Gas
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GPS	Global Positioning System
GS	General Service
GW	Gigawatt
GWh	Gigawatt Hour
HB	House Bill
H_2SO_4	Sulfuric Acid
HDD	Heating Degree Days
Hg	Mercury
HHV	Higher Heating Value
HLF	High Load Factor
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning
IC	Internal Combustion
ICAP	Installed Capacity
IDEM	Indiana Department of Environmental Management
ILB	Illinois Basin
IMPA	Indiana Municipal Power Agency
Ind	Indiana
IRA	Inflation Reduction Act

List of Acronyms/Abbreviations (Cont.)

IRP	Integrated Resource Plan
ISB	Intelligent Sootblowing
ISO	Independent System Operator
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
lb	Pound
LCOE	Levelized Cost of Energy
LCR	Local Clearing Requirement
LDES	Long Duration Energy Storage
LGE/KU	Louisville Gas and Electric/Kentucky Utilities
Li-ion	Lithium-ion
LMP	Local Marginal Pricing
LMR	Load Modifying Resources
LOLE	Loss of Load Expectation
LP	Large Power
LRR	Local Reliability Requirement
LRZ	Local Resource Zone
MATS	Mercury and Air Toxics Standards
MEEA	Midwest Energy Efficiency Alliance
MISO	Midcontinent Independent System Operator
MLA	Municipal Levee Authority
MMBtu	One Million British Thermal Unit
MMWG	Multiregional Modeling Working Group
MPS	Market Potential Study
MSA	Metropolitan Statistical Area
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standard
NDA	Non-Disclose Agreement
NERC	North American Electric Reliability Council
NERC MOD	NERC Modeling, Data and Analysis
NIPSCO	Northern Indiana Public Service Company
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NPVRR	Net Present Value Revenue Requirement
NREL	National Renewable Energy Lab
NRIS	Network Resource Integration Service

List of Acronyms/Abbreviations (Cont.)

NTG	Net to Gross
NU	Network Upgrade
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
OMS	Organization of MISO States
ORSANCO	Ohio River Valley Sanitation Commission
OUCC	Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PC	Pulverized Coal
PHEV	Plug-in Hybrid Electric
PJM	Pennsylvania New Jersey Maryland Interconnection LLC
PM	Particulate Matter
PPA	Purchase Power Agreement
PPT	Parts Per Trillion
PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PSEG	Public Service Electric and Gas
PTC	Production Tax Credit
PV	Photovoltaic
RAN	Resource Availability and Need
Res	Residential
RF	ReliabilityFirst
RFP	Request for Proposals
RIIA	Renewable Integration Impact Assessment
RIM	Ratepayer Impact Measure
RS	Residential
RTO	Regional Transmission Operator
SAE	Statistically Adjusted End-use
SBS	Sodium Based Sorbents
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SD	Standard Deviation
SEA	Senate Enrolled Act
SERC	Southeast Reliability Corporation
SGS	Small General Service
SIGECO	Southern Indiana Gas and Electric Company
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide

List of Acronyms/Abbreviations (Cont.)

TDSIC	Transmission, Distribution and Storage System Improvement Charge
T&D	Transmission and Distribution
TRC	Total Resource Cost
UC	Utility Cost
UCAP	Unforced Capacity
UCT	Utility Cost Test
V	Volt
VAR	Volt-Amp Reactance
VER	Variable Energy Resources
VFD	Variable Frequency Drive
WN	Weather Normalized

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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.

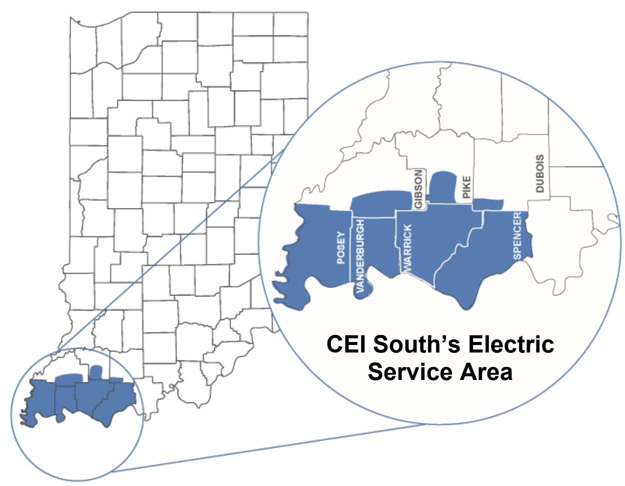
The resource options selected in this plan provide a bridge to the future. For example, the gas conversion allows battery storage technology to become more competitive in price and develop longer duration storage capabilities. Further, should there be a need for new baseload generation to accommodate 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 ("H2S04") 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

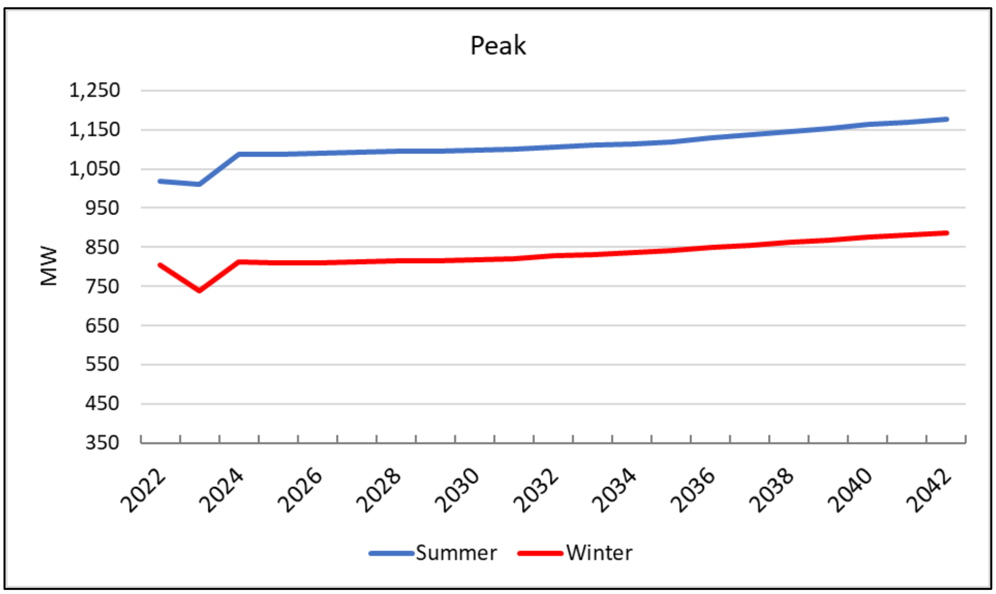
on reliability, affordability, resiliency, stability, risk, resource diversity, and environmental sustainability. The IRP process has become increasingly complex in nature as MISO implements updated resource accreditation methodologies to maintain reliability of the system that includes increased levels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

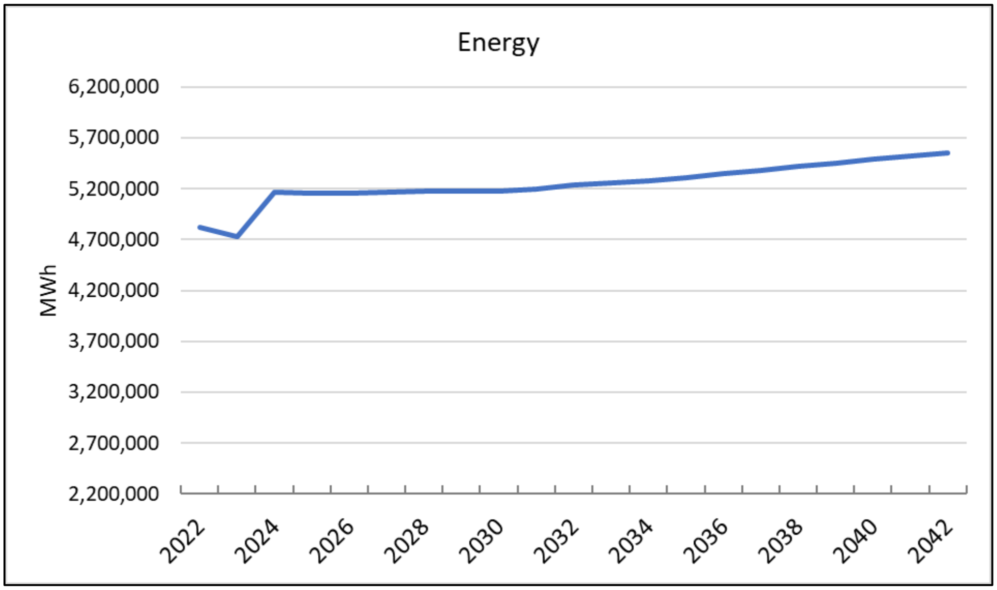
A. Customer Energy Needs

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

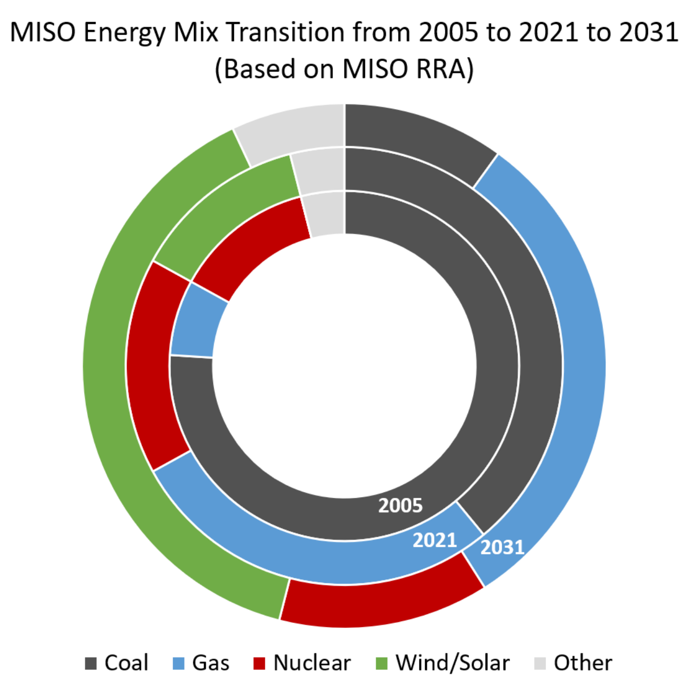
The next step in an IRP is identifying resource options to satisfy customers' anticipated need. Many resources were evaluated to meet customer energy needs over the next 20 years. CEI South considered both new and existing resource options. 1898 & Co., a well-respected engineering firm, conducted an 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

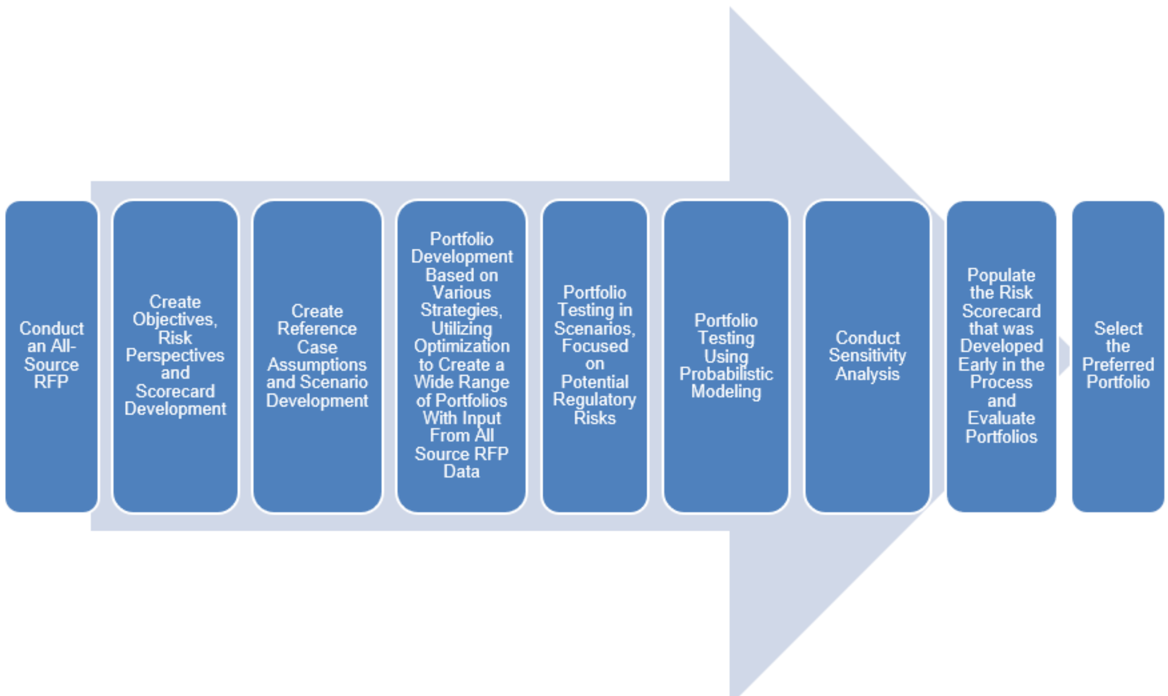
The future is far from certain. Uncertainty creates a risk that a generation portfolio that is reasonable under an anticipated future fails to perform as expected if the future turns out differently. CEI South's IRP analysis was developed to identify the best resource mix of generation and energy efficiency 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

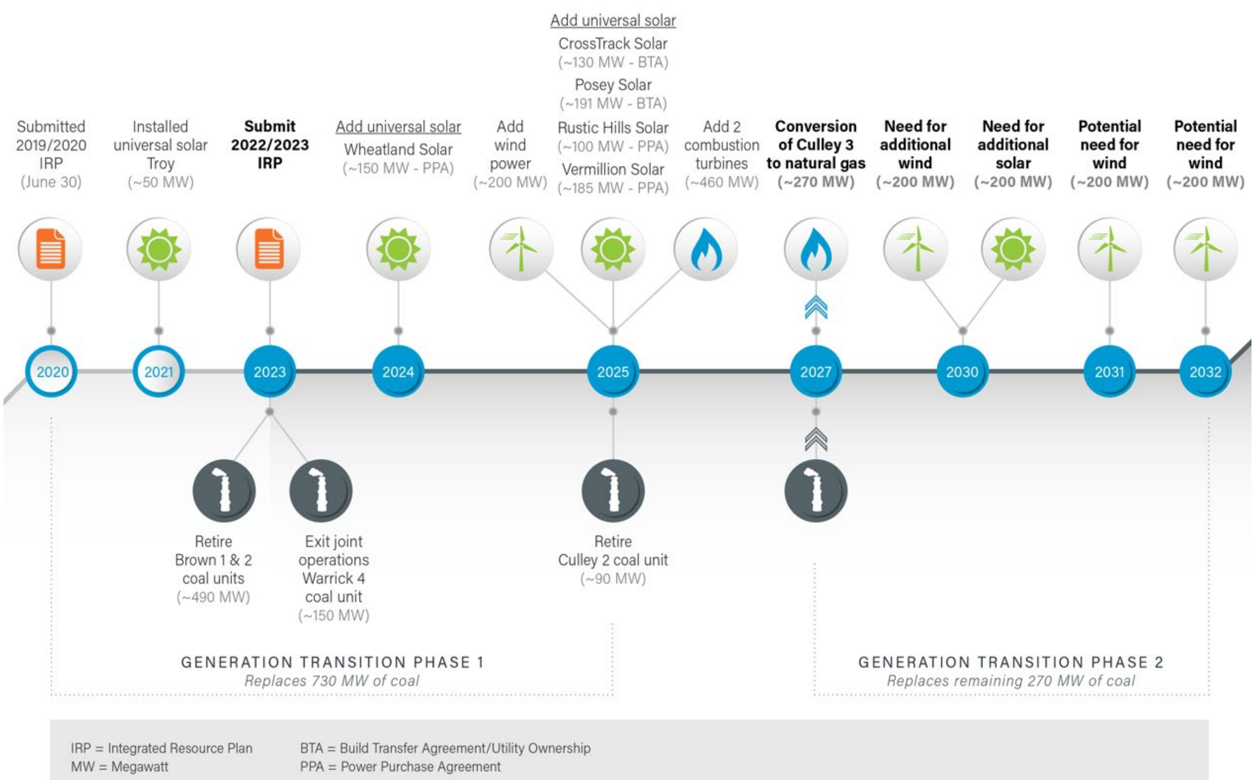
Request	Response
Incorporate more than proposed 10-20 MWs of Industrial DR	CEI South included 25 MWs of industrial DR as a resource. Currently, CEI South does not have any industrial DR registered with MISO. CEI South is engaged in conversations with a demand response aggregator to capture the potential 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.

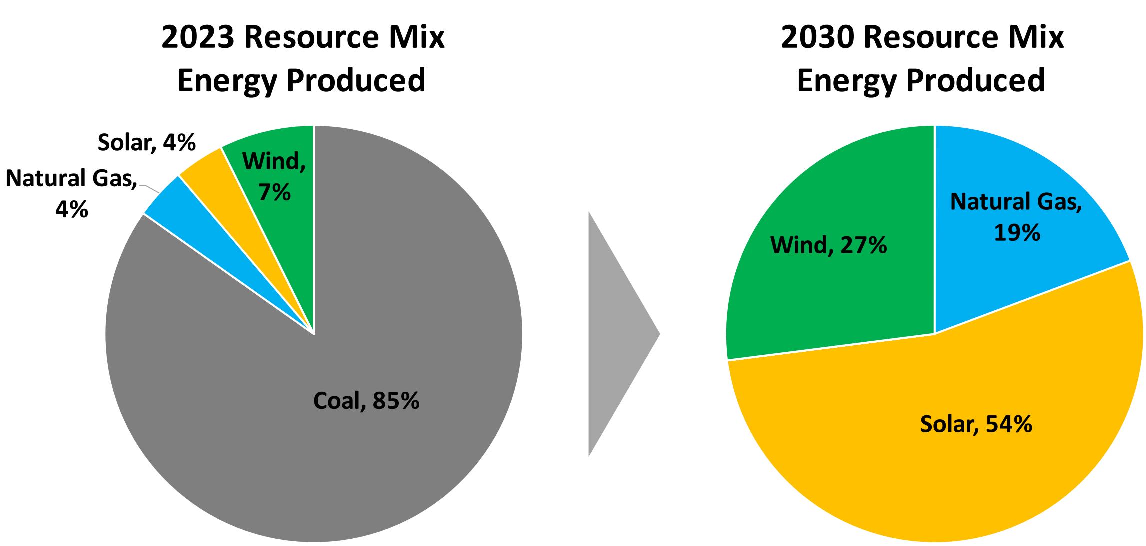


This preferred portfolio:

- 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.

SECTION 1
OVERVIEW

1.1 COMPANY BACKGROUND

CEI South is an indirect subsidiary of CenterPoint Energy, Inc. On February 1, 2019, CenterPoint Energy, Inc. (NYSE: CNP) and Vectren Corporation (NYSE: VVC) completed a merger. CenterPoint Energy is headquartered in Houston, has regulated electric businesses serving 2.8 million metered customers in the greater Houston area and in Southwest Indiana and natural gas utility businesses in six states that serve more than 4 million homes and businesses.

Operation of CEI South's electric transmission and distribution services, including its power generation and wholesale power operations now fall into CEI South. CEI South serves more than 150,000 customers in Southern Indiana.

1.2 INTEGRATED RESOURCE PLANNING

CEI South takes integrated resource planning very seriously. The IRP is used as a guide for how CEI South will serve existing and future customers over the next 20 years in a reliable and economic manner. The integrated resource plan can be thought of as a compass setting the direction for future generation and Demand Side Management ("DSM") options. It is not a turn-by-turn GPS. Future analyses of changing conditions, filings and subsequent approvals from the IURC are needed to chart the specific course.

CEI South is required to submit its IRP to the IURC every three years and last submitted it in 2020 with a plan to transition its generation fleet away from a majority reliance on coal to a diversified portfolio of renewable generation, complimented by quick start, fast ramping natural gas combustion turbines. CEI South began this IRP process by gathering feedback from stakeholders on the last IRP and the Final Director's Report for the 2019/2020 Integrated Resource Plan. Additionally, CEI South worked closely with IRP stakeholders throughout the process, including multiple tech-to-tech discussions and information sharing between public stakeholder meetings, as discussed in Chapter 3 Public Participation Process.

The future is uncertain; several factors have helped to set the stage for this analysis. Multiple, rapid changes engulfed the world, effecting energy and capacity markets following the COVID stay at home orders. The threat of tariffs, an investigation by the US Commerce Department on forced labor in China, and supply chain issues stemming from the lockdowns all worked to greatly increase solar costs and delay projects across the country. Simultaneously, natural gas prices become more volatile with the war in Ukraine, going up in the summer of 2022 to levels not seen in years. With increased natural gas prices and rampant inflation, electricity prices soared in 2022. Additionally, MISO market capacity prices reached Cost of New Entry ("CONE") for the 2022/2023 planning year across MISO's North and Central regions, earlier than expected. Capacity shortages are still projected as capacity rich resources are retired for intermittent, renewable resources.

MISO continues to make changes to ensure reliability of the system. MISO has been actively updating rules and mechanisms to ensure reliability as we evolve toward a more complex, less predictable future. MISO foresees a shift towards primarily weather dependent resources, less predictable resource outages or unavailability, less predictable weather, scarcity of essential reliability attributes, and increasing load. All have led MISO to plan for providing energy for the worst week in each season verses the traditional approach, which is to plan for resources to meet load during the peak hour of the year, typically in the summer across the Midwest. To deal with these challenges, MISO has implemented and continues to implement changes and has shifted focus to resources that have the following priority system attributes: availability, fuel assurance, ramp capability, long duration energy at high output, rapid start-up, and voltage stability.

Based on expectations of increasing penetration of renewables, particularly solar, MISO, CEI South's regional transmission operator, continues to evaluate rules and mechanisms that are needed now and in the future to maintain reliability. CEI South continues to monitor developments within MISO; the outcomes of several strategic studies are important for resource planning. 1) MISO completed a Renewable Integration Impact Assessment ("RIIA"), a rigorous analysis that evaluated increasing amounts of wind and solar resources on the Eastern Interconnection bulk electric system, with a focus on the MISO footprint over the long term. This assessment demonstrated that as renewable energy penetration increases, so does the magnitude of the bulk electric system need and risk. The results show that MISO will undergo required transformational change in planning, markets, and operations. 2) MISO published the Resource Availability and Need ("RAN") whitepaper, where MISO describes the reliability imperative and the need to align the availability, flexibility and visibility of both supply and demand resulting in reliable and efficient operations every hour of the year. 3) The Reliability Imperative is a "living" report that prioritizes MISO's interconnected initiatives that addresses the region's challenges within four pillars Market Redefinition, Transmission Evolution, System Enhancements, and Operations of the Future. The Market Redefinition pillar takes a granular look at the planning and accreditation of a changing resource mix, more frequent extreme weather events and the shifting needs and challenges of ensuring sufficient resources during high-risk periods. 4) MISO's Annual Regional Resource Assessment ("RRA") provides a collective view of how members' resource plans are evolving, revealing key insights and implications that can inform the work that members, states, and MISO are doing to balance reliability, affordability, and sustainability priorities. One such insight showed that as the solar generation fleet grows, the system will have a much greater need for controllable ramp-up capability. Maximum short-duration up-ramps increase by three to four times between 2031 and 2041 compared to current levels. This prompted MISO to launch an initiative to identify system reliability attributes that, under current market constructs, could become scarce due to the region's rapidly evolving mix of generation.

Per stakeholder request, CEI South chose to move away from the Aurora modeling platform to a more transparent tool, EnCompass. It maintains essential tools needed to conduct an IRP, while providing more transparency, greater speed of results, and greater flexibility. The output from this model provides quantitative data to help evaluate portfolios within a robust risk analysis designed to understand performance over a wide range of futures. A great benefit of the tool is that CEI South was able to model MISO's seasonal construct and quickly make changes to account for MISO's rapid evolution.

1.2.1 IRP Objectives

CEI South's IRP strategy is designed to accommodate the ongoing changes and uncertainties in the competitive and regulated markets. The main objective is to select a preferred portfolio[13] of supply and demand resources to best meet customers' needs for reliable, reasonably priced, sustainable power over a wide range of future market and regulatory conditions, taking into account risk and uncertainty. Specifically, CEI South's objectives are as follows:

- Safe Reliable Service (a requirement for all portfolios)
- Affordability (reflected in the balanced scorecard)
- Environmental Risk Minimization (reflected in the balanced scorecard)
- Cost Uncertainty Risk Minimization (reflected in the balanced scorecard)
- Avoiding Overreliance on Market Risk for capacity and energy (reflected in the balanced scorecard)
- Future Flexibility (reflected in both offramps and "other considerations")
- Resource Diversity (reflected in "other considerations")
- System Flexibility (operational flexibility to support renewable resources)

1.2.2 IRP Development

CEI South continues to incorporate feedback from IRP stakeholders and IURC staff. Specific feedback was incorporated into the 2022/2023 IRP process. First, CEI South incorporated feedback directly into its All-Source RFP, discussed further in chapter 3. As in the last IRP, CEI South made several commitments to IRP stakeholders to maintain improvements from prior IRPs and to strengthen the analysis with new improvement opportunities, most notably with the introduction of tech-to-tech meetings throughout the process and increased file/data sharing at multiple points in the process. This allowed stakeholders to review modeling inputs, model settings, and outputs in real time during the analysis. CEI South is appreciative to stakeholders who took time to review this information in detail and provide timely feedback. This setting allowed for more productive

[13] A portfolio is a mix of future supply and demand side resources to meet expected future demand for electricity.

conversations and allowed for sharing of confidential information with those that signed an NDA.

CEI South worked closely with industry experts to develop a comprehensive analysis. 1898, a Burns & McDonnell Company, (“1898”, “1898 and Company”, or “1898 & Co.”) managed all aspects of the All-Source RFP. This analysis was utilized to provide current market pricing for resources and an opportunity for CEI South to pursue individual projects to help serve CEI South customers following the conclusion of the IRP. 1898 & Co. also worked with CEI South to conduct scenario development, modeling and a comprehensive risk analysis, which included both scenario based and probabilistic modeling. CEI South also worked with GDS to convert Market Potential Study outputs into IRP inputs, and 1898 modeled these demand side resources on a consistent and comparable basis with supply side resources.

1.3 CHANGES SINCE THE 2019-2020 IRP

Several developments have occurred since the last IRP was submitted in June 2020, which help to illustrate the dynamic nature of integrated resource planning. The IRP analysis and subsequent write up represent the best available information at a point in time. The following sections discuss some of the major changes that have occurred over the last three years. CEI South realizes conditions will change, and this analysis was designed to test portfolios under a wide range of plausible futures.

1.3.1 Generation

1.3.1.1 Generation Transition Plan

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 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.

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 Office of Utility Consumer Counselor (“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.

1.3.1.2 FERC 2222

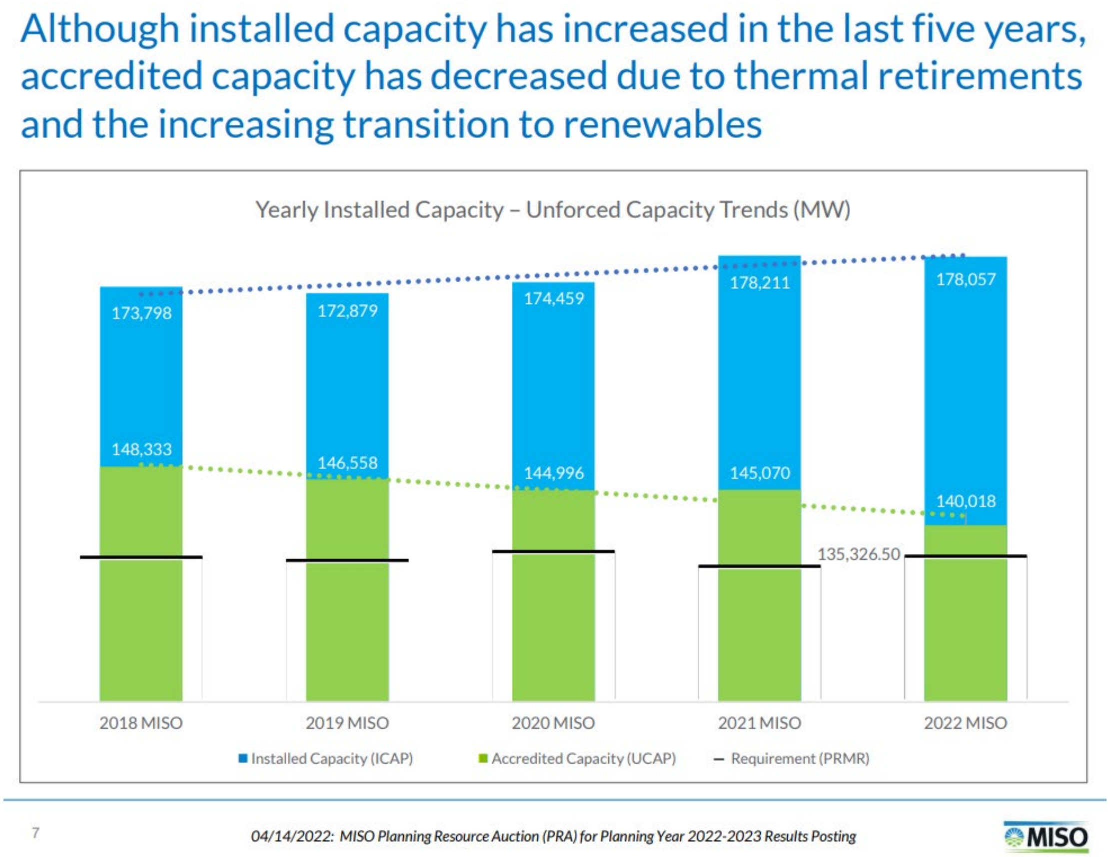
FERC Order No. 2222 instructs Regional Transmission Operators (“RTO”) and Independent System Operators (“ISO”), like MISO, to allow for Distributed Energy Resource (“DER”) aggregations to participate directly in the wholesale markets and establish a new category of market participants. A DER is considered any resource located on the distribution system, any subsystem thereof or behind a customer meter.

These resources include, but are not limited to demand response, behind the meter generation (renewable or thermal), electric vehicles or energy efficiency. FERC issued the order on September 17, 2020, which required RTOs/ISOs to submit compliance filings outlining their implementation plans and effective dates for DER market participation. MISO has proposed to permit DER aggregations participation in the MISO Market starting in 2030. The Indiana Commission has initiated an investigation into how this order will affect resource planning. It will require unprecedented coordination among regulators, market participants, MISO, and utilities to ensure a smooth transition. It is too soon to fully foresee all the implications for resource planning.

1.3.1.3 MISO Capacity Market

For the 2022-2023 planning year MISO's north and central regions experienced a capacity shortfall resulting in all of these local resource zones to clear at CONE ("Cost of New Entry"), which is the maximum clearing price and was a significant increase over historical auction results. MISO noted that there is a growing gap between the accredited capacity of retiring thermal resources and the accredited capacity of new intermittent resources coming online. Figure 1.1 below illustrates how this gap has grown from 2018-2022.

Figure 1.1 MISO Accredited and Installed Capacity[14]



At the time MISO noted that unless more capacity is built that can supply reliable generation, shortfalls highlighted in the 2022-2023 auction will continue.

In the 2023-2024 seasonal planning resource auction clearing prices dropped when compared to the 2033-2023 auction with an average seasonal clearing price around $10/MW-Day in MISO's North/Central region. This decrease is auction clearing price could be temporary if retirements outpace the installation of new capacity. MISO's continued resource adequacy reforms, particularly accreditation reforms, could also impact the amount of capacity available to meet the systems reserve requirements resulting in an increase in the clearing price of future auctions.

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[14] MISO 2023/2023 PRA Results – April 14, 2022; Page 7
https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf

1.3.1.4 Alcoa Contract

Alcoa and CEI South have jointly owned and operated the 300 MW Warrick 4 unit since 1970. It is still CEI South's intention to exit the Joint Operating Agreement ("JOA") for CEI South's share of Warrick Unit 4 at the end of the contract term, December 31, 2023; however, discussions with Alcoa related to the possible extension of the JOA beyond the contract term are ongoing. While continuing to speak to Alcoa about Warrick 4 options, the working assumption is this IRP is that Warrick 4 will no longer be in CEI South's fleet by the end of the contract.

1.3.1.5 Solar Energy Tariff, Sanctions and Supply Chain Issues

China is a major producer of solar panels and other solar products. Certain solar cells, modules, laminates, and panels from China are subject to various antidumping and countervailing duty rates, depending on the exporter supplying the product, imposed by the U.S. government as a result of determinations the United States was materially injured as a result of such imports being sold at less than fair value and subsidized by the Chinese government.

In March 2022, the Department of Commerce ("DOC") announced it would initiate an investigation into whether imports of solar cells and panels produced in Cambodia, Malaysia, Thailand and Vietnam ("CMVT") are circumventing U.S. rules and laws, such as antidumping and countervailing duty rates, which impose a tariff on imports of solar cells and panels manufactured in China.

In June 2022, the Biden Administration announced a two-year tariff exemption period for solar energy imports from the CMTV countries. In the context of the Auxin inquiry, this means that if the DOC concluded China was using manufacturers in the CMTV countries to evade U.S. trade regulations, entries of covered products from those manufacturers would be eligible for a waiver of the otherwise applicable anti-circumvention tariffs until at least June 5, 2024.

In December 2022, the DOC issued its preliminary findings noting that circumvention was occurring in each of the four countries. If an affirmative finding is made by the DOC, it could impose duties on imports of solar cells and panels from CMVT with both forward-looking and retroactive application.

In addition, in December 2021, President Biden signed into law the Uyghur Forced Labor Prevention Act, which bans goods from China's Xinjiang region due to the use of forced labor.

Lastly, continuing tensions between the United States and China may lead to restrictions in trade between the two countries or new legislation, tariffs or bans, any of which could further negatively impact the supply of solar panels. These or similar duties and legislation have and may in the future also put upward pressure on prices of these solar energy products, which may reduce our ability to acquire these items in a timely and cost-efficient manner.

1.3.1.6 MISO Resource Adequacy Changes

Historically, MISO's approach to resource adequacy has focused on ensuring that sufficient resources would be available when demand peaks in the summer with the expectation that serving load the rest of the year would be comparatively easier. But given the increase in MaxGen emergencies in recent years in non-summer seasons, MISO evaluated several traits of their current construct such as the granularity, risk metrics, Planning Resource Auction ("PRA") auction design, reliability requirement, and market signals. Their evaluation developed into an extensive stakeholder process that ultimately concluded with MISO filing tariff changes to Federal Energy Regulatory Commission ("FERC"). The proposed changes included a seasonal resource adequacy construct to address significant increases in emergency events that occur year-round, driven by factors including generation retirements, reliance on intermittent resources, outages resulting from extreme weather events, and declining excess reserve margin along with a proposal to implement seasonal, availability-based accreditation ("SAC") to establish capacity values for thermal and demand response resources.

1.3.1.7 Implementation of Approved MISO Seasonal Construct and Accreditation

The MISO region is transitioning from a generation portfolio dominated by coal and nuclear resources to a portfolio that increasingly relies on intermittent and emergency-only resources. Generation retirements are accelerating this transition and have caused MISO to operate with decreasing capacity margins.

As a result of the evolving resource fleet, MISO determined that its resource adequacy mechanism fell short of supporting reliability in all hours of the year. The identified deficiencies include: (1) mechanisms did not incent members to add their resources and required capabilities to the resource pool; and (2) the current reserve margin analysis did not adequately reflect variations in resource production and other seasonal risk factors. On November 30, 2021, (in Docket No. ER22-495-000) MISO made a filing with FERC to address these issues through proposed revisions to its Open Access Transmission, Energy and Operating Reserve Markets Tariff. MISO filed amendments to its proposal on April 8, 2022. On August 31, 2022, FERC issued an Order accepting MISO's tariff revisions subject to condition. On September 29, 2022, MISO submitted a compliance filing pursuant to FERC's Order. On September 30, 2022, several parties timely sought rehearing of FERC's Order; those requests were deemed denied by operation of law on October 31, 2022.

MISO's proposal included a sub-annual resource adequacy construct consisting of four separate seasonal reserve margin targets and capacity auctions to better reflect variation in capacity accreditation and capacity needs across the year. The construct is premised on four three-month seasons. Each season accounts for special attributes, such as winter weatherization and applies the capacity resource must-offer requirement to only the seasons for which the capacity resource is cleared to allow units to be operated seasonally. MISO will also simultaneously conduct four separate seasonal analyses to reflect transfer limits between its resource-adequacy zones. In addition, MISO revised its loss-of-load expectation analysis to model more accurately seasonally sensitive variables.

MISO also proposed to revise its resource accreditation to reflect real-time availability and seasonal performance of generation assets to mitigate reliability risks while improving coordination of planned outages. The revised accreditation process includes a two-tiered weighting approach to emphasize availability during “tight” critical need periods (Tier 2) but also general availability in “non-tight” hours (Tier 1). Resources that are not online during critical need periods are penalized if their lead time exceeds 24 hours. Regardless of the tier, coordinated outages are fully exempt from penalty if (1) the generator owner or operator schedules its first planned outage 120 days or more in advance of the outage start date and certain projected Maintenance Margin levels are met; and (2) the generator owner or operator reschedules its planned outage at MISO’s request due to certain enumerated conditions. In addition, partial outage-related exemptions are available under certain circumstances for time periods outside of “highest need.”

The approved tariff changes were implemented beginning with the 2023/2024 Planning Year and are a component of the next phase of MISO’s ongoing RAN initiative.

1.3.2 Environmental Rules

1.3.2.1 Rules Update

1.3.2.1.1 Air

Periodic updates to air emission regulations under the Clean Air Act continue to challenge the daily operations of coal-fired electric generating units. Over time emission limits have gotten lower, emission averaging times have gotten shorter, and allowance pools have been significantly restricted, presenting increasing challenges to maintaining consistently high levels of compliance. These compliance challenges are further exacerbated as these units are called upon to cycle in lieu of baseload operation.

1.3.2.1.1.1 Cross-State Air Pollution Rule and "Good Neighbor" Rule

Since our previous IRP the US Environmental Protection Agency ("EPA") has finalized revisions to several regulations under the Clean Air Act that imposed more stringent requirements and make coal fired EGUs increasingly difficult and costly to operate. The most recent CSAPR Update Rule was published in the Federal Register on April 30, 2021 and became effective June 29, 2021. This final rule reduced emissions of nitrogen oxides ("NOx") from power plants in 12 states, which included Indiana. As part of the implementation of that rule, EPA adjusted those states' emissions budgets for ozone season, beginning with the 2021 ozone season. The impact to A.B. Brown and F.B Culley was a nearly 20% reduction in allocated allowances for the 2021 ozone season. The ozone season NOx allowance allocation total for A.B. Brown, F.B. Culley, and Warrick 4 for 2020 was 1,355. The allocation was reduced to 1,167 for the 2021 ozone season, and for the 2022 ozone season it was further reduced to 851. CEI South made significant efforts to reduce NOx emissions, however still had to purchase costly allowances to make up for the difference. Moreover, the recently signed Good Neighbor rule has added 11 states to Group 3, and while the allocations to CEI South facilities are primarily unchanged, the addition of 11 states to Group 3 coupled with an annual recalibration of the emissions allowance bank based upon retiring units has the potential to continue impacting the cost of allowances in the market. Additionally, the regulation has a "backstop" NOx emission rate that may be more stringent than the current rates at F.B. Culley when considering the rule proposes a daily rate versus the current 30-day rolling average in place for Culley, in which case Culley could have to surrender seasonal NOx allowances at a ratio of 3-for-1. This backstop would first apply in the 2024 ozone season. A further backstop requirement could require utilities to operate Selective Catalytic Reduction ("SCRs") at a higher efficiency level, even if ozone season NOx allowances are available.

1.3.2.1.1.2 Mercury and Air Toxics Standards Rule ("MATS")

EPA has proposed to strengthen and update the MATS rule for coal-fired power plants by proposing more stringent emissions limits and additional monitoring and control methods based upon its risk and technology review. As proposed, the rule would significantly reduce the emission limit for particulate matter ("PM") from 0.03 lb/mmBTU to 0.010 lb/mmBTU, and EPA is taking comment on an even lower PM emission rate.

1.3.2.1.1.3 Fine Particulate NAAQS

In addition to the proposed revisions to PM emission limits in MATS EPA has also proposed to lower the National Ambient Air Quality Standards ("NAAQS") primary annual PM2.5 level from 12.0 µg/m3 to within the range of 9.0 to 10.0 µg/m3. EPA also requested comments on an alternative standard of annual PM2.5 values 8.0 or 11 µg/m3 and a 24-hour NAAQS value of 25 ug/m3. After the regulation is finalized, air quality for individual counties will be assessed and designated as either in attainment or nonattainment for meeting the new standard. A nonattainment designation would require a state implementation plan to improve air quality and could add additional costs to operate the coal-fired Electric Generating Units ("EGU") under a reduced standard.

1.3.2.1.1.4 Greenhouse Gas Regulations

EPA finalized the Affordable Clean Energy rule ("ACE") repealing and replacing the Clean Power Plan in June 2019. The ACE rule established carbon dioxide ("CO_2") emission guidelines for states to use when developing plans to limit CO_2 at coal-fired EGUs within the state. ACE established heat rate improvement, or efficiency improvement, as the Best System of Emissions Reductions ("BSER") for CO_2 from coal-fired EGUs. States were given six candidate technologies to be considered as BSER along with their calculated efficiency improvements and costs to implement and operate. States are to establish unit-specific standards of performance that reflect the emission limitation achievable through application of the BSER technologies with consideration of “the remaining useful life of the source” and other source-specific factors. State Implementation Plans are due April 2024 with compliance planned to begin within 24 months of submission. As the ACE Rule was in place during the current IRP modeling process, compliance with the Rule was modeled as a methodology to attribute a carbon cost to future operations.

On May 10, 2023, the EPA released a pre-publication version of a new set of proposed regulations under CAA Section 111 to address GHG emissions from new and modified EGUs. These new regulations would replace ACE. EPAs proposal presents an array of compliance requirements for different types of fossil-based units that would take effect at different times. Specifically, EPA is proposing to finalize new guidelines for states to regulate existing coal-fired EGUs under Section 111(d), new source performance standards for new natural gas-fired EGUs under Section 111(b), and guidelines for states to regulate existing natural gas-fired EGUs under Section 111(d). For coal-fired EGUs the proposal would set the best system of emission reductions as the use of carbon capture and sequestration, however the proposal provides off-ramps for units slated for retirement. For new and modified gas-fired units the proposal would establish a system of best management practices, efficiency targets and co-firing options depending upon the size and utilization of the units.

1.3.2.1.2 Water

On September 30, 2015, EPA published the final Effluent Limitations Guidelines rule (“ELG”). The rule sets strict technology-based limits for wastewaters generated from fossil fuel fired generating facilities and will force significant operational and technological changes at coal-fired power plants. EPA finalized the rule with a hybrid of the most stringent of the proposed options for fly ash transport water, bottom ash transport waters and Flue Gas Desulfurization (“FGD”) wastewaters.

While the 2015 final rule includes reference to multiple wastewaters, the key elements applicable to CEI South are FGD wastewaters and ash transport waters. Specifically, FGD wastewaters must meet new limits for arsenic, mercury, selenium, and nitrate / nitrite at the end of the wastewater treatment system and prior to mixing with any other process waters. Water used to transport bottom ash or fly ash is prohibited from discharge in any quantity, which effectively forces the installation of dry or closed loop ash handling systems. In September 2017, the ELG Postponement Rule was published. The Postponement Rule delayed the applicability date for the Bottom Ash Transport Waters ("BATW") from November 1, 2018 to November 1, 2020, but the no later than December 31, 2023 date for completion remained in place. In October 2020, the ELG Reconsideration Rule was published. The Reconsideration Rule changed the no later than date for discharge of Bottom Ash Transport Water from December 31, 2023 to December 31, 2025. It also provided an additional two years for FGD wastewater compliance, however CEI South was already committed to a Zero Liquid Discharge system under conditions of the F.B. Culley National Pollutant Discharge Elimination ("NPDES") permit, along with planning for eliminating waste streams in preparation for the closure of the East Ash Pond.

The A.B. Brown and F.B. Culley NPDES permits were renewed and became effective in early 2023. The F.B. Culley permit was modified as appropriate to allow for the BATW date extension allowed by the ELG Reconsideration Rule. As required by the ELG Rule and consequently the NPDES permits, F.B. Culley has ceased the discharge of Fly Ash Transport Water ("FATW") and completed the conversion of bottom ash on Unit 3 to a dry system in December 2020. For FGD wastewaters at F.B. Culley, alternate, but more restrictive limits were voluntarily agreed to which would automatically extend the applicability date to December 31, 2023. Technology to meet the more restrictive limits included the installation of zero liquid discharge equipment that would eliminate all discharge of FGD wastewater. This technology went into service on May 1, 2023.

1.3.2.1.3 Waste

The Coal Combustion Residuals Rule ("CCR") was finalized on April 17, 2015. The rule regulates the final disposal of CCRs which include fly ash, bottom ash, boiler slag and flue gas desulfurization solids. The rule is applicable to all new and existing landfills and surface impoundments used to store or dispose of CCRs at a power plant that was generating electricity on the effective date of the rule (October 2015). The rule establishes operating criteria and assessments as well as closure and post closure care standards. The "Phase 1, Part 1" rule was published on July 30, 2018, and became effective on August 28, 2018. This rule delayed the deadline by which facilities must cease the placement of waste in a CCR surface impoundment in cases where the CCR unit fails to meet the aquifer location restriction and in cases where a CCR unit demonstrates an exceedance of a groundwater protection standard. The regulatory deadlines that currently present a scenario that could trigger the closure of CEI South surface impoundments include exceedance of ground water protection standards (triggering closure in October 2020), or failure to demonstrate compliance with location restrictions (triggering closure in October 2020). Environmental groups challenged the final "Phase 1, Part 1" rule in the D.C. Circuit Court. Additionally, in August 2018, the D. C. Circuit Court issued a decision in USWAG v. EPA, finding that the administrative record showed that all unlined impoundments pose a reasonable probability of adverse effects to human health and the environment and must be required to close. EPA filed a motion to remand the Phase 1, Part 1 rule and is currently working on rulemakings to implement the D.C. Circuit's decision. The "Disposal of Coal Combustion Residuals from Electric Utilities; A Holistic Approach to Closure Part A: Deadline to Initiate Closure" rule is one of those rulemakings and was finalized in August 2020. It provided an option for utilities to submit a demonstration (application) by November 30, 2020 for surface impoundments to remain active beyond the current rule closure dates, however no longer than October 15, 2023. CEI South submitted demonstrations for both the A.B. Brown Ash Pond and the F.B. Culley East Ash Pond. The A.B. Brown demonstration has been conditionally approved. The alternative capacity project is currently underway at A.B. Brown and has been completed at F.B. Culley.

1.3.2.2 Retrofitting Culley 3 to Comply with ELG

In accordance with the order of the IURC in Cause No. 45052 approving the planned activities necessary to continue to operate Culley 3 in compliance with the ELG and CCR rules, the bottom ash system at F.B. Culley Unit 3 conversion to a dry system was completed in December 2020. The FGD system was converted to Zero Liquid Discharge ("ZLD") technology. That project was completed and in service on May 1, 2023. These two technologies make Culley Unit 3 fully compliant with the Effluent Limitation Guidelines ("ELG") rule and the NPDES permit requirements for Culley 3.

1.3.2.3 Closing Coal Ash Ponds

The West Ash Pond at F.B. Culley completed closure in December 2020. The closure design included the construction of a lined contact storm water pond, which receives contact storm water from various areas of the plant. The construction of this pond, along with the installation of the dry bottom ash and FGD ZLD technologies, along with the new lined pond currently under construction, will enable the upcoming required closure of the F.B. Culley East Ash Pond.

The A.B. Brown Ash Pond is also facing forced closure later this year. Plans are currently underway for the excavation of all material from the A.B. Brown ash pond, with a majority of the ash being sent for beneficial reuse. The project was approved in Cause No. 45280, and the ash removal of this pond is expected to take several years. New lined ponds are currently under construction and these ponds will receive waters that currently go to the ash pond but need to be re-routed for the pond closure.

The majority of the ash from the AB Brown ash pond will be sent to a facility that uses the ash to make Portland Cement. This project will take several years to totally remove all ash from the pond; however, once the closure begins the water in the pond will be drained down. There will be a small amount of ash in the pond that cannot be used for beneficial reuse, and it will be moved to an onsite landfill.

1.3.3 Electric Transmission Distribution Storage Improvement Charge

System improvements from CEI South's seven-year Transmission Distribution Storage Improvement Charge ("TDSIC") plan that have been made to build/rebuild high-voltage transmission lines, replace substation transformers, rebuild electric circuits, and build distribution automation will help CEI South to continue to reliably deliver power to its customers now and in the future. These improvements will allow more flexibility in resource planning by improving power flows across CEI South's system, particularly the addition of the East-West transmission line that connects the Warrick North substation site on the east side of the system with the A.B. Brown plant site on the west side. This project was energized on March 1, 2023. CEI South filed its second TDSIC plan on May 24, 2023, which outlines additional upgrades between 2024-2028[15]. An order is expected from the Commission by the end of the 2023.

1.3.3.1 Advanced Metering Infrastructure ("AMI")

In 2017, CEI South began installation of AMI smart meters as a key part of CEI South's grid modernization plan. CEI South has since successfully installed meters across its territory. AMI provides access to much more granular customer load data and will help CEI South to better understand and anticipate changes in an evolving energy landscape. This improvement will have long-term benefits for load research and long-term load forecasting, as well as provide the opportunity to create innovative DSM programs for shaping customer load. CEI South customers have already received many benefits in the near term for billing, quicker service response time, improved meter read accuracy, customer dashboards, proactive repairs reported by meter events, and quicker responses to power outages. CEI South has worked closely with its IT department to be able to pull customer demand data by rate class, starting with 2022, and now can segment on various customer groups. Over the next year, more tools will become available as CEI South's meter data management system is replaced with the meter data management system in Texas. At that time, CEI South will unlock more potential with out of the box applications

[15] Cause No. 45894

that have been created for the Houston territory. The ability to leverage functionality that has already been built will be a huge benefit to Southern Indiana; however, these long-term benefits have not been fully realized by the compilation of this IRP.

1.3.4 Inflation Reduction Act ("IRA")

The IRA was signed into law by President Biden on August 16, 2022. The timing of the IRA passage was fortunate, as it was in the early phase of this IRP and allowed for CEI South to quickly work to allow All-Source RFP bidders to resubmit their bids to incorporate the effects of the law change. The $500 billion bill aimed at reducing the effects of climate change included numerous incentives to promote investment in clean energy production and included tax credits for households to offset energy costs. Most of this spending is intended to reshape energy infrastructure. Major pieces of this bill that have helped shape this IRP include the extension of wind production tax credits, the allowance of solar production tax credits, the continuance of solar investment tax credits, funding for energy efficiency, the introduction of the ITC for stand-alone battery storage, and incentives for electric vehicle charging.

In addition to the base PTC and ITC there are several bonus adders and requirements that are possible to increase the value of these tax credits. The requirements or adders brought forward for projects under the new IRA include, but are not limited to, wage & apprenticeship requirements, domestic content minimums, siting in energy communities, and siting in low-income Communities or on Indian land. Since the passage of the IRA in August 2022, the IRS has been issuing clarifications and guidance on how projects can qualify for these adders. Since this is an ongoing process, CEI South included sensitivities to capture various uncertainties with future project tax credit qualifications.

1.3.5 DSM Filing

On June 3, 2020, CEI South filed with the IURC a Petition seeking approval of CEI South's 2021-2023 Energy Efficiency Plan ("2020-2023 Filed Plan" or "Plan"). The Plan included proposed energy efficiency goals; program budgets and costs; and procedures for independent Evaluation, Measurement and Verification ("EM&V") of programs included in the Plan. The Plan has an estimated cost of $34.2 million, with $11.5 million in 2021, $11.3 million in 2022 and $11.3 million in 2023. The Plan includes a portfolio of programs designed to achieve 132 million kWh in energy savings and 29,935 KW in demand reduction during the three-year period.

On October 20, 2020, CEI South filed a joint stipulation and settlement agreement between CEI South, the OUCC, and Citizens Action Coalition ("CAC"). On February 3, 2021, the IURC issued an Order approving CEI South's 2021-2023 Energy Efficiency Settlement Agreement ("2021-2023 Approved EE Plan") pursuant to Section 10. CEI South carried out a lengthy analysis of the DSM resources included in its IRP process. The Commission found that the proposed energy savings goals appear reasonably achievable and consistent with historical savings that has been previously approved. A summary of the savings and budgets are listed in the table below.

Figure 1.2 – 2021-2023 Portfolio Summary of Participation, Impacts, & Budget

Portfolio Participation, Impacts & Budget[16]							
Program Year	Participants / Measures	Annual Energy Savings kWh	Annual Demand Savings kW	Res & C&I Direct Program Budget	Indirect Portfolio Level Budget	Other Costs Budget	Portfolio Total Budget Including Indirect & Other
2021	235,332	44,325,438	10,061	$10,061,209	$1,046,819	$400,000	$11,508,027
2022	225,146	43,961,753	9,571	$10,092,043	$1,051,408	$200,000	$11,343,451
2023	218,863	43,533,925	10,303	$10,073,357	$1,061,922	$200,000	$11,335,280

1.3.6 2019 IRP Director's Report

Each year, the Director of Research Policy and Planning in the IURC electric division issues a critique of IRPs. The 2019 IRP Director's report listed a balance of positive comments, coupled with improvement opportunities for CEI South. The table below shows the improvement opportunities with a brief description of how the comment was addressed within the 2022/2023 IRP:

[16] Cost per kWh excludes indirect and other costs for budget. Cost per kWh is calculated by dividing program cost by total savings and do not include carry forward costs related to smart thermostat, BYOT and CVR programs.

Figure 1.3 – IRP Improvements Based on 2019 IRP Director's Report[17]

Improvement Opportunities	Addressed
Break out energy efficiency bundles into C&I and residential bundles	CEI South broke out energy efficiency bundles into C&I and residential and worked closely with stakeholders to evaluate and apply the maximum amount of EE to be economically selected within modeling. Residential bundles were grouped according to high and low/medium costs so as not to exclude all residential from not being selected. C&I bundles included an enhanced bundle to optimize the selection of EE above realistic achievable potential. Stakeholder feedback was included and helped guide bundle development.
Future requests for proposal should consider all DER opportunities	DERs were able to participate in the RFP utilized for this IRP. As a result of opening the All-Source RFP more and based on stakeholder feedback, CEI South is actively engaged with a DR aggregator to explore the market potential of the Evansville area for C&I DR and to partner to tap into this market as a future resource.
One optimization run with a minimum number of constraints	During the IRP process, the Reference Case Portfolio was determined by an optimization run in EnCompass that included as few constraints as possible around resource selection. This allowed the model to run in an unconstrained way selecting the portfolio by determining tradeoffs between existing resource options and new resource selections.

[17] The director provided guidance on page 13 of the Director's Report for Vectren's 2019/2020 IRP on November 17, 2021, to consider sub-hourly modeling to capture value of ancillary services. Currently ancillary services provide a very small piece of revenue potential, and it is extremely difficult to accurately project the value in the future. The added complexity was not deemed necessary when compared to the value that the complex analysis would provide. CEI South will continue to monitor the need for this level of detail in the future as computer processing speeds increase. https://www.in.gov/iurc/files/Vectrens-Final-Directors-Report-November-17.pdf

1.3.7 HB 1007

On April 20, 2023 the Governor Holcomb signed HB 1007 into law; it becomes effective on July 1, 2023. The law requires decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs to take into account the following attributes: Reliability, Affordability, Resiliency, Stability, and Environmental Sustainability. These attributes must be considered within the Directors' report for an IRP submitted by an electric utility. The IURC must also consider these attributes when acting upon a petition for the construction, purchase or lease of an electric generation facility, and when the IURC reviews whether a CPCN continues to require the completion of an electric generation facility under construction. As such, the law will help continue to shape Indiana's energy future. Importantly, the bill further reduces a utility's reliance on MISO's planning resource auction from 30% to 15% of its accredited capacity in the summer and winter. This was a major consideration within this IRP.

1.3.8 COVID-19

By the spring of 2020, Indiana, like many other states across the country, issued a "Stay at Home" order in response to the COVID-19 virus. This had the impact of significantly reducing commercial and industrial usage as businesses shutdown and residential usage significantly increased as work activity shifted from the office to the home. As these restrictions were lifted most businesses re-opened, although even today some portion of the workforce remains working from home. To capture the impact, the residential average use and non-residential rate class models include a COVID impact variable. This variable is constructed using Google Mobility Report data for the residential, workplace and retail place types for Vanderburgh County. Google Mobility Report data tracks daily cell phone locations by place type compared to a pre-COVID baseline. The residential place type active increased while the workplace and retail decreased, this data correlates well to the actual changes in electric sales.

1.3.9 Contemporary Issues

CEI South participates in the Commission's IRP Contemporary Issues Technical Conference held each year. The most recent Conference was held on September 22, 2022. The Conference covered topics such as MISO's new seasonal resource adequacy construct, PJM's resource adequacy model, the continued evolution of their resource mix and emerging reliability risks, and how reliability planning is evolving.

Several of these topics were timely and influential within CEI South's analysis. For example, the MISO seasonal construct presentation discussed priority system attributes needed to maintain system reliability. These attributes included long duration energy at high output, ramp capability, and fuel assurance, all of which are included in CEI South's preferred portfolio.

CEI South also participated in the IRP Contemporary Issues Technical Conference on July 15, 2021. During the conference GDS, our Market Potential Study ("MPS") partner, talked about similarities and differences in the market potential studies GDS conducted on behalf of the several Investor Owned Utilities ("IOU") in Indiana. It covered differences in how the load forecast is used in the MPS, how avoided costs and line loss assumptions were included in the analysis, the availability of market and measure characteristic data, inclusion of emerging tech and measure refill, and measure mapping to existing programs. GDS also touched on using the MPS to provide inputs into the IRP. CEI South also had internal staff speak to the role of Energy Efficiency Oversight Board in the development of IRP inputs, monitoring DSM program performance and how the OSB works collaboratively to provide input into measures offered, program design, and utilization of approved program dollars to achieve portfolio goals.

The discussion relating to All-Source RFPs during the September 24, 2020, Technical Conference was also beneficial as CEI South issued another All-Source RFP on May 11, 2022 to support this IRP analysis. CEI South engaged 1898 & Co., a subsidiary of Burns and McDonnell, to administer the RFP and serve as an independent evaluator. The All-

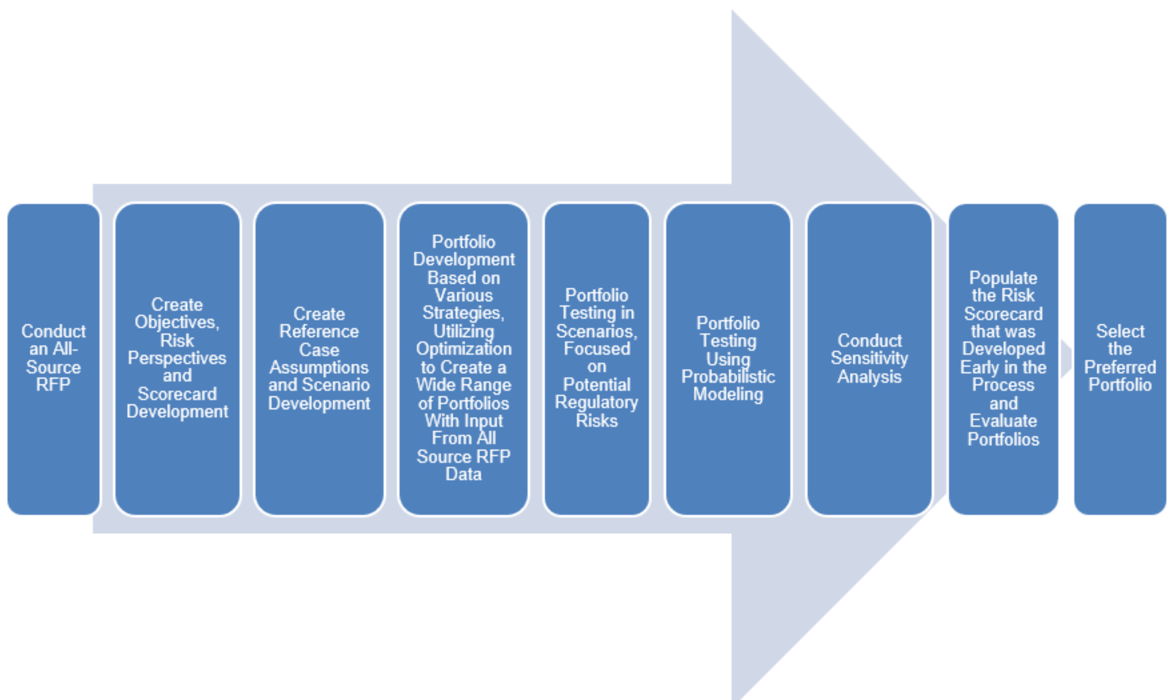
Source RFP was structured to be open and non-limiting and resulted in proposals largely comprised of solar, wind, battery storage, and Load Modifying Resource ("LMR")/DR resources. The All-Source RFP is discussed in further detail in sections 3 and 6 of this report.

SECTION 2
CEI SOUTH'S IRP PROCESS

2.1 CEI SOUTH'S IRP PROCESS

CEI South's 2022/2023 IRP followed a very structured, comprehensive process over a 15-month period with extensive risk-based analysis and included an All-Source RFP to include market-based pricing with the opportunity to secure available resources following the conclusion of the IRP. This process was designed to ensure relevant technologies were evaluated and the resulting portfolio combinations were tested in a wide range of future market and regulatory conditions. The process followed is illustrated below.

Figure 2.1 – CEI South IRP Process



The following sections describe each step in the analysis.

2.2 Conduct an All-Source RFP

CEI South issued an All-Source Request for Proposals ("RFP") seeking power supply and demand-side Proposals for capacity and unit-contingent energy to meet the needs of its customers. Long term resource planning requires addressing risks and uncertainties created by several factors including the costs associated with new resources. As part of ongoing resource planning, CEI South concluded that it was in the best interest of its customers to seek information regarding the potential to acquire, construct, or contract for additional capacity that qualifies as a MISO internal resource (i.e., not pseudo-tied into MISO) with physical deliverability utilizing Network Resource Integration Service ("NRIS") to MISO LRZ 6. These requirements helped to provide price certainty, transparency, and MISO Local Clearing Requirement ("LCR") accreditation, which will be discussed in further detail.

Within the context of the 2022/2023 IRP process, CEI South used an All-Source RFP to solicit bids for supply-side and demand-side capacity resources. The purpose of the RFP was to identify viable resources available to CEI South in the marketplace to meet the needs of its customers. Dependent upon further evaluation of aging resources and prior to the 2022/2023 IRP, there was a potential capacity need of approximately 500 MW of accredited capacity depending on the different portfolios being studied as part of the IRP. CEI South sought flexibility when defining potential resource combinations and encouraged RFP respondents to offer available projects with less than, or more than, 500 MW. CEI South also considered alternative timelines related to the capacity acquisition to the extent Respondents were able to provide more competitive pricing and/or terms for delivery if the resource was in service or operational prior to 3/1/2027. CEI South used aggregated data from the RFP responses as inputs into the IRP modeling. The RFP Proposal evaluation process was based upon the specific resource needs identified through this IRP modeling as well as the Proposal evaluation criteria. Through this RFP, CEI South sought to satisfy the identified capacity need through either a single resource or multiple resources including dispatchable generation, LMRs/DRs, renewables, stand-alone and paired storage, and contractual arrangements.

In connection with this RFP, CEI South retained the services of an independent third-party consultant, 1898 & Co., part of Burns & McDonnell, to manage the entire RFP process and work with CEI South to perform the quantitative and qualitative evaluations of all Proposals.

All Respondents were directed to interface with 1898 & Co. for all communications including questions, RFP clarification issues and RFP Proposal submittal until late in the evaluation process.

Proposals were initially reviewed for completeness by 1898 & Co. Respondents were contacted for additional data or clarifications by 1898 & Co. via a designated CEI South RFP e-mail address, centerpointrfp@1898andco.com. Each complete Proposal was evaluated based on the Levelized Cost of Energy ("LCOE"), energy settlement location, interconnection/development status & local clearing requirement and project risk factors. The evaluation criteria were intended to relatively compare each Proposal to analogous submissions. This evaluation, in conjunction with the IRP, was used to determine which combination of resources are most capable of providing CEI South customers with a safe, reliable, and affordable power supply.

2.3 OBJECTIVES, RISK PERSPECTIVES and SCORECARD DEVELOPMENT

CEI South's IRP process is designed to ensure a systematic and comprehensive planning analysis to determine the "preferred portfolio" that best meets all its objectives over a wide range of market futures. This process results in a reliable and efficient approach to securing future resources to meet the energy needs for CEI South customers.

In addition, the IRP process complies with environmental regulations and reliability requirements, while reducing its vulnerability to market and regulatory risks, the risk of supply disruptions. In the IRP, CEI South also focused on increasing the diversification of its supply sources. As part of the IRP, CEI South considered maintaining flexibility to respond to market changes. The evaluation considered both existing and new resources, including renewable energy and battery storage options.

Economic modeling is an important part of the IRP process, as it allows CEI South to identify the portfolio of supply-side and demand-side resources on a competitive economic basis. The resulting portfolios reflect a combination of market, regulatory or technology specified conditions and market input parameters (for example, identify the least cost portfolio consisting of mostly renewables and battery storage by 2030 using reference case market forecasts). While cost is an important objective, it is by no means the only objective. CEI South has several important objectives, each of which needs to be considered when evaluating the best portfolio for its stakeholders over time. Moreover, CEI South needs to account for operational and logistical considerations in the construction of alternative portfolios to ensure that they meet minimum reliability or resource adequacy considerations.

CEI South's IRP strategy is designed to accommodate ongoing changes and uncertainties in the market. CEI South's IRP objectives are based on the need for a resource strategy that provides long-term value to its customers and communities. Therefore, as objectives are evaluated, tradeoffs must be considered. Specifically, CEI South's IRP objectives are as follows:

- Reliability: As new technologies proliferate and older baseload units retire, it is apparent that there will be increased reliance on intermittent, renewable energy resources. The ability to support local system stability and reliably provide power must be maintained by meeting MISO and North American Electric Reliability Council ("NERC") standards for reserve margins and resource adequacy.

Quantitative Metrics Directly Considered

- **Affordability:** Provide all customers with an affordable supply of energy
- **Cost Uncertainty Risk Mitigation:** Provide a predictable, balanced, and diverse mix of energy resources designed to help ensure costs do not vary greatly across alternative future market conditions or supply disruptions.

- **Environmental Sustainability:** Provide environmentally responsible power, leading to a low carbon future with fewer impacts to air and water quality and less waste generated.
- **Market Risk Minimization:** Develop a flexible plan that can adapt to market conditions and regulatory and technological change to minimize risk to CEI South customers and shareholders. The plan considers several alternative options for existing resources.

  Other Considerations
- **Execution:** Assess challenges with implementing the determined plan.
- **Resource Diversity:** Mitigate risk to customers of over-reliance on a single technology by providing a resource mix to minimize the dependence on any one resource type that could become operationally or economically eclipsed.
- **System Flexibility:** Operationally able to meet the current and future needs of the evolving grid.
- **Resilience:** A portfolios ability to recover from off normal events, like extreme/long duration weather events.
- **Stability:** The ability of a portfolio to maintain system frequency and voltage, thermal limits, and power transfer capability.

Reliability is CEI South's priority over all other objectives. All portfolios must meet minimum reserve margin and resource adequacy requirements set by MISO. These are minimum requirements met in the modeling rather than a single metric tracked for each portfolio. CEI South did a reliability assessment to identify mitigations needed for stability for several portfolios represented options that made it through the screening process. This is described in Section 6.4.3 Transmission Facilities as a Resource.

The next several objectives are given one or more defined and measurable metrics. By testing candidate portfolios against these metrics, CEI South illustrates tradeoffs among competing IRP objectives. This tool aided in the selection of the preferred portfolio. The last five objectives are more subjective in nature but relevant to the IRP process so are discussed under "other considerations".

Figure 2.2 – CEI South Scorecard for IRP Objectives and Risk Metrics

	Objective	Metric
Quantitative and Qualitative (considered outside of scorecard)	Reliability	• Must meet MISO planning reserve margin requirement in all seasons • Spinning reserve and fast start capability
Quantitative Scorecard Measure	Affordability	• Mean value for the 20-Year Net Present Value of Revenue Requirements ("NPVRR") (million$) across 200 dispatch iterations under varying market conditions
	Cost Uncertainty Risk Minimization	• 95th percentile[18] of NPVRR (million$) across 200 dispatch iterations under varying market conditions • Portion of energy generated by resources with exposure to coal and gas markets
	Environmental Sustainability	• CO_2 Intensity (Tons CO_2e/kwh) • CO_2 equivalent emissions (Tons CO_2e)
	Market Risk Minimization	• Energy Market Purchase and sales (%) • Capacity Market purchases and sales (%)
Qualitative (considered outside of scorecard)	Execution	• Assess challenges of implementing each portfolio
	Resiliency	• Assess the ability of a portfolio can recover from off normal events, like extreme/long duration weather
	Stability	• Assess ability of the portfolio to help maintain system frequency and voltage, thermal limits, and power transfer capability
	Resource Diversity	• No over reliance on any one resource or resource type
	System Flexibility	• Operationally able to meet the current and future needs of the evolving grid

[18] 95th percentile means that there is a 95% chance the cost falls below this level (only 5% chance above). Price Risk Minimization represents the upper end cost potential for the portfolio

Defined metrics are used to evaluate different portfolios and planning strategies in the IRP process. These metrics provide objective assessments of critical factors of each portfolio under different market scenarios. There are natural trade-offs among these objectives; for example, the portfolio with low expected costs may increase exposure to market risk. The objective of the IRP is to find the right balance of these metrics across a wide variety of future conditions to help ensure that the ultimate choice of a portfolio performs well, regardless of the circumstances. Portfolio selection is based on CEI South evaluating all qualitative and quantitative metrics and using well-informed judgement in selecting its preferred portfolio. A further description of each metric is provided below.

2.3.1 Objectives and Risk Perspectives

The IRP objectives were evaluated using the results of the scenario, sensitivity, and probabilistic modeling, as well as other qualitative factors.

2.3.2 Scorecard Metrics

The Balanced Scorecard is a broad comparison of candidate portfolio attributes and risks. It was populated with metrics nearly all derived from the probabilistic modeling. The probabilistic modeling subjected each portfolio to 200 iterations of the dispatch model under varying market conditions. CEI South then used the resulting performance data and the distributions from the 200 iterations to quantify the metrics that align with each IRP objective. The Balanced Scorecard metrics are the same as the risk metrics described in Figure 2.2.

2.3.2.1 Reliability

The ongoing energy transition is transforming the way IRPs are conducted, further emphasizing reliability considerations within an IRP process. As a member of MISO, CEI Couth is not independently responsible for all elements of reliability but must be prepared to meet changing market rules and standards. MISO has been studying the impacts of growing intermittent generation penetration in the market for the last several years, and where possible CEI South has incorporated those elements into the IRP. CEI South ensured all portfolios considered within the risk analysis of this IRP met expected planning reserve margin requirements in all seasons to help ensure sufficient resources are available to reliably serve demand and provide energy in all operating hours continuously throughout the year. Within the Reliability and Market Risk objectives in the scorecard, CEI South included metrics showing reliance on the capacity and energy markets, the amount of resources with fast start capability, and the amount of dispatchable resources with spinning reserve capability. Additionally, CEI South performed transmission planning analyses to consider voltage and reactive power support for various portfolios.

2.3.2.2 Affordability

For the Affordability objective, the metric used is the mean value for the 20-Year Net Present Value of Revenue Requirements (“NPVRR”), expressed in millions of dollars. The NPVRR is a measure of all generation related costs (for each asset, the cost of generation – capital, O&M, fuel and the cost of power and capacity purchases etc.) associated with the portfolio of assets over time. These costs are adjusted through a discount rate to ensure future costs are reflected in present year dollars, commonly known as a time value of money adjustment. In this way, very different portfolios can be compared on a common metric or value over a long-time frame.

2.3.2.3 Cost Uncertainty Risk Mitigation

For the Cost Uncertainty Risk Mitigation objective, the metric used is the 95th percentile of NPVRR, also expressed in millions of dollars. After each portfolio was subjected to 200 dispatch model runs, a distribution is created of the NPVRR portfolio costs. The 95th percentile (approximately two standard deviations above the mean value) is a commonly used benchmark to demonstrate a reasonable upper threshold of cost risk under widely varying market circumstances. In addition, per stakeholder request, the portion of energy generation with exposure to coal and gas markets gives further insight to risks posed by commodity markets and potential future regulatory requirements. This metric, expressed as a percentage, is the generation from coal and gas divided by the total fleet generation across 200 iterations.

2.3.2.4 Environmental Sustainability

For the Environmental Sustainability objective, the metric estimated CO_2 intensity and per stakeholder request CO_2 equivalent stack emissions were calculated. In addition to carbon dioxide, methane and nitrous oxide emission factors for coal (bituminous) and natural gas were taken from Table C-1 to Subpart C to 40 Code of Federal Regulations part 98 December 9, 2016. Chemical-specific Global Warming Potentials ("GWPs") were taken from table A-1 to 40 Code of Federal Regulations part 98 Subpart A for a 200 year time horizon December 11, 2014.

Figure 2.3 – Emissions factors used to Convert CO_2 to CO_2e by Resource

Coal Emission Factors (kg/MMBtu)	
CH_4 Conversion factor	0.011
N_2O Conversion factor	0.0016

Natural Gas (NG) Emission Factors (kg/MMBtu)	
CH_4 Conversion factor	0.001
N_2O Conversion factor	0.0001

Global Warming Potential	
CH_4	25
N_2O	298

Tons to kg conversion	
kg	Metric Tons
1	0.001

Outside of the scorecard, CEI South considered direct portfolio emissions reductions for each portfolio compared to a base year (2005) of power generation and resulting CO_2 emissions. The 2005 benchmark year saw 9,634,957 short tons of CO_2 emissions.

2.3.2.5 Market Overreliance Risk Minimization

For the Market Overreliance Risk Minimization objective, there were two metrics. There is the average annual energy sales and the average annual energy purchases, each divided by average annual generation and expressed as a percentage. There is also the average annual capacity sales and the average annual capacity purchases, divided by average coincident peak demand and expressed as a percentage.

Other Considerations

2.3.2.6 Resource Diversity

CEI South believes resource diversity helps minimize risk to customers by providing a mix of resources to minimize the dependence on any one resource type that could become operationally or economically eclipsed. CEI South's coal units have served its customers well over the years, but there continues to be pressure on this resource from evolving environmental regulations. F.B. Culley 3 continues to operate efficiently but will continue to be challenged to meet increasingly more stringent air regulations in the short and long term. A recent example is the passage of the Good Neighbor Rule, which ratchets down emissions standards across the country. While it does not change FB Culley 3's current operating thresholds beyond those required in the recently finalized CSAPR update, compliance with these ever evolving emission targets as described in 1.3.2.1.1 will likely be more difficult and costly in the future. The IURC reinforced this consideration that CEI South should consider resource diversity and alternatives that provide off ramps that allow CEI South to react to changing circumstances.

While very important, it is hard to create a measure that adequately captures this value. Instead, CEI South sought to develop portfolios that included a wide range of resource types and fuel sources. To ensure this objective has been met, CEI South built portfolios that ensure diverse mixes. CEI South included an All-Source RFP to fully consider renewable and battery storage resources within all portfolios.

2.3.2.7 System Flexibility

System flexibility was an important consideration in the 2022/2023 IRP. As intermittent renewable resources continue to grow on the transmission and distribution system, it is important to back these resources up for reliability and resilience. As such, CEI South considered performance of resources with the ability to start and ramp quickly and be available for sustained periods in times when the sun is not shining, and the wind is not blowing. CEI South also considers the transmission system and the ability to rely on the market as an important consideration in IRP planning. While CEI South has considerable import capabilities with the addition of the Duff Coleman Market Efficiency transmission Project ("MEP") and the recently energized East/West line, this capability is not unlimited and requires needed upgrades to maintain reliability for portfolios that rely less on traditional dispatchable energy resources. All portfolios include the recently approved natural gas CTs at A.B. Brown, which provide quick start, fast ramping capabilities.

2.3.2.8 Resilience

Resilience is the ability of a portfolio to recover from off normal events, like extreme/long duration weather events. With shrinking reserve margins in MISO and the recent, more frequent weather events, resilience has become an important consideration within the IRP. The state of Indiana recently included resilience as one of the five pillars in HB 1007. As such, all portfolios with new gas resources included costs for firm gas supply.

2.3.2.9 Stability

Stability is also one of the five pillars in HB 10007. It is the ability of the portfolio to help maintain system frequency and voltage, thermal limits, and power transfer capability. A portfolio must provide these essential functions. For more information, please see section 6.4.3 Transmission Facilities as a Resource for a description of CEI South's analysis and conclusions relating to this objective.

2.4 REFERENCE CASE ASSUMPTIONS AND BOUNDARY SCENARIOS

After selecting the objectives and metrics, the next step in the process was to define the scenarios for consideration in the selection of alternative portfolios. In this case CEI South selected a Reference Case and four alternative scenarios for two purposes. The first purpose was to create a least cost portfolio for each of the five scenarios and the second was to test final portfolios against each of the market scenarios to determine how well they perform. Below is a brief discussion of each. Greater detail is provided in Section 7 which identifies the key inputs for each scenario.

2.4.1 Reference Case

The Reference Case scenario represents the most likely future conditions. CEI South surveyed and incorporated a wide array of third-party sources to develop its Reference Case assumptions, several of which reflect a current consensus view of key drivers in power and fuel markets. Reference Case assumptions include forecasts of the following key drivers:

- Henry Hub and delivered natural gas prices
- Illinois Basin mine and delivered coal prices
- MISO Capacity Cost
- CO_2 ACE Proxy
- Capital costs for various generation technologies
- Load forecast

The long-term energy and demand forecast for the CEI South service territory was developed for CEI South by Itron, a leading forecasting consultant in the U.S. The forecast is based on historical residential, general service (commercial) and large (primarily industrial) usage and drivers such as appliance saturation and efficiency projections, electric price, long-term weather trends, customer-owned generation, electric vehicle adoption and several demographic and economic factors.

For natural gas, coal, and capacity price, CEI South used a "consensus" Reference Case view of expected prices by averaging forecasts from several sources. This helps to ensure multiple views are considered and allows CEI South to be transparent with modeling assumptions. For natural gas and coal, 2022 fall forecasts from S&P, Wood Mackenzie, ABB, and EVA were averaged. The capacity price forecast was based on MISO Zone 6 forecasts from ABB and S&P. Note that seasonal capacity forecasts were not available at the time of this IRP. Those used were the best available information at the time. No CO_2 price was included in the Reference case. Rather costs were included for efficiency upgrades.

All-Source RFP bids were utilized for resource cost information between 2024 and 2042, where possible. Long-term cost curve information was developed by applying the National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") curve to more recent market based cost assumptions. The 1898 and Co. technology assessment helped fill in the gaps with operational data and for various technologies, including gas and coal resources.

CEI South worked with stakeholders and GDS to develop a Market Potential Study ("MPS") for demand side resources. This study was used to create demand side inputs to be compared on a consistent and comparable basis with supply side resources.

1898 & Co. developed power price forecasts used for the Reference Case and the Alternative Scenarios using an EnCompass database and updating the commodity inputs and model assumptions associated with each of the unique scenarios. EnCompass was then used by 1898 & Co. to develop an optimized, least-cost portfolio for the Reference Case, which was then run in chronological hourly dispatch mode. These key drivers constitute the Reference Case assumptions. More information on modeling inputs can be found in Section 7.2 Reference Case Scenario.

2.4.2 Alternative Scenarios

It is important to test technologies against a variety of future market conditions, not just the Reference Case. Hence, CEI South, with the support of 1898 & Co., selected four alternative scenarios (Market Drive Innovation, High Regulatory, Continued High Inflation and Supply Chain Issues and Decarbonization/Electrification) to provide boundary conditions for testing the technologies and developing portfolios that could be subjected to a full risk assessment (with hundreds of scenarios tested later in the process).

CEI South worked with 1898 & Co. and received input from CEI South stakeholders on key inputs such as load forecasts, gas and coal prices, carbon emission prices and technology capital costs. With input from stakeholders, CEI South and 1898 & Co. determined whether gas prices, coal prices, load, technology capital costs, carbon emission prices and power prices would move up or down relative to the Reference Case under each of those scenarios. This process was followed to illustrate what might happen under each of these scenarios in a consistent manner with the risk analysis. Below is an illustrative description of each scenario.

- High Regulatory – The High Regulatory scenario depicts a future of higher regulation resulting in higher costs of energy and some resulting economic slowdown. A high carbon fee is implemented throughout the planning horizon (2023 - 2042). A fracking ban is imposed, driving up the cost of natural gas notably in the long-term as supply dramatically shrinks. Declining demand for coal is offset by regulations that increase the coal price resulting in coal prices higher than the Reference Case as coal mines close and remaining coal producers can charge more per ton, passing costs of new regulations on to remaining customers. Although technological innovation is stifled, renewables and battery storage receive government incentives, allowing costs to fall even as demand for these technologies increases. Utility-sponsored energy efficiency costs rise over time as the cost for regulatory compliance rises.

- Market Driven Innovation – A transition to a more free market leads to new and advanced technology, driving down energy prices. Less government influence drives competition among competing fuels and no carbon tax results in lower power prices from natural gas and coal resources. Increased energy usage is a direct result of less government influence reducing overall costs. Further technological innovation to lower energy cost is spurred by an increase in demand for renewable and storage resource options. This advancement in technological innovation drives more opportunities for energy efficiency programs. Energy efficiency programs are predicted to be more cost effective with increased load. In addition, less codes and standards changes allow utility sponsored energy efficiency programs to transform the market at a lower incentive cost.
- Decarbonization/Electrification – Utility-sponsored energy efficiency costs are below base levels due to technology advances, allowing for new and innovative ways to partner with customers to save energy. As technology costs fall, customers begin to move towards electrification, driving more electric vehicles and higher adoption of rooftop solar/energy storage and trend towards highly efficient electric heat pumps in new homes and other buildings. The switch to electrification causes an increase in load and natural gas supply; however, the natural gas prices remain at Reference Case level due to methane regulations. A mid-level carbon tax is imposed causing demand for coal to decrease and supply constraints cause coal prices to increase. Technological improvements to lower costs are offset by higher demand and rising land and labor costs.
- Continued High Inflation & Supply Chain Issues – With a shortage in labor and materials, costs for new technologies and fuels increases. Higher labor and delivery costs reduced the supply of fuel leading to higher coal and natural gas prices. Load demand is negatively affected by high inflation causing reduced economic output. Like the Reference Case, no carbon price is imposed. Continued disruptions in the supply chain along with high inflation leads to higher costs for renewables and storage. Reduction in load results in less potential of energy

efficiency acquisition both for incentives passed to customers and implementation of programs as implementers experience increased cost. In addition, shortage of EE equipment leads to increased cost of high-efficient measures.

A summary of the relative outlooks for key market drivers across the scenarios considered is presented in Figure 2.4.

Figure 2.4 – Summary of Directional Relationships of Key Inputs Across Scenarios

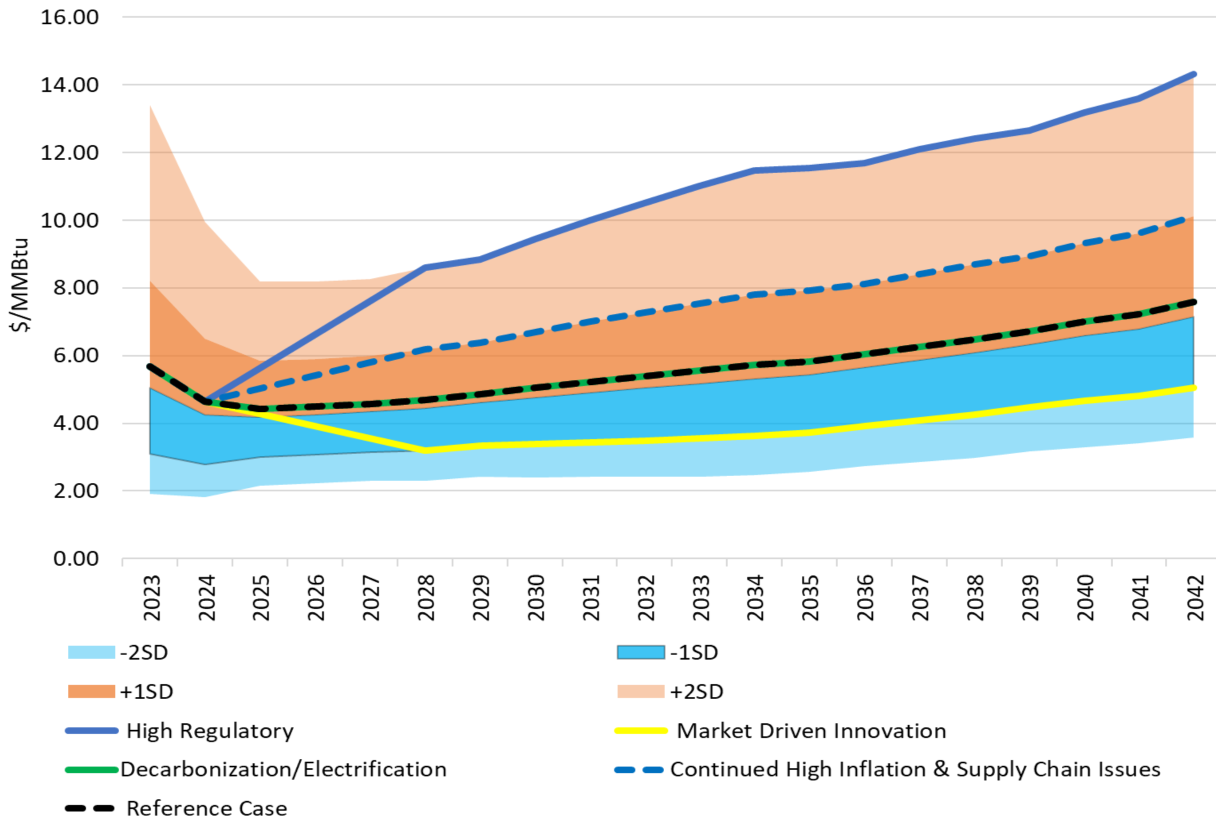
	CO_2	Gas Regulation	Other Environmental Regulations	Economy	Load	Natural Gas Price	Coal Price	Renewables and Storage Cost	EE Cost[19]
Reference Case	ACE Proxy	None	None	Base	Base	Base	Base	Base	Base
High Regulatory	Highest	Fracking Ban	MATS Update	Lower	Lower	Highest (+2 SD)	Higher	Lower	Higher
Market Driven Innovation	Base	None	None	Higher	Higher	Lower	Lower	Lower	Lower
Decarbonization/ Electrification	High	Methane	None	Base	Higher	Base	Higher	Base	Lower
Continued High Inflation & Supply Chain Issues	Base	None	None	Lower	Lower	Higher	Higher	Higher	Higher

Using the Reference Case as a consistent starting point, the boundary scenarios were developed. Key variables are assumed to remain the same as the Reference Case in the short-term (2022-2024). To the extent key variables differ from Reference Case value, they will vary by plus or minus one or two standard deviations (“SD”). The SDs were developed as part of the stochastic variable process described in Technical Appendix 11.6. In the medium-term (2024-2028), key variables grow or decline to +/-1SD or (+/-2SD) by 2028 (midpoint of medium-term) as shown in the table above. After 2028, the variable stays at +/-1SD (or +/-2SD) into the long-term to 2042. Because this price path remains at the one (or two) SD(s) path for the entire planning horizon, these levels have

[19] EE costs were not varied by scenario within IRP modeling. Rather, CEI South worked closely with stakeholders to maximize the amount of energy efficiency to be selected. This process was done in lieu of varying price by scenario.

a low probability and are viewed as very wide. The five scenarios were designed to be consistent with the stochastic distributions (200 iterations) developed for the risk analysis, but on a much more limited scale (five scenarios). An illustration of this methodology for natural gas prices is presented in Figure 2.5.

Figure 2.5 – Henry Hub Natural Gas Price Scenarios ($/MMBtu)



Under all scenarios Henry Hub gas prices begin at $5.68/MMBtu in 2023 and continue declining until hitting $4.65/MMBtu in 2024. After this time, the Reference Case gas prices gradually trend upward to $7.59/MMBtu in 2042. Gas prices in the other scenarios either follow the Reference Case or trend higher or lower, depending on the scenario's coordinated input direction. Gas prices in the High Regulatory scenario are designed to reach the +2 SD level to replicate the price impact of a hydraulic fracturing ban, which would greatly limit domestic production, increase costs and put upward pressure on prices. The Market Driven Innovation scenario sees natural gas prices moving downward to -1 standard deviation below the Reference Case.

The convention of +/-1 or +/-2 SDs is used to maintain a consistent methodology and result when moving key market drivers up or down in each of the scenarios. It should be noted that the historical price distributions differ among the various market drivers are not necessarily symmetrical (i.e., normally distributed). For example, gas prices are positively skewed because they have no upper boundary and can reach many SDs above the historical average, whereas they typically cannot fall below zero (or approximately two SDs below the historical average).

The graphical descriptions of values for each of the key metrics (e.g., load, gas prices, coal prices, and technology costs) are shown in Section 7.3.2.2.

2.5 PORTFOLIO DEVELOPMENT

The portfolio development process was designed to test a wide range of technology options. An exhaustive list of technology options was developed and then refined. The viability of existing resources was considered as well as new resources including demand side measures of varying sizes and timeframes. The wide range of portfolio strategies was informed by stakeholder feedback as well as the All-Source RFP.

An All-Source RFP was issued at the onset of the IRP process to obtain actual market information for near term indicative pricing for a wide range of technologies. The average delivered cost by resource informed the modeling and portfolio options. This included new builds, power purchase agreements, demand response and other supply options. The results of the All-Source RFP were vetted by 1898 & Co. and ultimately converted into model inputs.

An 1898 & Co. technology assessment defined the list of technologies and provided cost and performance information for resources. Where possible, technology costs from the

All-Source RFP bids were utilized. Long-term cost projections started at prices received as part of the RFP and trended over time based on NREL projections. A total of 30 resource options for power supply were included in the analysis. These included wind with and without storage, solar with and without storage, hydroelectric, several battery storage options, simple cycle and combined cycle natural gas and natural gas fired combined heat and power technologies. Two new coal-fired technologies were included, both of which were assumed to be equipped with carbon capture and storage. Site specific studies were also conducted to provide cost and performance information for conversion options at A.B. Brown and F.B. Culley plants.

Long Term Capacity Expansion ("LTCE") Assessments

The EnCompass model was used as the central tool in the IRP to develop the 9 candidate portfolios in addition to the Reference Case portfolio. The long-term capacity expansion functionality within EnCompass was used to help develop portfolios based on the given sets of market input assumptions and portfolio requirements. This includes decisions to build, purchase, or retire plants.

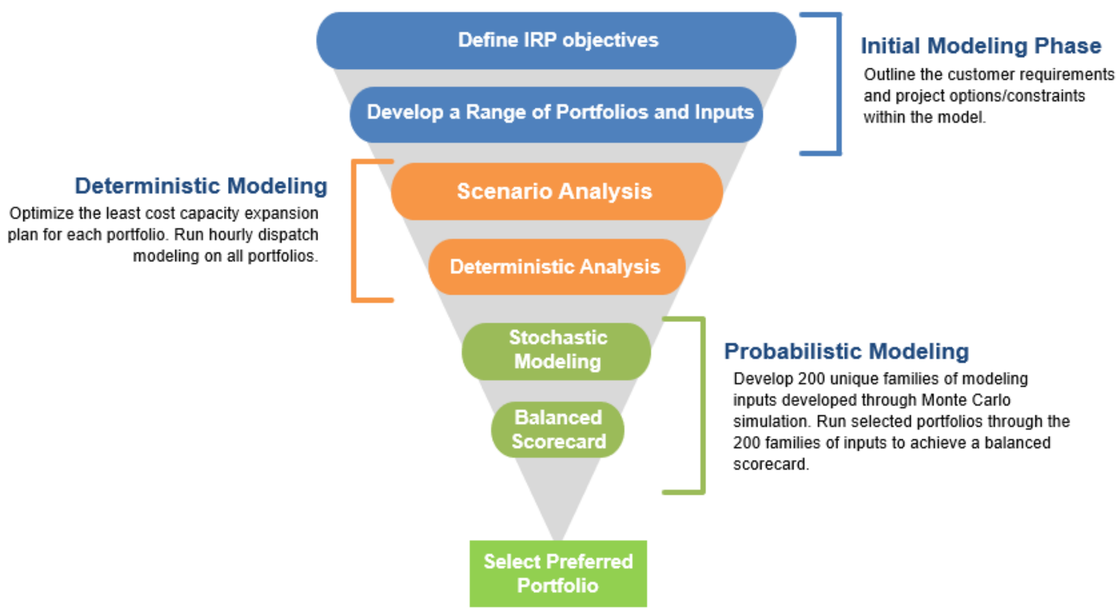
Market transactions offer supply flexibility but also exposure to potential market risk to CEI South customers. In addition to the supply and demand side resource alternatives, portfolios were able to select market supply options as well. To reduce the risk that comes from exposure to the market, a limit of 50 MWs of market capacity purchases was imposed beginning in 2029. Recent legislation was passed in Indiana, capping the reliance on MISO's planning resource auction at 15%. This limit helps to ensure portfolios do not overly rely on capacity purchases in the long term. There is more certainty in the near term about what might be available through bi-lateral contracts. As such, early years included higher thresholds of 300 MWs through 2025 and 180 MWs 2026-2028.

Portfolios were developed utilizing EnCompass modeling for the Reference Case, the alternate scenarios, and additional portfolios developed based on stakeholder feedback. The model uses hourly chronological dispatch over a 20-year period, which means outcomes are based on all 8,760 hours each year over a 20-year span. This helped to better evaluate intermittent renewable and storage resources.

Figure 2.6

illustrates the portfolio screening process applied in the analysis to select the preferred portfolio. In addition to the scenario-based portfolios, CEI South and 1898 & Co developed many additional portfolios to ensure a wide range of technologies were assessed and influenced by stakeholder input to specifically evaluate alternate resource strategies. The refinement for each portfolio, whether it be a modification to an existing unit or requiring the addition of renewables was required as part of a portfolio and then the model selected the remainder of the portfolio on a least cost basis. Once the reference case, scenario-based portfolios, and additional deterministic portfolios were analyzed, CEI South was able to screen out costly, overlapping, or overbuilt portfolios.

Figure 2.6 – Structured Portfolio Selection Process



As described in Section 8, CEI South selected the reference case and the following nine portfolios for evaluation in the risk analysis. The selection criteria for eliminating the other portfolios are provided in that section.

1. Business as usual to 2042 including the continued operation of FB Culley 3 continues through study period;
2. Convert FB Culley 3 to natural gas in 2027;
3. Convert FB Culley 3 to natural gas in 2027 with wind and solar added in the same year;
4. Convert FB Culley 3 to natural gas in 2030;
5. Diversified Renewables;
6. Diversified Renewables with early storage and Distributed Generation solar;
7. Replace FB Culley 3 with a F-Class CT;
8. Replace FB Culley 3 with storage and solar; and
9. Replace FB Culley 3 with storage and wind.

2.6 PORTFOLIO PERFORMANCE (SCENARIO BASED RISK ASSESSMENT)

The framework of the Indiana law mandating a triennial IRP[20] also requires the creation of alternative future scenarios with unique sets of inputs. Each candidate portfolio must be modeled in a dispatch run using these scenario-based inputs, which can provide a complementary view of portfolio strengths and weaknesses, separate from the probabilistic analysis that serves as the basis for scorecard measures. Four alternative scenarios were created (High Regulatory, Market Driven Innovation, Decarbonization/Electrification, and Continued High Inflation & Supply Chain Issues), each with a unique set of inputs. All 10 candidate portfolios were modeled in a separate dispatch run for each of the four alternative scenarios.

[20] Indiana Code § 8-1-8.5

EnCompass was run in a market simulation mode holding each of the CEI South portfolios constant but allowing the input assumptions to vary in each of the 200 draws. The results of the scenario-based risk analysis are summarized in Section 8.2.1.

2.7 PORTFOLIO PERFORMANCE (PROBABILISTIC AND STOCHASTIC MODELING RISK ASSESSMENT)

Probabilistic modeling incorporates several market variables and probability distributions into the analysis, allowing for the evaluation of a portfolio's performance over a wide range of market conditions. Quantitative data is extracted from the results and is the foundation for the balanced scorecard and key drivers portion of the risk analysis. Probabilistic modeling begins with the development of 200 sets of future pathways for monthly coal prices, natural gas prices, carbon prices, peak load, and capital expenditures for renewable resources. The 200 sets of inputs were created by developing probability distributions around each uncertainty variable, then stochastically sampling the inputs together to arrive at 200 sets of inputs. These 200 sets of stochastic inputs are then run through the dispatch model, one set at a time for the selected portfolios. 200 instances of key metrics from the dispatch modeling are then used to form distributions around the key output metrics. Thus, the stochastically developed inputs allow for the testing of each portfolio's performance across a wide range probable market conditions.

Once again, all 10 portfolios were subjected to each of the 200 iterations (scenarios) using EnCompass in dispatch mode where the CEI South portfolio is fixed.

2.8 SENSITIVITY ANALYSIS

CEI South conducted several sensitivities in order to put brackets around resulting portfolios when one or more variables were adjusted.

- CEI South performed a sensitivity to test the impact on portfolio NPVs under a sensitivity where CEI South would not be able to monetize 100% of the ITC for new storage projects. In the sensitivity, it was assumed that only 85% of the ITC was received by CEI South. This decrease in ITC monetization results in slightly higher portfolio NPVs. For every 100MW of storage included in a portfolio the NPV would increase by approximately .1% with this reduced ITC monetization percentage.

- The reference case portfolio was run by CEI South with no constraints on the model which resulted in a conversion of two combustion turbines to a combined cycle in 2027 along with 400 MW of wind in 2033 and 10 MW of storage in 2030 and 2042 to meet load requirements during the study period. F.B. Culley 3 remained on-line through 2029.
- CEI South performed a sensitivity to test the impact of increases in wind cost on portfolio NPV and resource decisions. Based on this analysis, if wind costs were to increase, alternate resources, such as solar or storage resources would be selected in order to meet planning reserves with little to no NPV impact on the portfolio.
- CEI South evaluated the cost risk of potential changes in New Source Performance Standard 111B. All 10 portfolios were run through 200 different simulations during the risk analysis, of which 80 included a carbon tax. This potential change in legislation helps to quantify the potential magnitude of the impact different portfolios would be exposed to under future changes to emissions regulation. From the analysis, each of the 10 portfolios saw a 16% - 26% increase in NPV with the inclusion of additional emissions regulation. Portfolios that included converting F.B. Culley 3 to natural gas or had additional renewables and storage experienced less cost risk associated with future emissions regulation changes than the portfolio that included the continued operation of F.B. Culley 3 on coal.
- A sensitivity was run on the impact of a lower capacity accreditation for battery storage over the study period. The base battery storage accreditation included in the modeling was 95% throughout the study period. It is expected that with MISO's shift to a seasonal construct and reviewing of renewable and storage accreditation methodology, there is potential that battery accreditation will decrease in the future. For modeling of this sensitivity, a declining capacity accreditation was applied. The updated capacity accreditation starts at 100% in 2023 and decreases from 2028

until 2037 to 75% where it remains for the rest of the study period. These annual battery storage capacity accreditation values were utilized by MISO in their MISO Futures Report LRTP Tranche 2 Refresh[21]. When the capacity accreditation is updated from 95% to the declining curve, portfolios which include storage are more reliant on market capacity purchases or would need to procure additional resources to meet CEI South's capacity needs. The reduction of capacity accreditation in the out years from 95% to 75% results in increased portfolio costs of up to 2.9%. Future seasonal capacity accreditations for 4-hour storage are difficult to quantify in MISO, but as more storage is added to the system accreditation is expected to decline. In some regions of the US, storage capacity accreditation is projected to decline even further than the 75% accreditation used in this sensitivity.

- CEI South evaluated the impacts of a large industrial load on their system. A 300 MW increase to the current load forecast was included in the modeling. From an unconstrained run this led the model to select the conversion of AB Brown 5 and 6 CTs to a CCGT and additionally selected a J-class CT in order to meet the energy and capacity needs of new and existing customers.

2.9 BALANCED SCORECARD

The Risk Analysis (based on the probabilistic modeling) of each of the portfolios was developed by 1898 & Co. using the EnCompass dispatch model. There were several steps to this process:

- The first step was to develop the input distributions for each of the major market and regulatory drivers, including average and peak load growth and shape, natural gas prices, coal prices, carbon prices and technology capital costs.

[21]MISO LRTP Tranche 2 – Future Refresh Assumptions Book; April 27, 2023 https://cdn.misoenergy.org/20230308%20PAC%20Item%2008a%20Futures%20Refresh%20Assumptions%20Book628109.pdf

- The second step was to run a probabilistic model (Monte Carlo) which selected 200 possible future states over the 20-year study planning period. This also formed the basis for the scenario input development.
- Each candidate portfolio was then run through simulated dispatch for the 200 possible future states using the EnCompass production cost model. EnCompass dispatches the candidate portfolio for each sampled hour over the planning horizon. For this risk analysis procedure, EnCompass assumes that each CEI South candidate portfolio is constant[22] but the input assumptions vary in each of the 200 draws. CEI South generation, costs, emissions, revenues, etc. are tracked for each iteration over time.
- Next, values for each metric are tracked across all 200 iterations.
- The averages of these measures are used as the basis for evaluation in the balanced scorecard.

The results of risk analysis can be found in Section 8 Portfolio Development and Evaluation.

2.10 SELECTION OF THE PREFERRED PORTFOLIO

The risk analysis includes scenario modeling, probabilistic modeling, sensitivity and other analyses to inform judgment in the selection of the preferred portfolio. In addition, a key part of selecting the preferred portfolio was based on how well each portfolio met multiple objectives as outlined in Section 2.3, under 200 iterations representing different, but internally consistent and plausible market condition scenarios. The selection process consisted of several comparisons illustrating each candidate portfolio's performance measured against competing objectives. The goal is to create the right balance between satisfying the competing objectives. The preferred portfolio delivered the best balance of performance across all competing metrics when viewed across the full range of 200 iterations, while also maintaining reliability and providing resource diversity, system

[22] Capacity purchases are allowed to change between the 200 draws to meet planning reserve margin requirements

flexibility, resilience and stability. To help illustrate tradeoffs, CEI South used a Balanced Scorecard, as shown below in Figure 2.7 and further discussed in Section 8.

Figure 2.7 – Balanced Scorecard Illustration

Balanced Scorecard	Objective	Affordability / Cost Risk				Environmental Sustainability		Reliability				Market Risk Minimization							
Portfolio	Metric	20 Year NPVRR ($M)	Delta From Reference (%)	Proportion of Energy Generated by Resources With Exposure to Coal and Gas Markets and Market Purchases (%)	95% Value of NPVRR ($)	CO2 Intensity (Tons CO_2/kwh)	CO2 Equivalent Emissions (Stack Emissions) (Tons CO_2)	Must Meet MISO Planning Reserve Margin Requirement in All Seasons (MW)		Fast Start Capability (MW)	Spinning Reserve (MW)	Energy Market Purchases			Energy Market Sales			Capacity Market Purchases or Sales (%)	
								Summer	Winter			Average	Near Term Max	Long Term Max	Average	Near Term Max	Long Term Max	Purchases	Sales
Reference Case																			
Business as Usual																			
Convert F.B. Culley 3 to Natural Gas by 2027																			
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar																			
Convert F.B. Culley 3 to Natural Gas by 2030																			
Diversified Renewables																			
Diversified Renewables (Early Storage & DG Solar)																			
F-Class CT																			
Replace FB Culley 3 with Storage and Solar																			
Replace FB Culley 3 with Storage and Wind																			

The preferred portfolio represents CEI South's assessment, based on the analysis, of an appropriate balance between all identified objectives (See Figure 2.2) under a wide range of future conditions.

SECTION 3
PUBLIC PARTICIPATION PROCESS

3.1 PUBLIC PARTICIPATION PROCESS

CEI South continues to incorporate continuous improvement opportunities into the stakeholder process based on comments in the Director's report and stakeholder feedback. Most importantly, CEI South implemented tech-to-tech calls and file sharing throughout the process to allow for more meaningful information sharing and dialogue. As a result, significant stakeholder input was directly included in key areas of the IRP, including but not limited to portfolio development, scenario development, scorecard development (metrics and measures), and modeling inputs such as energy efficiency inputs. While improvements have been made, CEI South's objectives for stakeholder engagement remain the same:

- **Listen**: Understand concerns and objectives
- **Inform**: Increase stakeholder understanding of the Integrated Resource Plan process, key assumptions and the challenges facing CEI South and the electric utility industry
- **Consider**: Provide multiple forums for relevant, timely stakeholder feedback at key points in the Integrated Resource Plan process to inform CEI South's decision making

IRP stakeholders include, but are not limited to, CEI South residential, commercial and industrial customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers and advocacy groups, shareholders, economic development groups, generation developers, and elected officials.

In the first public stakeholder meeting, CEI South publicly made 12 commitments and followed through with all throughout the process (significant improvements per stakeholder request noted in italics):

1. To strive to make every encounter meaningful for stakeholders and for us
2. That the IRP process informs the selection of the preferred portfolio

3. To utilize an All-Source RFP to gather market pricing & availability data (*incorporated stakeholder feedback prior to publishing)*
4. *Per stakeholder request*, to utilize EnCompass software to improve visibility of model inputs and outputs
5. *Per stakeholder request*, to conduct technical meetings (tech-to-tech) with interested stakeholders who sign an NDA
6. To include a balanced risk score card. Draft to be shared at the first public stakeholder meeting
7. To work with stakeholders on portfolio development
8. To test a wide range of portfolios in scenario modeling and ultimately in the risk analysis
9. To conduct a sensitivity analysis
10. To evaluate options for existing resources
11. That the IRP will include information presented for multiple audiences (technical and non-technical)
12. *Per stakeholder request*, to 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[23]
    - Full set of final modeling results – March 7th to March 31st [24]

The first three stakeholder meetings began with stakeholder feedback. CEI South would review all requests since the last stakeholder meeting and provide feedback. Often suggestions were incorporated, but in instances where suggestions were not, CEI South made a point to discuss further and explain why not. Notes for each meeting were included in question and answer format, summarizing the conversations. Additionally,

[23] Provided final draft modeling files on December 20, 2022, for stakeholders that signed an NDA as part of the tech-to-tech group
[24] Updated deterministic modeling results were provided to stakeholders on March 7, 2023, and provided stochastic modeling results April 27, 2023, following the final public stakeholder meeting.

feedback was received, and questions were answered via e-mail (irp@centerpointenergy.com) and tech-to-tech meetings in between each session per stakeholder request. The final meeting was a preview of the preferred portfolio and a discussion of the analysis. CEI South felt it was important to hold all stakeholder meetings in person in Evansville, IN (including an option to attend virtually). Tech-to-tech meetings were held virtually.

Stakeholder Meeting dates and topics covered are listed below:

Figure 3.1 – 2022/2023 Stakeholder Meetings

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

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

Per stakeholder request, CEI South included tech-to-tech meetings with stakeholders who signed an NDA. The purpose of the meetings was to discuss confidential information between public stakeholder meetings. The invitation was open to those that did not have a competitive interest in the information being shared. The OUCC, CAC, Sierra Club, and IURC staff regularly attended these meetings. Most often, the topic of conversation was draft modeling inputs/outputs. Stakeholder tech-to-tech Meeting dates and topics covered are listed below:

Figure 3.2 – 2022/2023 Tech-to-Tech Meetings

October 31, 2022	November 7, 2022	December 7, 2022	Feburary 28, 2023
• Modeling timeline • Modeling updates • Modeling setup • Accreditation of resources • Preliminary Reference Case model selections	• Reviewed 25 CAC questions on EnCompass modeling input file	• Review of modeling ouputs (confidential slides) ahead of CEI South stakeholder meeting	• Discussed risk analysis portfolios • Discussed updated reference case modeling results for each portfolio • Discussed scenario modeling results for each portfolio • Reviewed draft scorecard • Stochastic modeling approach

Beyond tech-to-tech meetings and public stakeholder meetings, CEI South met with individual stakeholders on various topics. For example, CEI South met several times with the CAC on Energy Efficiency modeling inputs.

3.2 KEY ISSUES DISCUSSED AND STAKEHOLDER INPUT

Throughout the process CEI South engaged stakeholders on key inputs into the IRP, which helped shape the outcome of the analysis. This section of the IRP highlights some of the key issues discussed and stakeholder input. For a more complete summary of stakeholder feedback addressed in each stakeholder meeting, please see section 3.1 in the technical appendix.

3.2.1 All-Source RFP

The 2022/2023 IRP kicked off with an All-Source Request for Proposal that was issued on May 11, 2022, where CEI South solicited input and incorporated feedback from stakeholders prior to posting. Stakeholders requested several updates to the All-Source RFP prior to it being issued. CEI South made updates accordingly in the following areas:

- CEI South added specific language to allow for proposals to consider re-use of injection rights;
- CEI South invited proposals of all size and removed the prohibition of behind-the-meter generation;
- CEI South added language to clarify how bidders should submit bid pricing;
- CEI South allowed storage proposals of any size and duration;
- CEI South included suggestions on scoring criteria regarding historical performance; and
- CEI South also clarified some language and made some corrections to the document.

After receiving initial bids, the Inflation Reduction Act (IRA) was passed. Stakeholders requested bidders be allowed to update their proposals to reflect the passage of the IRA. Bidders were provided an opportunity to update their proposals to reflect the most current information available. New information was incorporated into the modeling, and updated bid information was provided to stakeholders, without a competitive interest, who signed an NDA.

3.2.2 Resources

Throughout the process stakeholders made specific requests around resources that were modeled. Below are some major adjustments within IRP modeling. For a larger list of updates, please see the technical assessment, section 3.1.

3.2.2.1 Battery Storage

Battery Storage resources were discussed throughout the process. CEI South initially planned to model a long duration storage resource utilizing compressed air storage as a proxy for a breakthrough technology. This resource, while not likely available to CEI South, is an established technology providing similar benefits to the system. Real costs were utilized to provide this estimate.

IRP stakeholders did not agree compressed air storage was a good proxy for long duration storage and suggested CEI South either include longer duration lithium ion or utilize an upcoming technology like, iron air battery. While iron air batteries could help solve the long duration storage need, the technology is not yet in commercial operation, and CEI South did not have good cost data to model in this IRP. CEI South will continue to watch updates from Form Energy, the industry leader of this upcoming technology, and may incorporate this resource in future IRPs. Ultimately, CEI South did allow the model to select multiple four-hour blocks of lithium ion storage or an alternative 10-hour storage resource. The long-duration storage proxy was pushed out to 2032, so it could not be selected in the near term. While available for selection, it was not selected as a resource within optimizations.

Stakeholders also had suggestions about how batteries should be modeled, and the following updates were made:

- Utilized bid information to update low- and high-cost paths. CEI South acted on this suggestion and started price paths at lower and higher points, based on the highest and lowest bids included within the pricing average. This allowed for price variation in the early years of deterministic modeling.

- Updated model to reflect impact of the ITC to be reflected in year one. Ultimately this adjustment was more in line with the intent of the IRA and lowered the upfront cost for this resource.

3.2.2.2 DSM

Demand Side Management (DSM) resources were consistently discussed throughout the IRP process with stakeholders in public meetings, DSM oversight meetings (OUCC and CAC), and in one-off meetings with external stakeholder consultants to better understand inputs and results. CEI South discussed both demand response and energy efficiency.

Beginning with demand response, stakeholders requested CEI South model more industrial demand response. CEI South has no more industrial demand response registered with MISO; as MISO rules have evolved, there are no customers still interested in the program. However, recognizing CEI South will be in for a rate case at the end of 2023 with an opportunity to adjust rates and a stakeholder suggestion that CEI South work with an aggregator to try to untap potential opportunity in this area; CEI South agreed to increase the amount of demand response modeled to 25 MWs in all seasons. The cost of this program was set consistent with a bid received in the All-Source RFP, and CEI South has engaged this aggregator to see if they can help us procure more C&I DR. Conversations are on-going.

Another request of stakeholders was to pursue a residential rate program. As discussed in section 6.3.2.6 Other Innovative Rate Design, CEI South is actively planning to pursue a critical peak pricing pilot. This pilot should help CEI South better evaluate the potential of this Time of Use program and will provide valuable data for future IRPs. CEI South did model an indicative pilot in this IRP.

Multiple other adjustments were made to model energy efficiency programs. CEI South is committed to helping its customers use energy wisely and save money on energy bills; as such, CEI South worked hard to maximize the amount of energy efficiency that could be selected within the model through regrouping various programs to ensure the right level of cost-effective energy efficiency was economically selected. CEI South worked collaboratively with stakeholders to help them understand inputs and worked to make adjustments consistent with stakeholder suggestions. Specific adjustments, consistent with stakeholder input, are included below:

- Captured avoided T&D line losses at marginal level instead of system average;
- Included 25 MWs of Industrial DR as a resource;
- Modeled "enhanced RAP" for commercial EE. This includes all realistic, achievable, potential and some maximum achievable potential;
- Adjusted low-income bundles to include higher short-term inflation rates;
- Plan to evaluate rate programs (critical peak pricing, TOU, etc.) in the future through a pilot; and
- Separated residential bundles into high cost and low to medium cost.

Ultimately this process was used to adjust EE cost to the maximum level, utilizing MPS data. CEI South felt this approach was superior to adjusting costs in scenarios and deviated from the initial approach of adjusting price based on a standard deviation up or down.

3.2.2.3 Hydro Electric

Stakeholders requested CEI South fully consider hydroelectric resources, given our proximity to the river and the benefits this resource provides. CEI South included two hydroelectric sources within optimization modeling, which included the ITC benefit provided in the IRA legislation, recently passed by the Biden administration. One project is located near F.B. Culley Power Plant, and the other is located near A.B. Brown Power plant. Even with the ITC applied, these resources were not selected based on economics. Additionally, CEI South modeled several portfolios that included hydro; however, these portfolios were ultimately screened out due to high cost. While these resources could help further diversify CEI South's fleet, the relatively small size and high cost led to hydro not being included in any portfolios that ultimately were included within the risk analysis.

3.2.3 Commodity Prices

CEI South began the IRP process by gathering commodity price forecasts from multiple sources. The timing of the IRP stakeholder process corresponded to a spike in natural gas prices. As such, stakeholders disagreed with the original consensus forecast, stating the original consensus forecast was too low. CEI South agreed to update the forecast and utilized the most up to date forecasts from each of its vendors, prior to finalizing modeling. Gas prices have been very volatile over the last year, peaking at around $9 per Million Btu (Henry Hub spot prices) in August 2022, the time of our first IRP stakeholder meeting to around $2 in February 2023. The CEI South reference price forecast reflects forecasts are higher than what was originally developed. Updated forecasts reflect the price spike in the summer of 2022.

Another adjustment CEI South made to commodity price forecasts is reflected within scenarios modeling. Originally, in the high regulatory scenario, CEI South reflected a coal price that was the same as the reference case, noting demand would be going down, offsetting a potential increase that may come through higher regulations. Stakeholders pushed back on this narrative. Based on comments provided, CEI South found it plausible that in a high regulatory scenario coal prices could increase as coal mines shut down due to a more oppressive regulatory environment. This could lead to the remaining coal producers charging more, passing costs of new regulations on to remaining customers. CEI south updated the high regulatory scenario coal price to be higher than the reference case.

3.2.4 Score Card

Several significant additions were made to the scorecard per stakeholder request across multiple objectives. First, CEI South added the portion of energy generation with exposure to coal and gas markets gives further insight to risks posed by commodity markets and potential future regulatory requirements. This metric, expressed as a percentage, is the generation from coal and gas divided by the total fleet generation across 200 iterations.

Second, CEI South calculated CO_2 equivalent stack emissions within the Environmental Sustainability objective to account for other emissions that are created by burning coal or natural gas. Third, CEI South added metrics in the Market Risk Minimization objective to provide more information to better understand reliance on energy sales / purchases and annual capacity sales / purchases in the near term and the long term.

3.3 STAKEHOLDER INPUT

During the 2022/2023 IRP, stakeholders provided their input in several ways: 1) verbal feedback through question/answer sessions during public stakeholder meetings; 2) via written feedback/requests; 3) ongoing conversations; and 4) tech-to-tech meetings between stakeholder sessions.

CEI South worked diligently to have an open forum for stakeholders to voice questions/concerns and make suggestions on the IRP analysis. Each CEI South stakeholder meeting was opened by Richard Leger, Senior Vice President Indiana Electric. He and other senior management, CEI South subject matter experts and expert consultants actively participated in each meeting to help address stakeholder questions/concerns.

Below is a summary of key feedback that was ultimately included in the 2022/2023 IRP analysis. For a full list, including suggestions not taken, see the technical appendix Technical Appendix Attachment 3.1 Stakeholder Materials.

Figure 3.3 – Summary of Key Stakeholder Input

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)

Request	Response
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
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 customers as a registered resource in 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

Request	Response
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
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

Request	Response
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

3.4 DATA REQUESTS SUMMARY

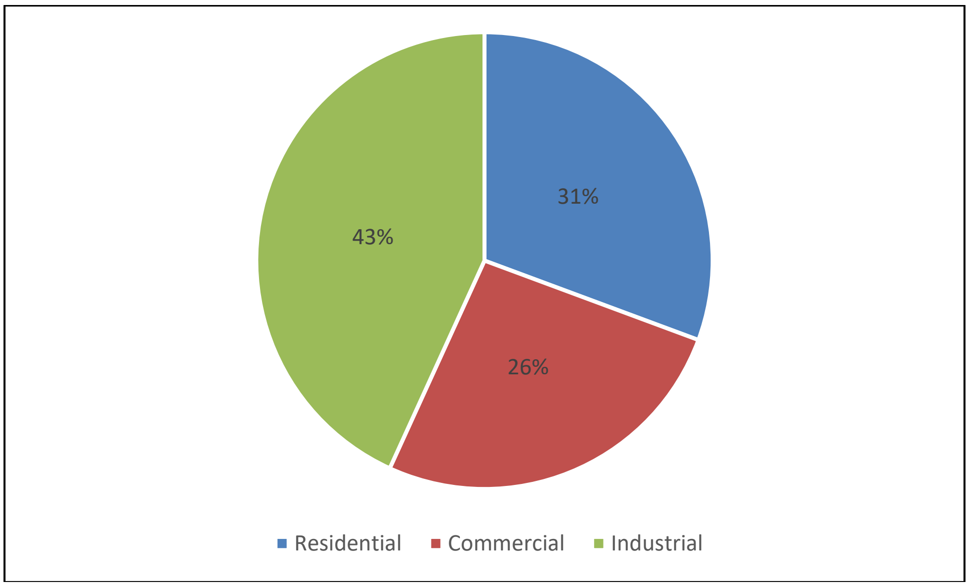
During the public stakeholder process CEI South received seven informal data requests from the CAC and Sierra Club. These data requests and CEI South's response can be found in the technical appendix 3.

SECTION 4
CUSTOMER ENERGY NEEDS

4.1 CUSTOMER TYPES

CEI South serves more than 151,000 electric customers in Southwest Indiana; Evansville is the largest city within the service area. The service area includes a large industrial base with industrial customers accounting for approximately 43% of energy sales in 2022. The residential class accounts for 31% of sales with approximately 132,000 customers and the commercial class 26% of sales; there are approximately 19,000 nonresidential customers. System 2022 energy requirements were 4,571 GWh with non-weather normalized system peak reaching 1,022.2 MW. Figure 4.1 shows 2022 class-level sales distribution.

Figure 4.1 – 2022 CEI South Sales Breakdown



4.2 FORECAST DRIVERS AND DATA SOURCES

The main drivers of the energy and demand forecast include the following: historical energy and demand data, economic and demographic information, weather data, equipment efficiencies and equipment market share data.

Itron used more than 10 years of historical energy and demand data within the energy and demand forecasts. This data is maintained by CEI South in an internal database and was provided to Itron. Energy data is aggregated by rate class for the purposes of forecasting. There are two major rate classes for residential customers: the standard residential rate and the transitional electric heating rate (rate closed to new premises). Information for these rates is combined for the purposes of forecasting residential average use per customer. Similarly, small commercial (general service) rates are combined to produce the commercial forecast and large customer rates are combined to produce the industrial forecast. The demand forecast utilizes total system demand.

Economics and demographics are drivers of electricity consumption. Historically, there has been a positive relationship between economic performance and electricity consumption. As the economy improves, electricity consumption goes up and vice versa. Economic and demographic information was provided by S&P Global (formerly IHS Markit), which contains both historical results and projected data throughout the IRP forecast period. Examples of economic variables used include, but are not limited to, population, income, output and employment.

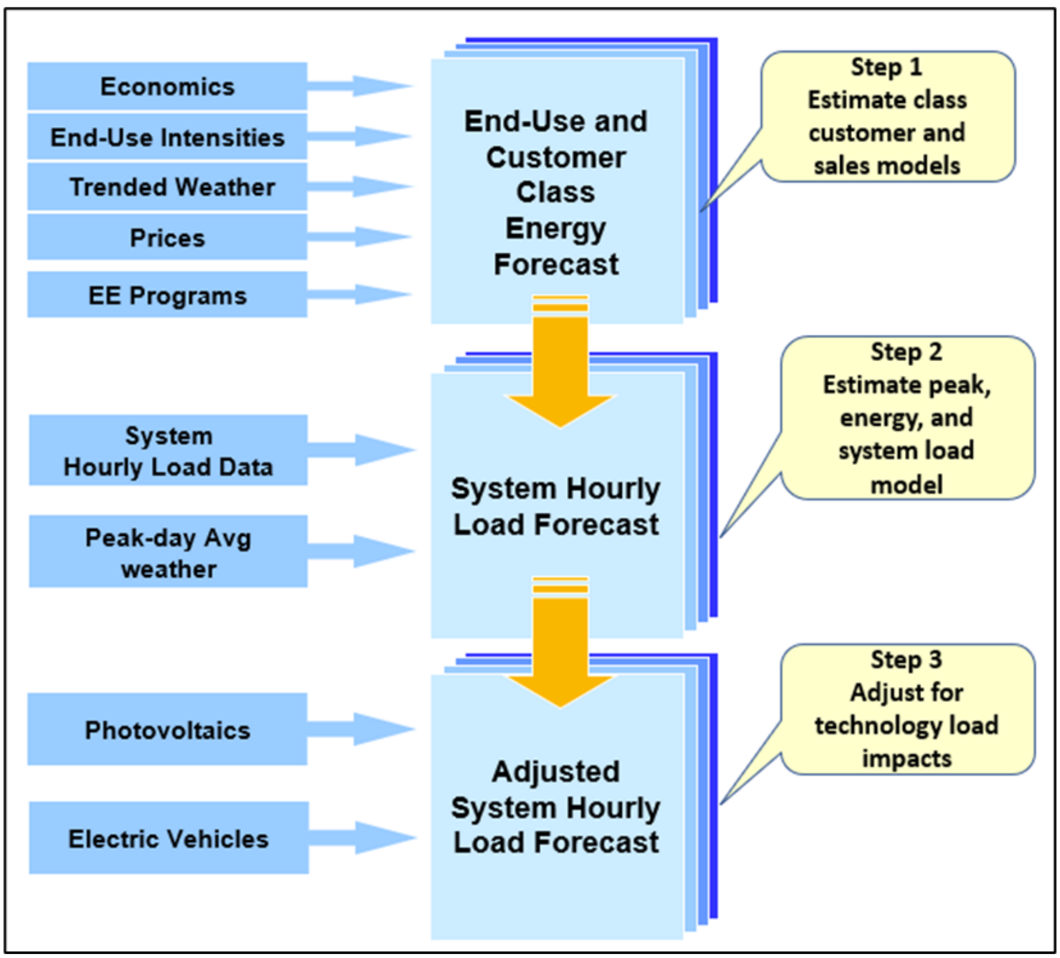
Weather is also a driver of electric consumption. CEI South’s peak demand is typically in summer when temperatures are hottest. Air conditioning drives summer usage. Itron used a trended weather assumption for the normal weather in the sales and demand forecast in order to capture recent weather activity. The trended weather picks up the 0.05 degree annual increase in temperature the Evansville area has experienced since 1988.

Itron, Inc. provides regional Energy Information Administration (“EIA”) historic and projected data for equipment efficiencies and market shares. This data captures projected changes in equipment efficiencies based on known codes and standards and market share projections over the forecast period, including but not limited to the following: electric furnaces, heat pumps, geothermal, central air conditioning, room air conditioning, electric water heaters, refrigeration, dish washers, dryers, etc. Residential market share data was adjusted to CEI South’s service territory based on the latest appliance saturation survey data.

4.3 MODEL FRAMEWORK

The long-term energy and demand forecasts are based on a build-up approach. End-use sales derived from the customer class sales models (residential, commercial, industrial and street lighting) drive system energy and peak demand. Energy requirements are calculated by adjusting sales forecast upwards for line losses. Peak demand is forecasted through a monthly peak-demand linear regression model that relates peak demand to peak-day weather conditions and end-use energy requirements (heating, cooling and other use). System energy and peak are adjusted for residential and commercial PV adoption and EV charging impacts. Figure 4.2 shows the general framework and model inputs.

Figure 4.2 – Class Build-up Model



In the long-term, both economic growth and structural changes drive energy and demand requirements. Structural changes include the impact of changing appliance ownership trends, end-use efficiency changes, increasing housing square footage and thermal shell efficiency improvements. Changing structural components are captured in the residential and commercial sales forecast models through a specification that combines economic drivers with end-use energy intensity trends. This type of model is known as a Statistically Adjusted End-Use ("SAE") model. The SAE model variables explicitly incorporate end-use saturation and efficiency projections, as well as changes in population, economic conditions, price and weather. Both residential and commercial sales are forecasted using an SAE specification. Industrial sales are forecasted using a two-step approach, which includes a generalized econometric model that relates industrial sales to seasonal patterns and industrial economic activity. Streetlight sales are forecasted using a simple trend and seasonal model.

4.4 CUSTOMER OWNED DISTRIBUTED ENERGY RESOURCES

Distributed generation ("DG") is an electrical source interconnected to CEI South's transmission or distribution system at the customer's site. The power capacity is typically small when compared to the energy companies' centralized power plants. DG systems allow customers to produce some or all of the electricity they need. By generating a portion or all of the electricity a customer uses, the customer can effectively reduce their electric load. With respect to CEI South's electric service territory, DG will likely take these forms:

Small – 10 kW and under – roof-top photovoltaic ("PV") systems, small wind turbine, etc. interconnected at distribution secondary voltage (120/240 V, etc.)

Medium – 10 kW to 10 MW – large scale PV systems, wind turbine(s), micro-turbine(s), etc. interconnected at distribution primary voltage (4 kV or 12 kV)

Large – 10 MW and over – heat recovery steam generator, combustion turbine, etc. interconnected at transmission voltage (69 kV and above)

Most renewable DG systems only produce power when their energy source, such as wind or sunlight, is available. Due to the intermittency of the power supply from DG systems, there will be times when the customer needs to receive electricity from CEI South. Conversely, when a DG system produces more power than the customer's load, excess power can be sent back to CEI South's electric system through one of two programs, Net Metering or Excess Distributed Generation ("EDG"). Net metering customers are charged the retail rate for the net power that they consume. EDG customers are credited at the EDG rate for their excess power and charged the retail rate for the inflow power delivered by CEI South.

4.4.1 Current DG

As of December 2022, CEI South had approximately 982 residential solar customers and 139 commercial solar customers, with an approximate installed capacity of 27.8 MW. Based on recent solar installation data, the residential average size is 10.5 KW, while the commercial average system size is 126.2 KW. CEI South has incorporated a forecast of customer-owned photovoltaic systems into the sales and demand forecast.

CEI South monitors Combined Heat and Power ("CHP") developments in its service area and adjusts the load forecast for any known, future customer-owned CHP installations. A large CHP system went into service on CEI South's system in 2017.

4.4.2 Solar DG Forecast

The energy and peak forecasts incorporate the impact of customer-owned photovoltaic systems. System adoption is expected to increase as solar system costs decline in the long run.

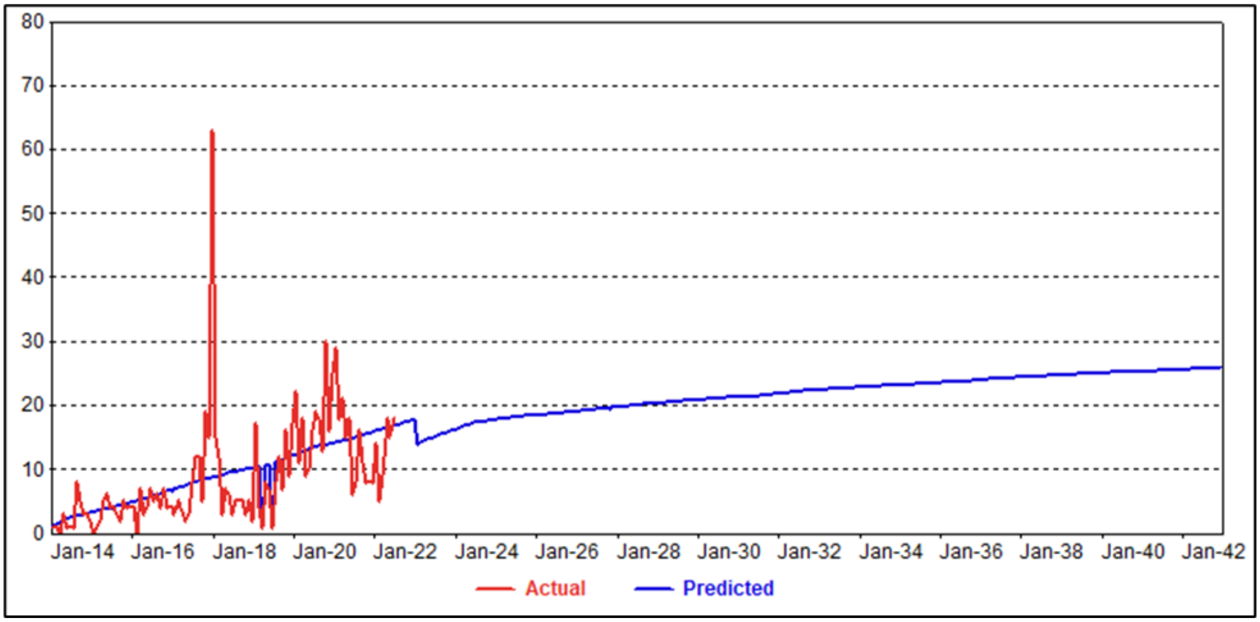
The primary factor driving system adoption is a customer's return-on-investment. Itron created a simple payback model, which was used as proxy. Simple payback reflects the length of time needed to recover the cost of installing a solar system - the shorter the payback, the higher the system adoption rate. From the customer's perspective, this is the number of years until electricity generated from the system is considered "free". Solar investment payback is calculated as a function of system costs, tax credits, and incentive payments, retail electric rates and treatment of excess generation (solar generation returned to the grid). The payback calculation incorporates the impact of switching from net metering to the EDG. Federal investment tax credits are extended in accordance with the Inflation Reduction Act.

One of the most significant factors driving adoption is declining system costs: costs have continued declining over the last five years[25]. In 2010, residential solar system cost was approximately $8.00 per watt. By 2020 costs had dropped to $3.80 per watt. For the forecast period, system costs are expected to continue to decline 10% annually through 2024 and an additional 3% annually after 2024.

The solar adoption model relates monthly residential solar adoptions to simple payback. Figure 4.3 shows the resulting residential solar adoption forecast.

[25] Lawrence Berkeley National Laboratory, Tracking the Sun report, pages 26 and 33 https://emp.lbl.gov/sites/default/files/2_tracking_the_sun_2022_report.pdf

Figure 4.3 – Residential Solar Share Forecast



In the commercial sector, there have been too few adoptions to estimate a robust model; commercial system adoption has been low across the country. Some challenges to commercial adoption are higher investment hurdle rates, building ownership issues (i.e., the entity that owns the building often does not pay the electric bill) and physical constraints as to the placement of the system. For this forecast, Itron assumed there continues to be some commercial rooftop adoption by allowing commercial adoption to increase over time, based on the current relationship between commercial and residential adoptions rates.

As shown in Figure 4.4, incremental installed capacity of solar is expected to increase by 130.9 MWs by 2042.

Figure 4.4 – New Solar Capacity and Generation

Year	Total Generation MWh	Installed Capacity MW (Aug)	Demand Impact MW
2022	1,537	1.8	0.7
2023	8,211	6.5	2.3
2024	15,018	11.4	4.1
2025	22,399	16.8	6.0
2026	30,039	22.3	8.0
2027	37,960	27.9	10.0
2028	46,299	33.9	12.1
2029	54,615	40.0	14.4
2030	63,335	46.2	16.6
2031	72,103	52.5	18.9
2032	81,374	59.1	21.3
2033	90,470	65.7	23.4
2034	100,029	72.6	17.9
2035	109,595	79.4	19.6
2036	119,645	86.5	21.2
2037	129,363	93.6	23.1
2038	139,416	100.9	24.7
2039	149,790	108.3	26.3
2040	160,542	115.8	28.6
2041	170,589	123.2	30.2
2042	181,272	130.9	32.2

4.4.3 Potential Effects of Distributed Generation on T&D

Distributed Generation customers currently affect a small amount of load on each respective distribution circuit, which has not caused significant operational issues for CEI South. At higher levels of DG penetration, CEI South would encounter more operational issues and would need to allocate more resources to mitigate these issues. Some examples of potential issues would include:

- **High voltage mitigation** – With a high penetration of DG, distribution feeder voltage profiles could become unacceptably high when light loading periods coincide with high DG output.
- **Protection system modifications** – Traditionally, electric distribution feeders have been designed as unidirectional from the energy company to the customer.

Voltage regulation and feeder protection strategies are designed based on this premise. With high DG penetration under light load with high DG output, power flow could reverse from the customer to the energy company.

- **Power quality and harmonics mitigation** – Power quality issues are one of the major impacts of high photovoltaics penetration levels on distribution networks. Power inverters used to interface PV arrays to power grids increase the total harmonic distortion of both voltage and current, which can introduce heating issues in equipment like transformers, conductors, motors, etc.
- **Short-term load forecast uncertainty** – At higher levels of DG penetration, short-term load forecasting becomes more difficult. DG resources work to offset the customer's load, but their output can be variable depending upon weather conditions. A load forecasting technique would need to be implemented that is more granular and more responsive to short-term weather conditions.
- **Capacitor banks on the distribution feeders** – Capacitor banks are used to improve power factor and maintain acceptable voltages along the lines. These are strategically placed based on load/distance from the normal source (substation). Once additional sources (DG) are added to the circuits, capacitor bank placement will need to be reevaluated.
- **Electric Rates** – CEI South's electric rates are designed to recover the fixed costs of providing service (transmission, distribution, metering, etc.) via energy and (for large customers) demand charges, along with an associated fixed monthly customer facilities charge. The fixed monthly charge does not reflect the full amount of fixed costs that CEI South incurs to provide retail electric service. Net Metering customers (who generate a portion of their own electricity but still rely on the electric grid) may avoid paying towards the recovery of the fixed costs of the grid that are recovered through the energy charge, which leads to CEI South's under recovery of the cost of providing service. Over time, as base rates are updated periodically, recovery of these costs shifts to non-net metering customers, resulting in a subsidy to net metering customers. Net metering is only available to

premises that installed an eligible generation system prior to implementation of Rider EDG.

- **Transmission Power Flows –** High DG penetration impact power flow on transmission lines. Depending on the concentration and location of these resources, the transmission system may need to be reconfigured, with consideration given to the dependency of the resources on the weather (wind, solar, etc.). High DG penetration may also impact flows on transmission system tie lines to other entities and require additional mitigations, such as installation of reactors or phase shifters to control flows.
- **Generation Reserves** – With the output of DG being weather dependent, the remaining fleet of generators and the electric system must be capable of quickly reacting to the fast and potentially large generation changes on the system, as well as providing generation support during times when DG will not be available (such as nighttime for solar DG). The adoption of Electric Vehicles could also lead to increased load demand in the nighttime hours as they are charging. These issues will need to be evaluated and potentially require mitigations such as storage facilities, quick start generators, etc.
- **Additional Operational Challenges** – High DG penetration causes additional challenges to operate the electric system in a safe and reliable manner due to loss of inertia on the power system by replacing traditional rotating machine generators (high inertia) with inverter-based generators (no/low inertia). These challenges include maintaining spinning and quick start reserves, power system frequency fluctuations and increased system operations (tripping), among others. Each of these issues would need to be evaluated and potentially mitigated to maintain reliable and safe power system operation.

4.5 ELECTRIC VEHICLES

4.5.1 Current EVs

In 2019, CEI South estimated 238 registered electric vehicles were in the counties that CEI South serves: this included full electric (i.e., Battery Electric Vehicles - BEV) as well as plug-in hybrid electric ("PHEV") vehicles. The 238 vehicles were comprised of 105 BEVs and 133 PHEVs, with a total of 23 different make/model vehicles represented. This estimate was based on Indiana BMV registration data for the counties that CEI South serves. CEI South purchases quarterly from the BMV a list of vehicle registrations for the counties that CEI South serves.

4.5.2 EV Forecast

As electric vehicles are gaining more traction in the vehicle market, CEI South decided to include an electric vehicle forecast in the 2022/2023 IRP. As described in the 2022 Long-Term Electric Energy and Demand Forecast Report in the Technical Appendix 4.1 of this IRP, Itron created an electric vehicle forecast utilizing a consensus forecast, averaging the EIA Annual Energy Outlook and BloombergNEF forecasts to calculate the share of registered light-duty vehicles which are electric. Itron used the EIA's assumption of total light-duty vehicles per household. Using this data, the average number of cars per household and projected electric vehicle shares were calculated. This number is multiplied by the forecast of residential customers to create a projected number of vehicles per CEI South household. Itron then applied the consensus projected saturation of battery electric vehicles and plug in hybrid electric vehicles.

Electric vehicles' impact on CEI South's load forecast depends on the amount of energy a vehicle consumes annually and the timing of vehicle charging. Battery electric vehicles ("BEV") consume more electricity than plug-in hybrid electric vehicles ("PHEV") and accounting for this distinction is important. An EV weighted annual kWh use is calculated based on the current mix of EV models. EV usage is derived from manufacturers' reported fuel efficiency to the federal government (www.fueleconomy.gov). The average annual kWh for the current mix of EVs registered in CEI South's service territory is 3,752kWh for BEV and 2,180 kWh for PHEV based on annual mileage of 12,000 miles.

Electric vehicles' impact on peak demand depends on when and where EVs are charged. Since CEI South does not have incentivized BEV/PHEV off-peak charging rates, it is assumed that most of the charging will occur at home in the evening hours. Figure 4.5 shows the electric vehicle forecast.

Figure 4.5 – Electric Vehicle Load Forecast

Year	Total Vehicle (MWh)	Summer Peak Impact (MW)	Winter Peak Impact (MW)
2024	691	0.0	0.0
2025	1,808	0.1	0.3
2026	3,500	0.2	0.5
2027	6,069	0.3	0.8
2028	9,972	0.5	1.4
2029	15,909	0.7	2.2
2030	21,251	1.0	3.7
2031	28,809	1.3	5.1
2032	39,752	1.8	7.0
2033	55,841	2.5	9.8
2034	79,773	3.6	13.9
2035	93,941	4.3	16.5
2036	109,076	7.6	19.1
2037	124,785	8.7	25.5
2038	140,262	9.7	28.5
2039	155,391	10.8	31.7
2040	170,208	11.8	34.7
2041	184,488	12.8	37.6
2042	199,831	13.9	40.7
2043	216,348	15.0	44.1
2044	234,119	16.3	47.7

4.5.3 Potential Effects of EVs on Generation, Transmission and Distribution

Electric Vehicles and their associated charging stations currently have a minimal impact on the CEI South electric system and therefore have not caused significant operational issues. As the level of EV charging stations increases, CEI South may encounter multiple operational issues that will need to be evaluated and potentially mitigated. Some examples of potential issues include:

- **Shifting Peak Load** – Increased use of EV will have an impact on the magnitude of daily load demand, as well as the timing of peak loading. If a large concentration of EV charging occurs in the late afternoon and early evening, the daily system peak could be shifted to later in the afternoon or a second (and most likely lesser) peak could occur in the evening.
- **Generation Reserves** – If EV charging largely occurs in the evening or overnight, the electric system would see higher than typical load demand values at times when DG and other solar generation installations would not be available. This would lead to a need for generation support during these hours, such as energy storage facilities, quick start generators, etc.
- **Peak Charging** – If a large portion of EV charging were to occur during peak loading times, the impact of the increased demand could lead to overloaded electrical infrastructure, unless some form of delayed or managed charging is available. These overloaded facilities would need to be upgraded or other system level upgrades would be needed to mitigate the overload conditions.
- **Transmission Planning Concerns** – MISO performs economic studies annually using a range of potential futures. The futures that they are currently evaluating include potential increases in electrification (including EV) at various growth levels. Due to the uncertainty around EV adoption and the differing values being analyzed, uncertainties as to when to complete transmission system upgrades to support a higher level of system peak load due to EV adoption may be introduced. A need for additional planning models and sensitivity analysis would be required to evaluate these uncertainties and determine the appropriate time to perform the needed transmission system upgrades.

- **Dynamic Behavior** – The dynamic behavior of these loads while in a charging state during fault conditions and during re-energization post fault condition is an additional issue that will need to be evaluated. Research is still needed to properly reflect how these types of loads respond from a dynamic behavior perspective and may require additional dynamic modeling for planning studies.

If there is a substantial increase in EV adoption within the next 10 years, it is anticipated there would be a significant change in the system load profile. As an example, the system peak load hour could shift to later in the day. The load profile and generation expansion implications of the changing load shape suggest EV adoption and resulting vehicle charging patterns should be monitored in the upcoming years.

4.6 ENERGY AND DEMAND FORECAST (REFERENCE CASE)

For the IRP filing, the long-term energy and demand forecast does not include energy savings from future DSM programs; DSM activity is considered a supply option and not a reduction to demand. Excluding DSM, total energy requirements and peak demand are expected to average 0.7% annual growth over the next 20 years. The table below shows CEI South's energy and demand forecast; the forecast includes the impact of customer owned distributed generation, electric vehicles, trended weather (warmer summers and winters), company owned distributed generation (solar and landfill gas) and customer EE outside of energy company sponsored programs but excludes future energy company sponsored DSM program savings. For more information on CEI South long-term energy and demand forecasts, including load shapes, see Technical Appendix Attachment 4.1 2022 CEI South Long-Term Electric Energy and Demand Forecast Report.

Figure 4.6 – Energy and Demand Forecast[26]

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2022	4,815,801		1,019		802	
2023	4,725,478	-1.9%	1,010	-0.9%	738	-8.0%
2024	5,163,907	9.3%	1,087	7.6%	812	10.0%
2025	5,152,172	-0.2%	1,087	0.0%	810	-0.2%
2026	5,153,363	0.0%	1,088	0.1%	811	0.1%
2027	5,164,632	0.2%	1,092	0.3%	813	0.3%
2028	5,178,436	0.3%	1,095	0.3%	816	0.4%
2029	5,175,063	-0.1%	1,095	0.0%	816	0.0%
2030	5,178,761	0.1%	1,096	0.1%	817	0.2%
2031	5,199,311	0.4%	1,100	0.3%	821	0.5%
2032	5,238,099	0.7%	1,105	0.5%	828	0.9%
2033	5,254,460	0.3%	1,110	0.4%	831	0.4%
2034	5,277,650	0.4%	1,114	0.4%	836	0.5%
2035	5,304,282	0.5%	1,120	0.6%	841	0.6%
2036	5,345,573	0.8%	1,128	0.7%	849	1.0%
2037	5,377,724	0.6%	1,136	0.7%	855	0.7%
2038	5,418,448	0.8%	1,145	0.8%	862	0.9%
2039	5,455,497	0.7%	1,154	0.8%	869	0.8%
2040	5,493,803	0.7%	1,162	0.7%	875	0.8%
2041	5,518,739	0.5%	1,169	0.6%	880	0.5%
2042	5,551,532	0.6%	1,177	0.6%	886	0.7%
CAGR 22-42		0.7%		0.7%		0.5%

4.7 DISCUSSION OF BASE LOAD, INTERMEDIATE LOAD and PEAK LOAD

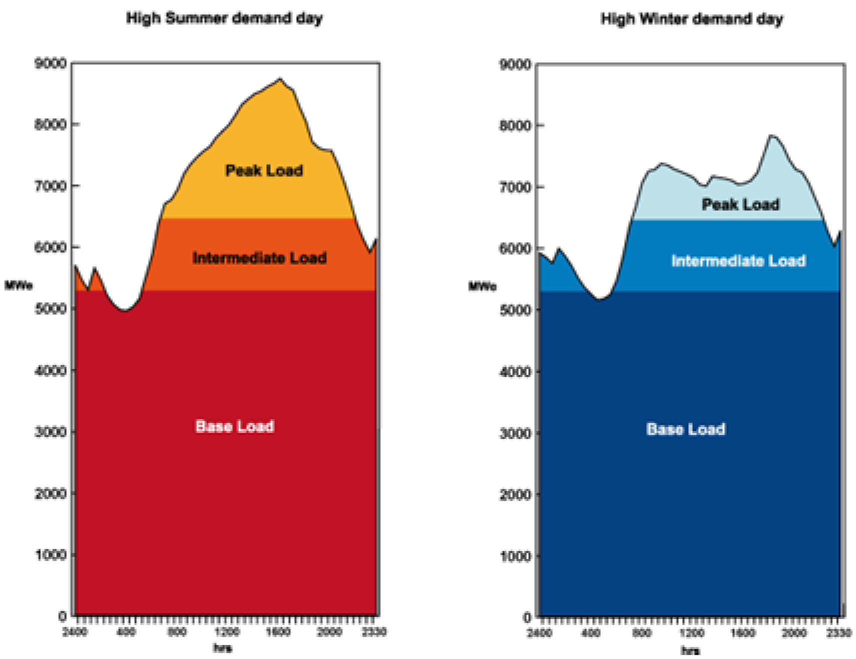
There are three levels of electric load: base load, intermediate load and peak load. Base load is the minimum level of demand on an electrical supply system over 24 hours. Base load is primarily served by power plants which can generate consistent and dependable power. Intermediate load is a medium level of demand. Plants can operate between extremes and generally have output increased in the morning and decreased in the

[26] 2022/2023 IRP energy and demand forecast will differ from what is provided to MISO to match MISO's requirements, particularly the treatment of EE, which is netted out of load

evening. Peak load is the highest level of demand within a 24-hour period. The annual peak hour is typically between June and September, when weather is hottest. For modeling purposes, CEI South uses August as the peak summer month and January as the peak winter month. Typically, peak demand is served by units that can be switched on quickly when additional power is needed.

The graphic below shows an illustrative example of summer and winter peak load.

Figure 4.7 – Typical Load Curve Illustrations (Summer and Winter)



This dynamic is evolving as more intermittent renewable resources, particularly solar, come online. MISO nets out energy produced from renewable resources from customer load. This is expected to shift the net peak into the evening hours where dispatchable resources will be needed to serve customer load.

4.8 STAKEHOLDER INPUT – Load Forecast

CEI South discussed the load forecast data and process initially with stakeholders in the August 18, 2022, stakeholder meeting, providing an opportunity to provide input, question and comment on the draft load forecast before finalizing. On October 11, 2022, in the second public stakeholder meeting, CEI South followed up with the reference case load forecast, providing details on inputs (forecast drivers) for residential as well as commercial and industrial sales. Itron provided details about the structure of the models used and outputs for customer owned distributed generation and electric vehicles and answered stakeholder questions. Additionally, the peak load forecast was provided, along with relevant details.

SECTION 5
The MISO Market

5.1 MISO

Midcontinent Independent System Operator ("MISO") is the independent, not-for-profit Regional Transmission Operator ("RTO") of which CEI South is a member. MISO oversees power delivery across 15 states and the Canadian province of Manitoba and is one of the largest energy and operating reserves market in the world. 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 regarding energy and capacity and can rely on neighboring Zones to an extent, largely depending on transmission infrastructure. Based on MISO's Local Clearing Requirement ("LCR"), which varies by season, approximately 60-80% of CEI South's generation must be physically located within MISO Zone 6.

Figure 5-1 – MISO Local Resource Zones

MISO's two main roles are transmission planning and oversight of its energy, capacity and ancillary service markets. MISO has operational authority to control transmission facilities and coordinate security for its region to ensure reliability. MISO is responsible for dispatch of lowest cost generation units, ensuring the most cost-effective generation meets load needs.

5.2 MISO Planning Reserve Margin Requirement ("PRMR")

MISO requires CEI South and its other member electric utilities to maintain a seasonal PRMR. The PRMR is the amount of resources MISO requires in order to meet a NERC standard of one loss of load event in 10 years and is designed to ensure there is enough power capacity throughout the MISO region to meet customer demands during seasonal peak periods, including peak periods where some equipment might fail. To further ensure the NERC standard of one loss of load event in 10 years, the PRMR is further detailed by the LCR which mandates how much of a LRZ PRMR must be met by generation resources physically located within that LRZ for each respective season. In recent years the amount of available resources to meet load needs throughout MISO has tightened excess capacity that acts as a reliability safeguard. This trend is continuing as more baseload units are projected to retire in the coming years. As a result, long term dependence on the market for capacity and energy has considerable risk.

The illustration in Figure 5.2 below shows the load on a typical day and load on the peak day with the reserve margin requirement. Figure 5.3 shows historical PRMR by year since 2015.

Figure 5-2 – Illustration of Load Curve and Planning Reserve Margin

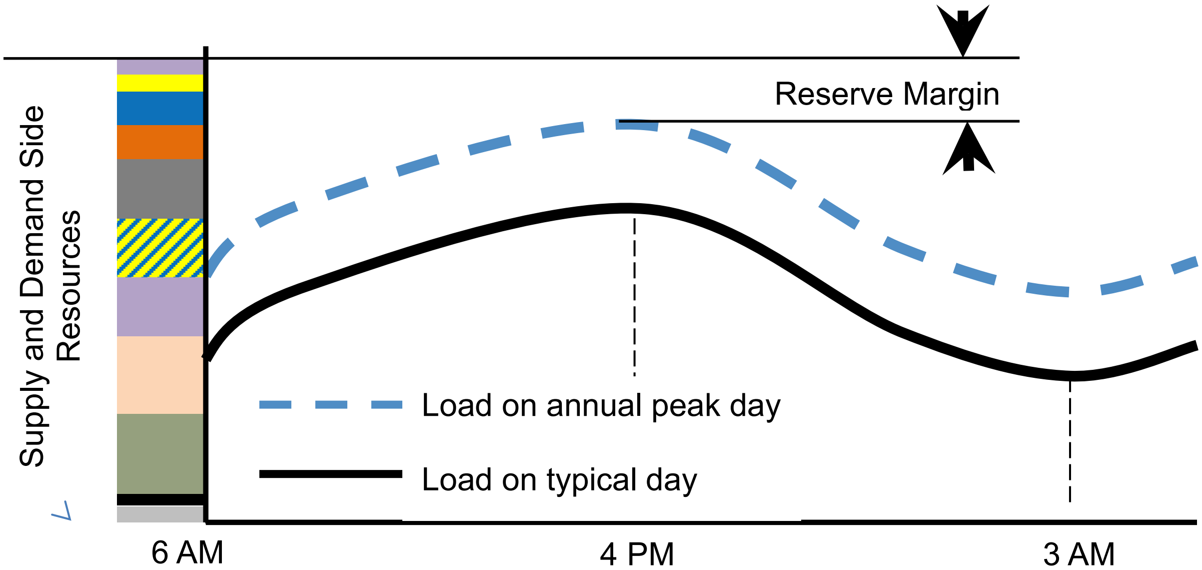


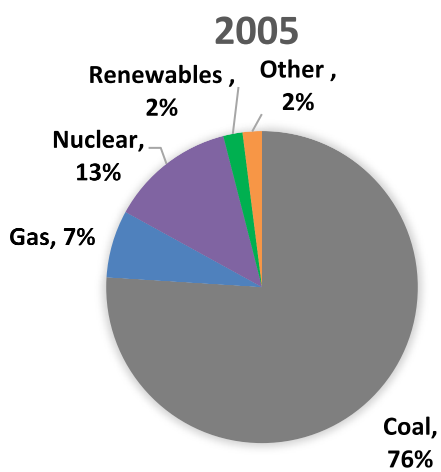
Figure 5-3 – Historic MISO PRMR

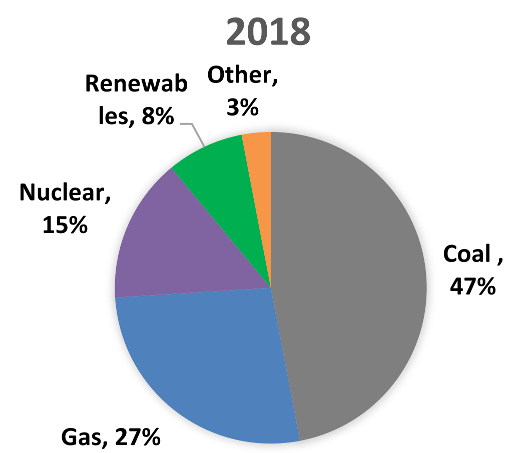
Planning Year	MISO PRMR (UCAP)-Required	MISO PRM (UCAP)-Excess Available: Offered/PRMR
2022-23	8.70%	136,906/135,326: 1.17%
2020-21	8.90%	142,082/135,960: 4.50%
2019-20	7.90%	142,082/134,743: 5.45%
2018-19	8.40%	141,781/135,179: 4.88%
2017-18	7.80%	142,146/134,753: 5.49%
2016-17	7.60%	141,524/135,483: 4.46%
2015-16	7.10%	145,861/136,359: 6.97%

5.3 MISO Resource Mix – Past, Current and Future

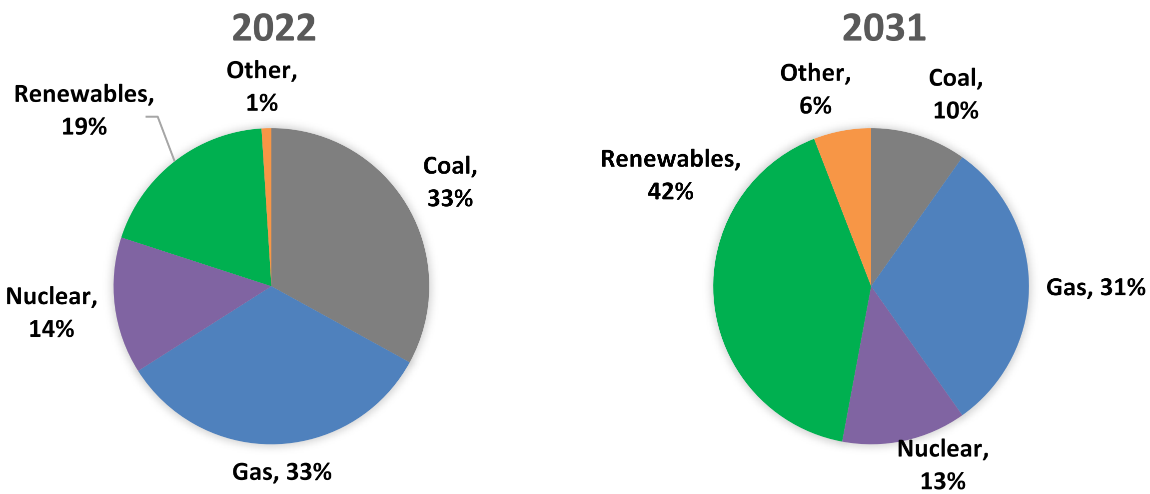
MISO's resource fuel mix has changed drastically since its market inception in 2005. In 2005, coal was the predominant fuel source, with MISO lacking diversity and nuclear as the closest competitor at 13%. In 2018, after the implementation of MATS, the release of the Clean Power Plan and various other regulations, and due to increasing cost pressure from low gas price and declining renewable energy prices, MISO member companies began retiring aging coal units. As a result, its share of the MISO fuel mix dropped to 47%, with natural gas becoming the second leading fuel source and renewables quadrupling in size. In 2022 natural gas and coal (33%) are the leading fuel sources in MISO, followed by renewables (19%), while nuclear has decreased to 14%. MISO now projects by 2031 renewables will be the leading fuel source of MISO energy at 42%, followed by gas at 31% and coal decreasing to 10%.

Figure 5-4 – MISO Fuel Mix[27]





[27] Sources: 2005 Mix: MISO Evolution of the Grid presentation on 11/07/17; page 4 https://ccaps.umn.edu/documents/CPE-Conferences/MIPSYCON-PowerPoints/2017/GenTheEvolutionoftheGridintheMidcontinentIndependentSystemOperator(MISO)Region.pdf
2018 Mix: MISO 2019 MTEP https://cdn.misoenergy.org/MTEP19468493.zip
2022 Mix: MISO Corporate Fact Sheet accessed 04/23 https://www.misoenergy.org/about/media-center/corporate-fact-sheet/
2031 Mix: MISO 2022 Regional Resource Assessment – November 2022 – Page 6 https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf



[28]

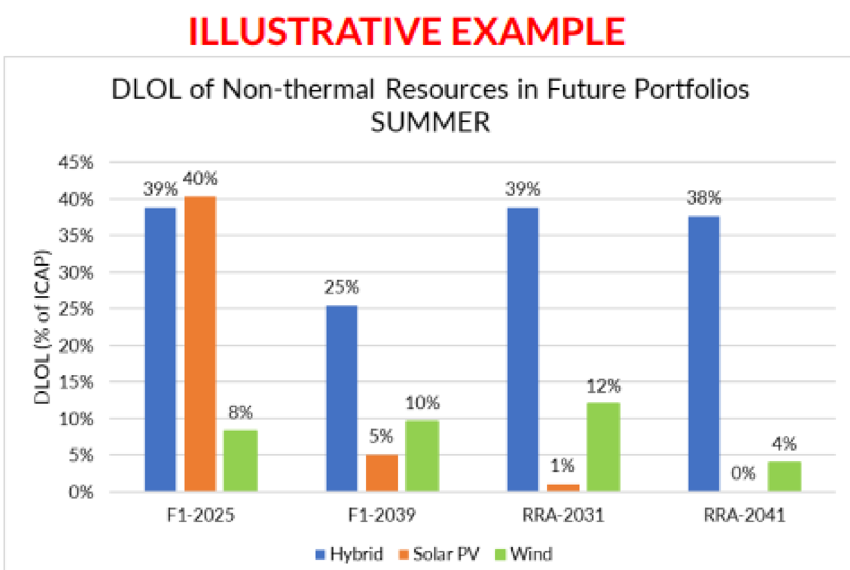
5.4 Dispatchable vs. Intermittent

Dispatchable generation refers to sources of electricity that can be used or dispatched on demand at the request of the power grid operator. Intermittent generation is associated with renewable forms of electricity, mainly solar and wind, which cannot be dispatched at a moment's notice and without storage capabilities only generate electricity as available. Dispatchability of a generation resource allows for planning that is reflected in capacity accreditation, which provides a generator an annual value based on: demonstrated generator capability and the past three years of operational availability during the periods of highest risk and greatest need (resource adequacy hours). Lack of dispatchability creates planning challenges best illustrated through the recent increase in MISO Emergency Max-Gen Events that have occurred throughout the four seasons as the reliance on intermittent resources has increased. An intermittent resource that may be capable of 100% of nameplate generating capacity on a certain day may be reduced to 0% of capacity during another hour of that same day due to a weather pattern. This volatility of intermittent renewable resources has challenged grid planners as these resources have been added to the system. Dispatchable resources that are not on outage remain available as called upon during these severe conditions when intermittent resources do not meet planned output.

[28] Values are presented by MISO total 102%

MISO has shifted from 96% dispatchable generation (all forms of generation except renewables) in 2005 to approximately 76%[29] currently and is forecasted to be greater than 40%[30] renewables in 2031. In response to these conditions MISO commenced its Resource Availability and Need ("RAN") Initiative and its Renewable Integration Impact Assessment ("RIIA") to plan market rule changes to deal with the future resource mix. The RAN Initiative is aimed at better accrediting generation units while the RIIA is focused on understanding the impacts of renewable energy growth in MISO over the long term and assessing potential transmission solutions to mitigate them. While MISO continues to evaluate methodologies for future intermittent resource accreditation, it has signaled accreditation will likely decline over time, particularly for solar resources, as more renewable resources are brought into service. Figure 5.5 shows a recent slide presented in the MISO Resource Adequacy Subcommittee ("RASC"), which provides some possible direction for how non-thermal resources may be accredited in the future.

Figure 5-5 – Direct Loss of Load of Non-Thermal Resources[31]



[29] MISO Corporate Fact Sheet accessed 04/23 - https://www.misoenergy.org/about/media-center/corporate-fact-sheet/

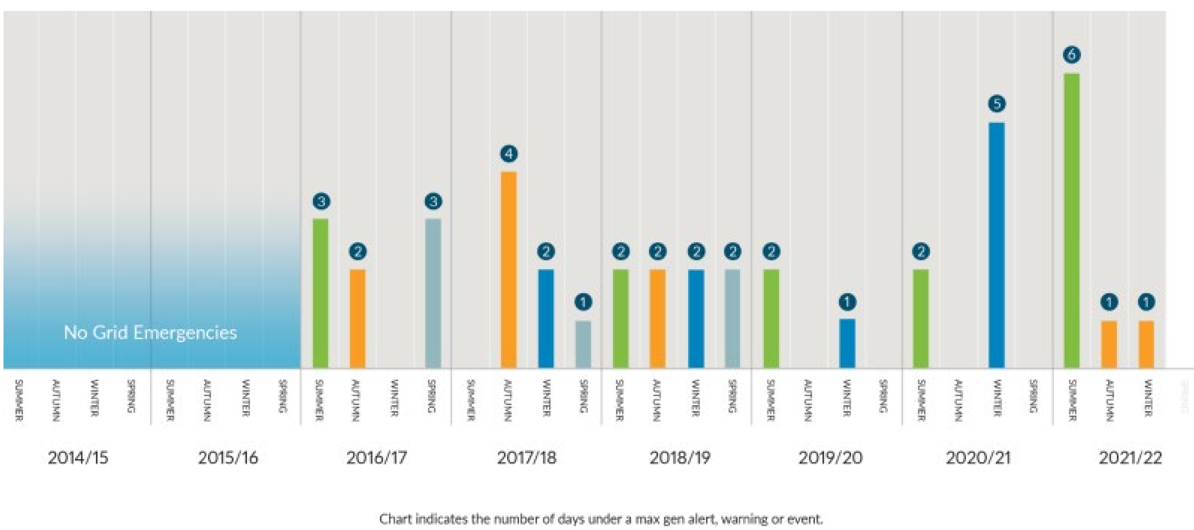
[30] 2022 Regional Resource Assessment – November 2022 – Page 22 - https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf

[31] MISO; March 1, 2023 Resource Adequacy Subcommittee – Market Redefinition: Accreditation Reform; Page 12 - https://cdn.misoenergy.org/20230228-0301%20RASC%20Item%2009a%20Non-Thermal%20Accreditation%20Presentation628030.pdf

5.5 MISO Maximum-Generation Emergency Events

Maximum-Generation ("Max-Gen") Events are the final step in MISO's emergency operating procedure before firm-load shed, otherwise known as blackouts. Max-Gen Declarations have become more common over the last 6 years as shown in Figure 5.6. In January of 2019, MISO, for the first time in its existence, interrupted energy service to Industrial Customers enrolled as Load Modifying Resources ("LMR"). In recent years MISO's Planning Reserve Auctions has seen a higher percentage of LMRs and are projected to be needed to maintain system reliability during extreme events. Going forward customers enrolled as LMRs must consider the increased possibility of future interruptions. It is likely some LMRs will end their participation due to the heighted risk. Beginning in the 2023/2024 Planning Year LMRs must have a notification time equal to or less than six hours and be capable of being interrupted for: (i) at least the first five(5) times requested in the Summer Season; (ii) at least the first five (5) times requested in the Winter Season; (iii) at least the first three (3) times requested in the Spring Season; and at least the first three (3) times requested in the Fall Season.

Figure 5-6 – MISO Max Gen Declarations Over the Past 6 Years[32]



32 https://cdn.misoenergy.org/2021-11-30_RAN%20Seasonal%20Construct%20and%20Availability%20based%20accreditation608310.pdf - Midcontinent Independent System Operator, Inc.'s Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct – November 30, 2021 – Page 3

5.6 MISO Resource Adequacy Reform

As a reaction to the increasing frequency, duration and ability for Max-Gen Events to occur within all periods of the year, MISO implemented its RAN initiative. The goal of this initiative is to identify near-term solutions to increase the conversion of committed capacity resources into energy during times of need. A dramatically changing landscape has made this conversion process challenging. Therefore, MISO and its stakeholders identify and meet the challenges that guide longer-term preparations and near-term enhancements posed by current and future portfolio and technology changes facing the region.

The RAN initiative has led to market mechanism reform which is currently underway. Such reform has included implementation of a sub-annual resource adequacy construct consisting of four separate seasonal reserve margin targets and capacity auctions to better reflect variation in capacity accreditation and capacity needs across the year. Figure 5.7 below shows the PRMR by season for the 2023/2024 planning year.

Figure 5-7 – PRMR for the 2023/2024 Planning Year

Planning Season	MISO PRMR Required (SAC)[33]
Summer	7.4%
Fall	14.9%
Winter	25.5%
Spring	24.5%

The construct is predicated on four three-months seasons accounting for special attributes such as winter weatherization which will allow the capacity resources "must offer" requirement to be applied only to the seasons for which the capacity resource is

[33] MISO Planning Year 2023-2024 Loss of Load Expectation Study Report – Page 4 – May 3, 2023 https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf

cleared to allow units to operate seasonally. Concurrently MISO revised its (thermal) resource accreditation to reflect real-time availability and seasonal performance of generation assets to mitigate reliability risks while improving coordination of planned outages. The revisions process includes a two-tiered weighing approach to emphasize availability during tight critical need periods (Tier 2) but also availability in non-tight hours (Tier 1).

In the 2023-2024 planning year MISO transitioned from its existing annual construct to a four season construct to help ensure system needs are met in all seasons, and hours, of the year. In this new construct resource accreditation, peak demand, and planning reserve margin vary from season to season. CEI South integrated MISO's seasonal construct into the IRP analysis to ensure resource adequacy requirements were met in all seasons with limited capacity purchases over the planning period

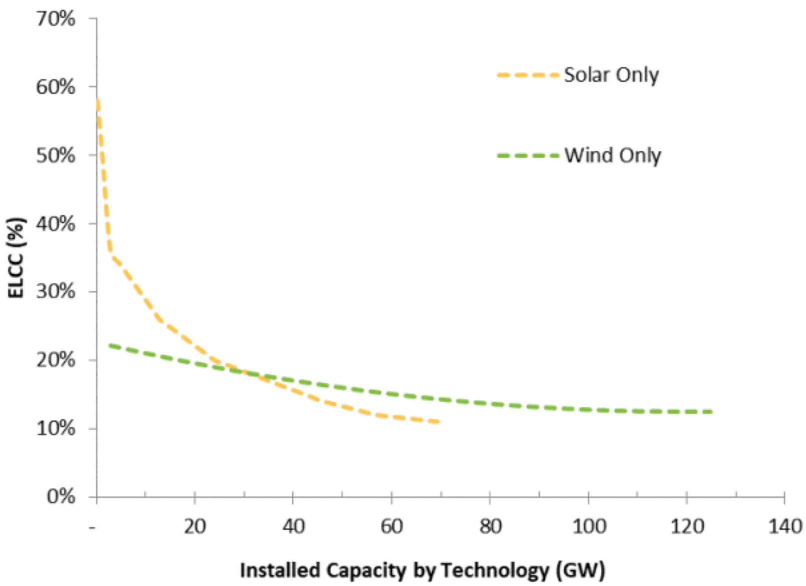
Due to the growth of variable, energy-limited resources in the MISO footprint, along with changing weather impacts and operational practices, MISO determined its existing accreditation methods for non-thermal resources require further evaluation to ensure the accredited capacity value reflects the capability and availability of the resource during periods of highest reliability risk. MISO has developed a proposal that is currently under review by stakeholders which recommends accrediting wind and solar resources based on performance during Resource Adequacy Hours (65 hours in any season during which the capacity is tight. Sixty-five is the top 3% of the total hours (2190, 8760 divided by 4) in any given season) and adjusting unit accreditation to a class capacity value that is derived by using the Direct-Loss of Load ("Direct-LOL") method (taking a generation resource's availability during Loss of Load ("LOL") hours and average the output, using the sum of average availability for the entire resource class). MISO plans to file a final recommendation to FERC in Q4 2023.

5.7 MISO CAPACITY CREDIT

Each resource option receives varying amounts of capacity credit towards MISO's resource adequacy requirement based on their ability to reliably contribute energy during the peak hours in each season. Thermal generation, such as natural gas and coal-fired power plants, can produce an expected level of output when called upon. For this reason, utilities can count nearly the full installed capacity of thermal generation towards their resource adequacy requirement (less their historical outage rate). A new thermal generator can count ~90 MWs out of every 100 MWs of installed capacity towards meeting MISO's planning reserve margin requirement in all seasons. Renewable wind and solar resources are variable sources of power (available when the wind blows or the sun shines), which means they are not always available to meet peak demand. Because neither wind nor solar resources tend to reliably provide their full installed capacity at the peak demand hour, they receive less capacity credit.

While renewable wind resources produce a lot of renewable energy over the course of the Planning Year, their capacity accreditation is typically a lot lower than dispatchable generation. MISO calculates the capacity which will be accredited for wind resources by calculating the resources' Effective Load Carrying Capability ("ELCC"). Wind resources located in MISO Zone 6 receive a capacity credit of only ~8%-~20% for the summer and winter respectively, meaning for every 100 MWs of installed wind capacity, 8 MWs count toward meeting the summer planning reserve margin and 20 MWs would count towards meeting the winter planning reserve margin. As part of MISO's RIIA, MISO evaluated the ELCC of wind and solar resources as penetration levels increased. Renewable penetration is expected to increase as shown in Figure 5.4. Renewable penetration increasing results in the net peak load shifting. This shift results in lower renewable energy production coincidence with the net peak load and therefore a lower ELCC accreditation as seen in Figure 5-8.

Figure 5-8 – Decreasing Solar and Wind ELCC as More is Installed[34]

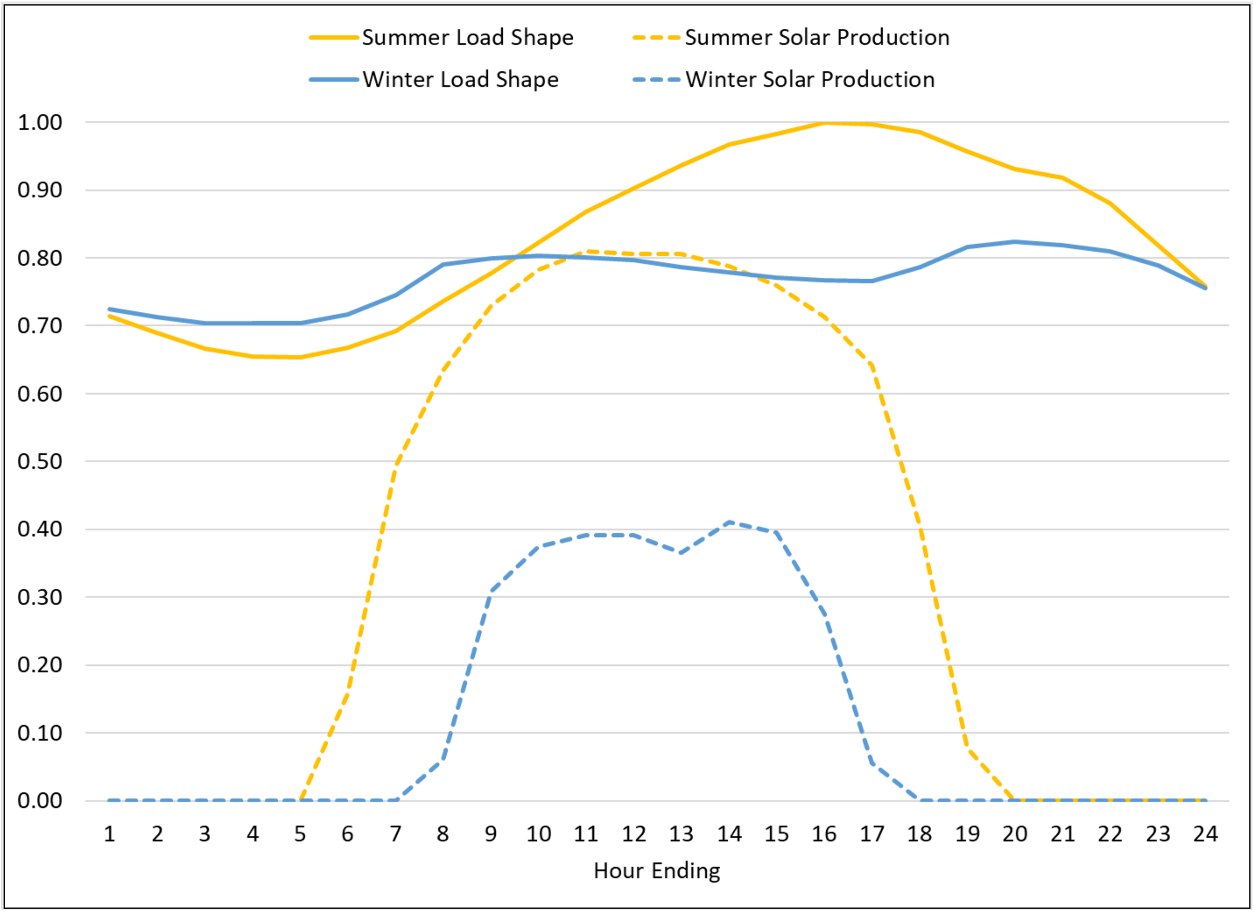


The solar and wind accreditation used in the IRP modeling was calculated using MISO's ELCC accreditation formulas and adjusted based upon the level of renewable penetration expected on MISOs system. As additional renewable resources were included in the model the UCAP accreditation for these resources was adjusted. Over time, this results in lower accreditation values.

Wind and solar capacity factors and energy coincidence with the net peak load vary seasonally. A Solar PV production chart comparison for the winter and summer is shown in Figure 5-9. It shows solar output has a higher coincident with peak demand in the summer months than winter months, due to not only the lower winter solar production, but also the typical peak demand occurring during non-daylight hours. These combined effects result in lower solar winter capacity accreditation.

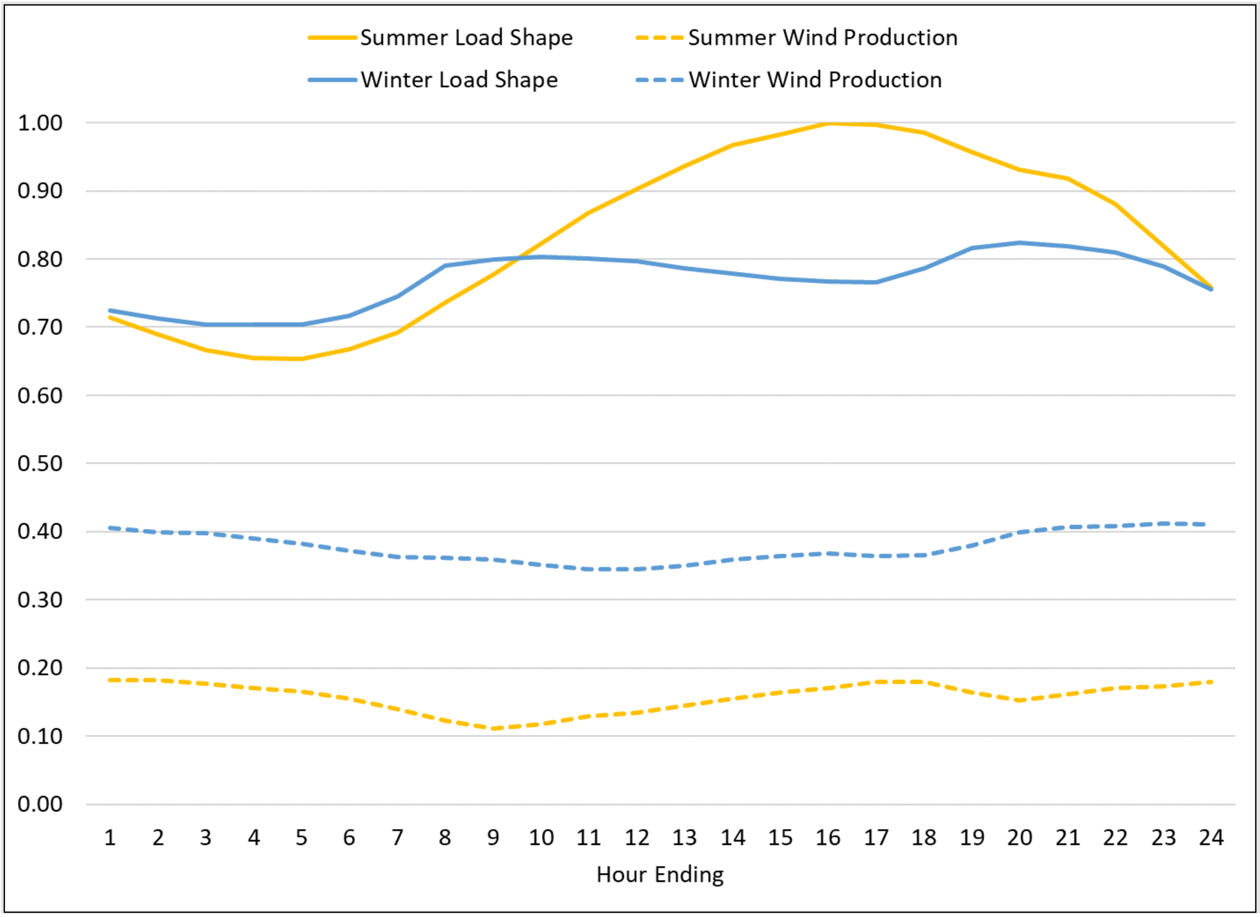
[34] MISO's Renewable Integration Impact Assessment (RIIA) Summary Report February 2021, MISO, page 29, https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

Figure 5-9 – Average Solar PV Energy Production Summer Verses Winter



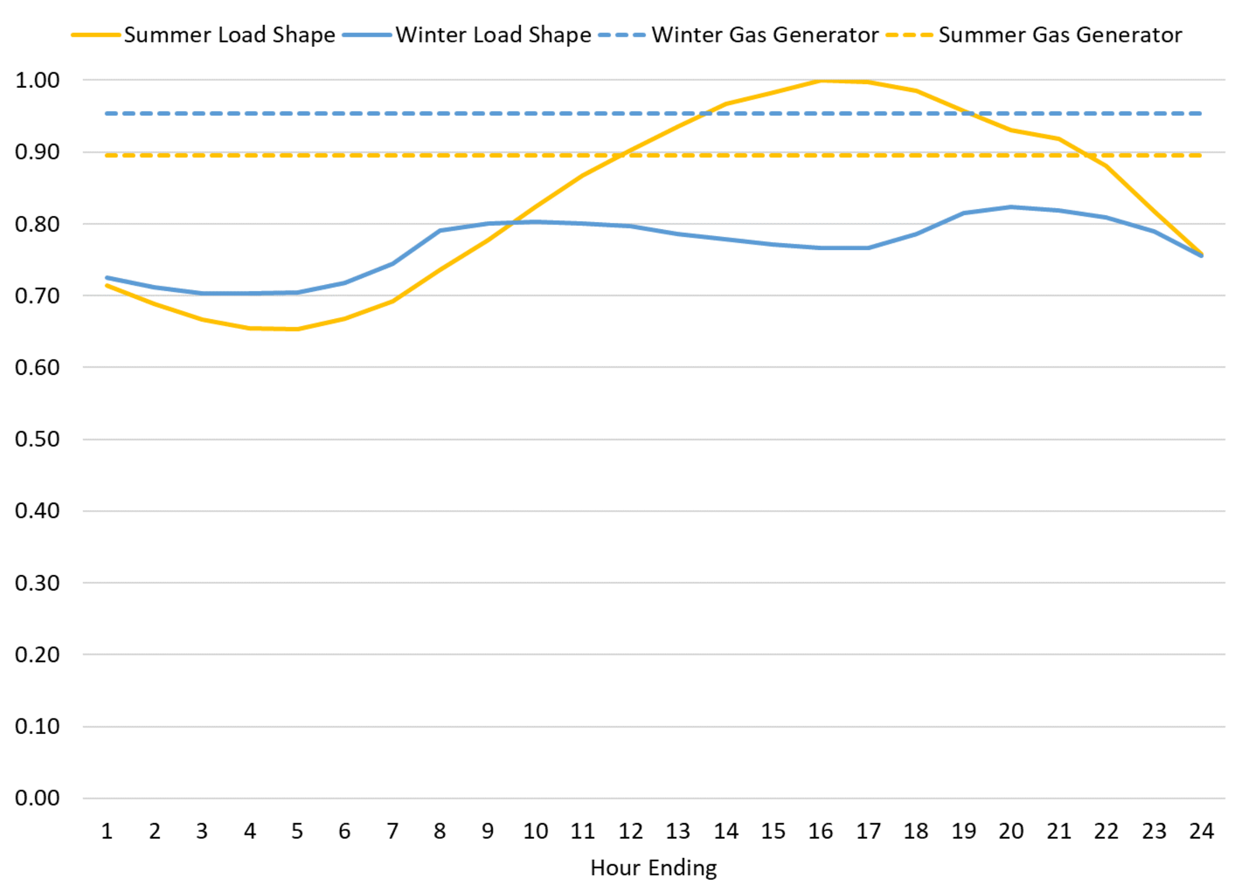
Wind resources typically have higher capacity factors during winter months leading to a higher output during winter peak demand hours. Summer and winter wind production compared to load shapes are shown in Figures 5.10.

Figure 5-10 – Average Wind Energy Production Summer Verses Winter



Gas resources are dispatchable generation; the benefit from being able to turn on and off as needed with exception to unit outages results higher capacity accreditation than non-dispatchable intermittent resources. For reference, a typical gas resource seasonal capability difference is shown in Figure 5-11.

Figure 5-11 – Average Gas Resource Energy Production Summer Verses Winter



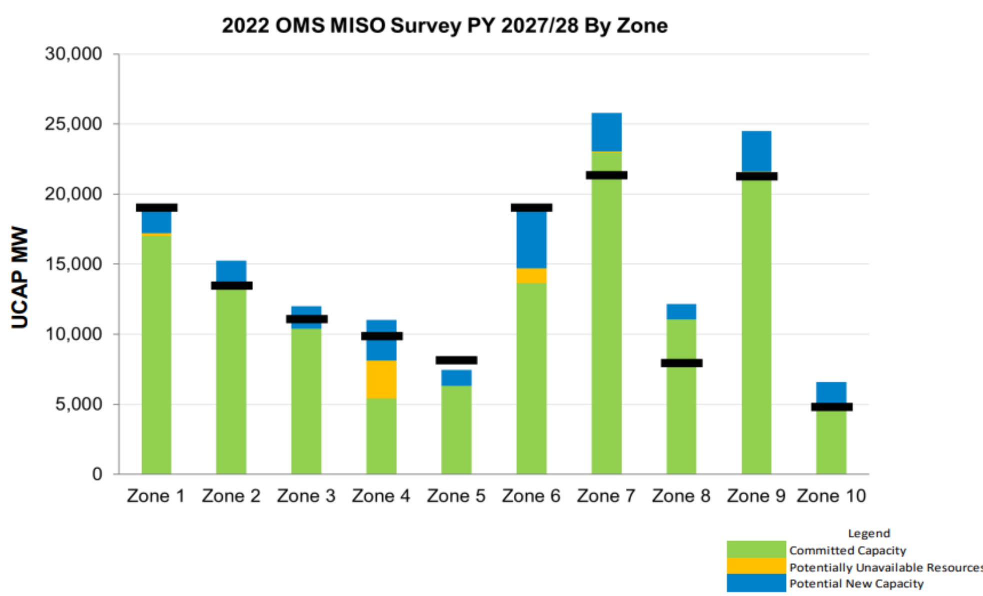
MISO has moved to a seasonal PRMR requirement, as discussed in Section 5.6, and therefore resources as part of this IRP have been accredited on a seasonal capacity credit basis.

5.8 MISO Capacity

Historically, the price for capacity in MISO's annual auction has been volatile. The Organization of MISO States ("OMS"), of which the IURC is a participant, and MISO partnered to better understand future resource needs. Since June of 2014, MISO and the OMS have compiled Resource Adequacy survey responses from MISO members that indicate the need for more supply and demand side resources to meet expected load. This survey has functioned as the main vehicle in communicating to the MISO stakeholder community the anticipated PRM for upcoming years and is a tool in determining whether additional action is needed.

Since its inaugural survey, MISO has warned there may be inadequate capacity within the MISO footprint at some future date which became reality in the 2022-2023 auction with a clearing price set at CONE, the maximum clearing price. OMS-MISO Resource Adequacy survey results have shown projected shortfalls for high certainty resources in the MISO region and Zone 6, which includes most of Indiana and a small portion of Kentucky. Figure 5.12 illustrates Zone 6's increasing proportion of the entire MISO region shortfall projection and thus increased reliance on neighboring state generation resources. To increase the accuracy of the projection, the OMS and MISO have updated the methodology to project which resources are considered high certainty. With these improvements in place since 2017, there is still a projected shortfall. This shortfall is concerning, especially from a zonal standpoint that shows an increasing number of zones projecting a capacity shortfall.

Figure 5-12 –OMS MISO Resource Adequacy Survey Results Graph



According to the latest OMS survey, Indiana Zone 6 is one of the zones most at risk of a shortfall with a projected capacity deficit of approximately 4 GWs in the 2027-2028 planning year. It is worth noting MISO stated in the 2022-2023 PRA Results presentation "Unless more capacity is built that can supply reliable generation, shortfalls such as those highlighted in this year's auction will continue." [35] The conversion of F.B. Culley 3, two existing CTs, and the addition of two fast-start, quick ramping CTs to natural gas will continue to provide the reliable capacity MISO and CEI South's customers need to support the build out of renewable resources. The table below demonstrates the projected shortfall for the MISO region and Zone 6 has more than doubled since 2018.

Figure 5-13 –OMS MISO Resource Adequacy Survey Results Table

OMS-MISO Resource Adequacy Survey Results by Year	Zone 6 Resource Adequacy Shortfall, 5-Year Projected	MISO-wide Resource Adequacy Shortfall, 5-Year Projected
2014	No 5-year projection provided	5.8 GW shortfall in 2019
2015	1.1 GW shortfall in 2020	2.3 GW shortfall in 2020
2016	800 MW shortfall in 2021	2.6 GW shortfall in 2021
2017	400 MW shortfall in 2022	No shortfall projected
2018	1.6 GW shortfall in 2023	4.5 GW shortfall in 2023
2019	2.4 GW shortfall in 2024	2.3 GW shortfall in 2024
2020	3.4 GW shortfall in 2025	6.8 GW shortfall in 2025
2021[36]	3.9 GW shortfall in 2026	0.8 GW shortfall in 2026
2022	≈4 GW shortfall in 2027	10.9 GW shortfall in 2027

5.8.1 Capacity Prices

The projected capacity shortfalls can result in volatile capacity prices. MISO's Planning Resource Auction ("PRA") is held annually for each of the load zones within the MISO footprint to ensure sufficient capacity resources. The PRA has yielded a wide fluctuation in capacity pricing for Zone 6 since its inaugural year of 2013, as shown in Figure 5.14 below. These large swings in prices have made it difficult to forecast forward year prices.

[35] 2022-2023 MISO PRA Results - https://cdn.misoenergy.org/20220610%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation625148.pdf – Page 11

[36] Prior to 2021 MISO showed capacity position on an ICAP basis; In 2021 MISO switched to a UCAP basis

While the 2020-2021 capacity price was relatively low, all zones in MISO's north/central region cleared at CONE ($236.66/MW-Day) in the 2022-2023 PRA.

Figure 5-14 –MISO Capacity Prices

Planning Year	Highest Clearing price for MISO-region	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/day[37]	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/year	Year-over-Year Price Change
2013-2014	$1.05	$1.05	$383.25	-
2014-2015	$16.75	$16.75	$6,113.75	1,495% Increase
2015-2016	$150.00	$3.48	$1,270.20	79% Decrease
2016-2017	$72.00	$72.00	$26,280.00	1,969% Increase
2017-2018	$1.50	$1.50	$547.50	98% Decrease
2018-2019	$10.00	$10.00	$3,650.00	567% Increase
2019-2020	$24.30	$2.99	$1,091.35	70% Decrease
2020-2021	$257.53	$5.00	$1,825.00	67% Increase
2021-2022	$5.00	$5.00	1,825.00	No Change
2022-2023	$236.66	$236.66	86,380.90	4,633% Increase

As shown in Figure 5.15, the inaugural 2023-2024 seasonal PRA zone 6 cleared at $10.00 in the summer, $15.00 in the fall, $2.00 in the winter, and $10.00 in the spring, all in $/MW-Day. While prices cleared lower in the 2023-2024 auction when compared to the 2022-2023 auction, MISO noted in the presentation of 2023-2024 PRA results that delayed retirements and market participants making additional existing capacity available contributed to sufficient capacity being available for the auction. MISO also noted many of these actions may not be repeatable and the residual capacity and resulting prices do not reflect the risks posed by the portfolio transition.[38]

Figure 5-15 –Inaugural MISO Seasonal Capacity Prices

Planning Year	Highest Clearing price for MISO-region per MW-Year	Clearing Price for Zone 6 (Indiana & Kentucky) per MW-day	Clearing Price for Zone 6 (Indiana & Kentucky) per MW-year
Summer	$3,650	$10	$3,650
Fall	$21,612	$15	$5,475
Winter	$6,891	$2	$730

[37] MW/day is the amount customers are required to pay should they purchase capacity via the MISO Planning Resource Auction. For example, in the 2016-2017 planning year each MW cost $72 per day ($26,280 per MW annually).

[38] https://cdn.misoenergy.org/2023%20Planning%20Resource%20Auction%20(PRA)%20Results628925.pdf – MISO Planning Resource Auction Results – May 19, 2023 – Pages 3 and 4

Spring	$3,650	$10	$3,650

MISO and the Independent Market Monitor have determined the absence of a sloped demand curve in the PRA results in inefficient market outcomes and inefficient price signals. In addition, they have warned the current vertical demand curve in the PRA has consistently produced clearing prices that are divorced from the marginal value of reliability and the capacity needs of the region. To ensure reliable grid operation by having adequate resources procured in a cost-effective manner MISO has proposed a Reliability Based Demand Curve ("RBDC") which will capture the incremental capacity above the planning reserve margin requirement reflecting the reliability value.

5.9 MISO Energy Prices

Energy prices in MISO increased significantly in 2022 but have since trended down closer to recent historical norms. Several weather-related events, a capacity shortfall in MISO's North Central region and elevated coal and gas prices combined to create volatile energy prices. In 2023 the natural gas reserves have grown, pushing down costs, resulting in more stable energy prices in the MISO market.

Figure 5-16 –MISO Clearing Prices (Indiana Hub/Henry Hub Yearly Averages – 2015-YTD April 2023)

Year	Indiana Hub Real Time ATC Average	YoY% Change	Indiana Hub Day Ahead ATC Average	YoY% Change	Henry Hub Average	YoY% Change
2015	$28.02		$28.67		$2.61	
2016	$27.94	-0.27%	$28.11	-1.94%	$2.49	-4.60%
2017	$29.30	4.86%	$29.38	4.50%	$2.96	19.10%
2018	$32.99	12.59%	$33.19	12.97%	$3.12	5.36%
2019	$26.41	-19.95%	$26.98	-18.72%	$2.51	-19.41%
2020	$22.30	-15.55%	$22.97	-14.86%	$2.03	-27.05%
2021	$39.45	76.9%	$41.21	79.45%	$3.89	91.63%
2022	$71.47	81.18%	$70.22	70.37%	$6.45	65.81%
YTD 2023	$31.17	-56.39%	$32.54	-53.66%	$2.53	-60.78%

Over time, it is expected natural gas prices will increase, but remain relatively low and stable, keeping energy prices low.

5.10 MISO Interconnection of New Resources

Before a new generating facility can connect to the grid, the reliability impacts associated with interconnection must be studied. Issues uncovered during this process can be mitigated through electric transmission Network Upgrades ("NU"). The addition of upgrades to address system reliability have the potential to increase the costs associated with a new generating facility.

The MISO Generator Interconnection ("GI") process is a three-phase study cycle that has historically been conducted once or twice annually but as the size of the queue has grown, the process has slowed.

The Generator Interconnection Process (GI) defines the steps an interconnection customer and MISO take to move interconnection requests through the interconnection queue. The process can result in an interconnection agreement that allows the customer to connect generation to the MISO grid. The Generator Interconnection Process (GI) is divided into three phases: Pre-Queue, Application Review and Definitive Planning.

The Definitive Planning Phase (DPP) is the final phase of MISO's generator interconnection study process, during which MISO conducts reliability and deliverability studies that determine whether there is available transmission capacity to accommodate the interconnection of a new, proposed generation facility or whether network upgrades are needed. Application and milestone payment requirements based on the size of the unit to be studied are required 45 days prior to the start of the study cycle.

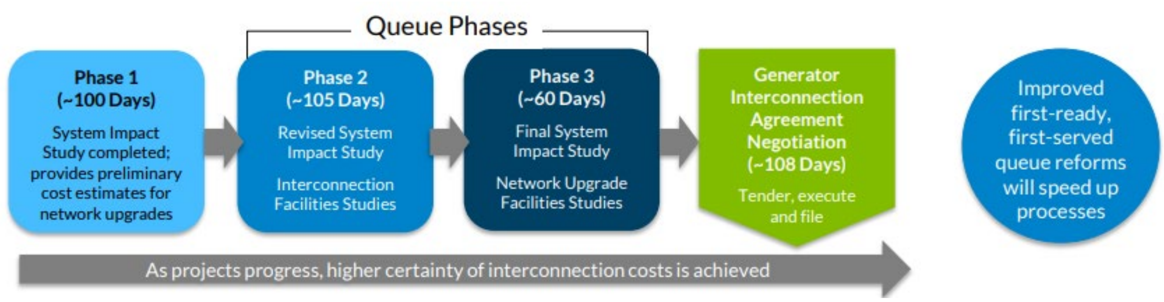
The DPP process is broken down into three phases and two decision points, following the completion of the first two phases (studies) the interconnection customer will once again have the chance to adjust the project size and move to the next phase as well as to withdraw from the queue. Upon completion of the third DPP, MISO and the GI requestor begin the GI Agreement ("GIA") process. Upon satisfying all terms of the GIA, the GI requestor will receive a fully executed GIA that enables the generator to connect to the

MISO transmission system and depending on the transmission service selected, participate, and receive full accreditation in the MISO energy and capacity markets.

On March 15, 2022, MISO gained FERC's approval for a reduced Generator Interconnection Process ("GIP") timeline that decreased the time it takes to process interconnection study request from 505 calendar days to 373 days. Despite this approval, the MISO Generator Interconnection Queue process ("GIA/DPP") is experiencing significant schedule delays causing a great deal of uncertainty for interconnecting customers. Historically, MISO has only seen about a 20% success rate of all projects requesting interconnection, leaving customers entering the queue little certainty regarding interconnection cost or the timing for achieving deliverability, thus 80% of interconnection requests withdrawn from the queue. MISO acknowledges the current process is simply too long and will continue to work with stakeholders on interconnection process reforms.

As increased renewable development continues in order to qualify for tax incentives before expiration, the number of GI requests is not expected to subside and as a result, the timeline is likely to remain delayed.

Figure 5-17 –Reduce GIP Timeline (DPP Process)[39]



[39] MISO; https://cdn.misoenergy.org/20221206%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2004%20Generator%20Interconnection%20Queue%20Update627220.pdf; Generator Interconnection Queue Update, System Planning Committee of the Board of Directors, December 6, 2022; page 6

GI costs are determined based on the MW impact from each project on identified constrained facilities. As such, cost allocation is assigned to the generator that causes or contributes to a constraint and therefore projects that are studied after prior cycles are more likely to have additional costs identified. More simply stated, the earlier a project gets in the queue, the more likely it is to utilize any available transmission capacity at lowest cost. Conversely, projects that request studying in later cycles are more likely to be assigned higher costs as a result of prior projects connecting to and exhausting current transmission system topology. For this reason, existing interconnection rights are valuable. MISO allows for an expedited process for new generation with existing interconnection rights; this helps to shield customers from potential upgrade costs. CEI South has continued the interconnection transfer process at A.B. Brown coal units 1&2 to new combustion gas turbine units 5&6. This process is anticipated for F.B. Culley 3 from a coal unit to one that is fired by gas. Bypassing the interconnection queue decreases timing and cost risk for CEI South customers.

SECTION 6
RESOURCE OPTIONS

6.1 ALL-SOURCE RFP

The All-Source RFP was conducted according to the schedule outlined in Figure 6.1. More details on the steps included in the RFP timeline are described below.

Figure 6-1 RFP Timeline

Step	Date
RFP Issued	Wednesday, May 11, 2022
Notice of Intent, NDA, and Respondent Application Due	5:00 p.m. CDT, Friday, May 27, 2022
Pre-Bid Meeting	3:00 p.m. CDT, Wednesday, June 1, 2022
Proposal Submittal Due Date	5:00 p.m. CDT, Tuesday, July 5, 2022
Initial Proposal Review and Evaluation Period	Wednesday, July 6, 2022 – Thursday, August 11, 2022
Proposal Evaluation Completion Target and Short List to CenterPoint	Friday, August 12, 2022
Due Diligence and Negotiations Period	Q3-Q4 2022

6.1.1 RFP Issued

1898 & Co. issued the All-Source RFP on behalf of CEI South on Wednesday, May 11, 2022 (http://CenterPoint2022ASRFP.rfpmanager.biz/). Notice was sent to all known IRP stakeholders and posted on www.midwest.centerpointenergy.com/IRP. The RFP was advertised across multiple media outlets, including, North American Energy Markets Association ("NAEMA") (190 members) and Midwest Energy Efficiency Alliance ("MEEA") Minute (161 members). It was also sent directly via e-mail to participants of CEI South's 2019 All-Source RFP, an internal 1898 & Co. RFP contact list (more than 900 recipients), and CEI South industry contacts. Several industry publications, including S&P Global, also published articles about the RFP. While the RFP included general requirements and communicated Proposals which do not meet the general requirements may be subject to disqualification, all were included for evaluation. For more details, please refer to the submitted CEI South 2022 All-Source RFP in Technical Appendix Attachment 6.3.

6.1.2 Notice of Intent

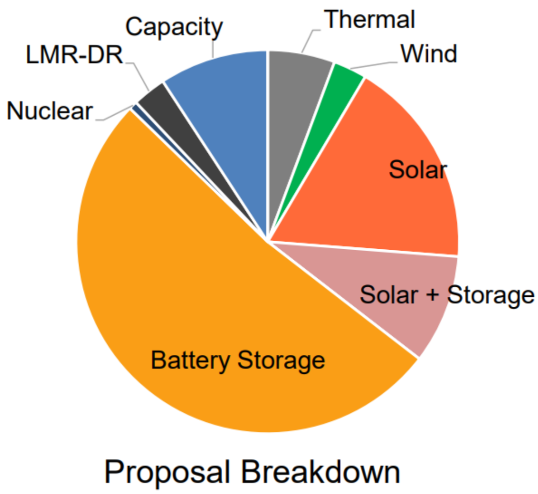
Respondents were given two weeks to submit a Notice of Intent to participate in the RFP process, sign the Non-Disclosure Agreement and complete the Pre-Qualification Application. The purpose of the Pre-Qualification Application is to verify Respondents have adequate experience and financial capability to support their Proposal(s).

6.1.3 Proposal Review

The Proposal Submittal Due Date was Tuesday, July 5, 2022. After all Proposals were received, 1898 & Co. began the Initial Proposal Review. While Proposals were being reviewed, information was clarified with Respondents to confirm Proposals were interpreted as intended.

A total of 142 Proposals were received from 29 Respondents. The Proposals comprised 62 battery storage, 5 thermal, 4 LMR/DR, 42 solar, 15 solar plus storage, 4 wind, 9 capacity only, and 1 thermal plus solar. Of the 142 Proposals, 108 were in Indiana. The Proposals contained approximately 20 GW of total installed capacity; however, many of the projects were included in multiple proposals. There was approximately 7.5 GW of unique project installed capacity after accounting for double counting. For example, a single 100 MW solar project could be offered as a purchase option or various PPA options. A graphical overview of all Proposals received is shown in Figure 6-2.

Figure 6-2 Breakdown of Proposals Received



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

6.1.4 Proposal Updates for Inflation Reduction Act (IRA)

Shortly after Proposals were submitted for the 2022 All-Source RFP, the IRA was passed into law on August 16, 2022. This law provided additional tax structures and incremental benefits for renewables and other energy projects that met certain criteria. To determine the pricing impact, participants in the RFP were asked to update their proposals on August 23, 2022 and have them resubmitted no later than September 7, 2022. Of the 142 Proposals, 77 were resubmitted with updated pricing to account for the IRA. Of the submitted bids, storage PPA's saw an average price decrease of 13%, solar PPA's 8% decrease, Solar plus storage PPA's 4% decrease, and wind PPA's 14% decrease.

6.1.5 MISO Interconnection

The appropriate MISO DPP Generation Interconnection Study Group was identified for each of the respective Proposals. For the Proposals that reside in Study Groups with posted DPP reports, the identified NU and associated costs were used.

For the Proposals that reside in Study Groups without posted DPP reports, the RFP asked for the bidder's estimate of interconnection costs, but these were not used in evaluation between Proposals to preserve objectivity in the comparison.

6.1.6 Grouping

Proposals were divided into groups based on technology type and ownership structure. Aggregated cost and performance information from the RFP Proposals was provided to the IRP team to facilitate portfolio modeling. There are many benefits to modeling the RFP bids in groups. These benefits include allowing the IRP modeling to help evaluate the technology, size, duration and mix of resources which would be included in the Preferred Portfolio. Given the volume of Proposals received as part of the IRP, it may not have been possible and would not have been practical to model each individual project. Moreover, it would be difficult to maintain confidentiality of individual projects. IRP modeling of individual projects does not holistically evaluate all relevant factors, such as locational differences of wholesale market pricing and potential congestion impacts. Using a grouping method allows for IRP inputs to reflect anticipated project costs.

6.1.7 Evaluation of Proposals

1898 & Co. quantitatively and qualitatively evaluated all conforming generation facility Proposals. Proposals were evaluated relative to others within the same grouping using the scoring criteria set forth in the RFP. The scoring criteria included four major categories: LCOE, energy settlement location, interconnection/development status and project risk factors.

Scoring of the individual RFP Proposals was not part of the IRP process. Scoring criteria has been provided for transparency to respondents and to demonstrate CEI South is serious about pursuing projects following the completion of the IRP analysis. CEI South does not believe RFPs should be conducted just to obtain market data. The Proposals were scored to aid in the selection process after the Preferred Portfolio results were provided from the IRP. The Proposals were scored according to the criteria shown in Figure 6-3.

Figure 6-3 Scoring Summary

Scoring Criteria Name	Points		Definition/Allocation	Importance
LCOE Evaluation	150		$/MWh Calculation within asset class	An LCOE evaluation comparing similar resource groups will help to show which Project(s) may provide lower cost energy to CenterPoint customers
Energy Settlement Location	100		Proposals that include all costs to have energy financially settled or directly delivered to centerpoints load node. (SIGE.SIGW)	Having Financial settlement or direct delivery to CenterPoints load node provides Project's tru resource cost to CenterPoint's customers, eliminating risks/costs associated with the delivery of energy.
Interconnection and Development Status	100		•75 points completed Facilities Study (during DPP2-3) & offered cost cap •50 points competed System Impact Study (during DPP1) & offered cost cap •25 points offered cost cap •0 points otherwise	These points are for completion of various critical milestones in the interconnection and development process. Projects which are further through the interconnection and development process will receive more points as costs certainty improves.
Project Risk Factor - Renewable	150		•Credit and Financial Plan – 30 points awarded proportional to CNP internal score from 0-10 •Development Experience – 30 points awarded proportional to MW in service, max of 1,500 •Site Control – 30 points proportional from 0%-100% of site control verified by provided docs •Permits – 30 points for proposals showing all permits needed for construction/operation •Zoning – 30 points for proposals showing completed zoning requirements	Certain risk factors may be unique to a Proposal. Such factors may be significant enough to independently impact the overall ability of the Proposal to meet CenterPoint's needs. This category is intended to capture unspecified risk that may be highlighted by a Respondent or identified during the Proposal review. The Project Risk Factors attempt to identify and score potential risks which may compromise the future performance of the asset.
Project Risk Factor - Thermal	150		•Credit and Financial Plan – 30 points awarded proportional to CNP internal score from 0-10 •Development Experience – 30 points awarded proportional to MW in service, max of 1,500 •Fuel Risk - 15 •Operational Control – 15 •Site Control – 30 points proportional from 0%-100% of site control verified by provided docs •Permits – 15 points for proposals showing all permits needed for construction/operation •Zoning – 15 points for proposals showing completed zoning requirements	Operational control provides the ability to make prudent operational decisions when it makes economic sense for CenterPoints customers. Fuel restrictions or lack of reliable fuel could effect the operation of the Project and be a risk to the owner/off taker.

RFP bids were ranked consistent with the evaluation criteria and will be considered based on the RFP evaluation and the IRP determined need. Projects consistent with the IRP have undergone further due diligence and have led to negotiations with bidders. As such, there is no assurance the individual, highest-scoring qualified Proposal(s) will be selected. For further discussion of the evaluation criteria and results see Technical Appendix 6.3.

6.1.8 Challenges with Conducting an All-Source RFP within an IRP

While there are advantages to conducting an All-Source RFP as part of the IRP process, there are several challenges that must be considered, particularly the long lead time. Developers prefer certainty on project selection to minimize project development cost risk. Conducting an RFP as an input to the IRP necessitates a long process. CEI South believes, at a minimum, a year is needed to conduct an IRP analysis. While CEI South asked bidders to keep bids open after bid submittal, this does not mean developers are able to wait until the process is complete.

As a result, some projects may be acquired by other load serving entities since typically individual projects are being bid into multiple utilities' RFPs. Competition for projects in MISO Zone 6 is steep with many utilities (NIPSCO, IPL, Hoosier Energy, IMPA and CEI South) currently all vying for announced projects that have more certainty of being developed.

As a project moves along, several issues can arise that increase cost estimates, including updated engineering identifying new costs, environmental permitting, local pushback, local permitting, updated interconnection costs, updated risk assessments by the developers, etc. On the contrary, the opposite can also happen. Due to the extraordinary market volatility in recent years, the market price of projects has risen significantly since the last RFP. Market uncertainty is also driving developers to price in the high-end of their risk resulting in project pricing that is much higher today than it was even two years ago.

6.2 CURRENT RESOURCE MIX

Generating units are often categorized as either base load, intermediate, or peaking units. This characterization has more to do with the economic dispatch of the units and how much service time they operate rather than unique design characteristics, outside of intermittent renewables, which do not have variable fuel costs. Base load units generally have the lowest energy costs per kWh and tend to operate most of the time, thereby providing the base of the generating supply stack after intermittent renewables, which operate as available and typically unrelated to market prices and conditions. The supply stack is the variable cost of production of power by each generating unit, stacked from least cost to most cost. In general, units that cost less to run are dispatched before units that cost more. CEI South's larger coal units have historically operated as base load units but with low natural gas prices and the introduction of more renewables into the market, capacity factors have decreased. CEI South's coal units more recently have operated more like intermediate units, particularly in shoulder months during Spring and Fall seasons. Intermediate units may cycle on and off frequently and may sit idle seasonally. CEI South's current peaking units have relatively high energy costs per kWh and are typically only started when energy demand exceeds 24/7 baseload capacity. Currently, CEI South's gas turbines are dispatched during these peak periods to assure reliability. These small peaking units may only run for a few hours and remain idle for long periods of time until called on.

CEI South's current generation mix consists of approximately 1,324 megawatts ("MW") of installed capacity. This capacity consists of approximately 995 MW of coal-fired generation, 160 MW of gas fired peaking generation, 3 MW of renewable landfill gas generation, 54 MW of solar, Purchase Power Agreements (PPA's totaling 80 MW from wind), and a 1.5% ownership share of Ohio Valley Electric Corporation ("OVEC") which equates to approximately 32 MW.

Figure 6.4 references both Installed Capacity ("ICAP") and Seasonal Accredited Capacity ("SAC"). Installed capacity is also referred to as nameplate capacity. This is the maximum output that can be expected from a resource. Seasonal accredited capacity is the amount of capacity that can be relied upon to meet load during tight operating hours. MISO now uses SAC for planning purposes. The SAC accreditation recognizes all resources are not equally reliable or, in some cases, capable of achieving their design output. MISO uses a three-year operating history and a weather normalized capability verification to determine the SAC accreditation of each unit. CEI South used historical data and MISO's current methodology for thermal units to determine seasonal accreditation values along with the MISO seasonal planning reserve margin requirements (7.4% for summer, 14.9% for fall, 25.5% for winter, and 24.5% in spring[40]) in the current IRP. This information was utilized to help ensure all portfolios met MISO obligations on a seasonal basis.

[40] Planning Year 2023-2024 Loss of Load Expectations Study Report; MISO; https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf ; Update 5/1/23; page 4

Figure 6.4 – CEI South Generating Units

Unit	Installed Capacity ICAP (MW)	Summer SAC (MW)	Fall SAC (MW)	Winter SAC (MW)	Spring SAC (MW)	Primary Fuel	Year Unit First In-Service
A.B. Brown 1	245	228	N/A	N/A	N/A	Coal	1979
A.B. Brown 2	240	226	N/A	N/A	N/A	Coal	1986
F.B. Culley 2	90	87	90	88	83	Coal	1966
F.B. Culley 3[41]	270	215-270	191-270	199-270	270	Coal	1973
Warrick 4	150	142	150	N/A	N/A	Coal	1970
A.B. Brown 3	80	75	85	85	85	Gas	1991
A.B. Brown 4	80	73	72	76	84	Gas	2002
Blackfoot	3	N/A[42]	N/A[42]	N/A[42]	N/A[42]	Landfill Gas	2009
Oak Hill Solar	2	N/A[42]	N/A[42]	N/A[42][42]	N/A[42]	Sun	2018
Volkman Rd Solar	2	N/A[42][42]	N/A[42]	N/A[42][42]	N/A[42]	Sun	2018
Troy Solar	50	37	25	2	32	Sun	2021

*Installed capacity shown at 59°F

6.2.1 Coal

The A.B. Brown Generating Station ("ABB"), located in Mt. Vernon, Ind., consists of two coal fired units. ABB Unit 1 began commercial operation in 1979, while ABB Unit 2 became operational in 1986. ABB Unit 1 has an installed capacity of 245 MWs and ABB Unit 2 has an installed capacity of 240 MWs. Over the last three years these units have operated at an average capacity factor of approximately 60%.

Both A.B. Brown units are scrubbed for sulfur dioxide ("SO_2") emissions, utilizing a dual-alkali Flue Gas Desulfurization ("FGD") process. The FGD systems were included as part of the original unit design and construction. Sulfur trioxide ("SO_3") is removed via Sodium Based Sorbents ("SBS") injection systems installed on both units in 2015. ABB is also scrubbed for nitrogen oxides ("NO_x") with Selective Catalytic Reduction ("SCR") systems having been installed on Unit 2 in 2004 and on Unit 1 in 2005. Mercury ("Hg") removal is

41 Accreditation was lowered in the near term for Culley 3 to account for the unplanned outage in 2022/2023

42 The Blackfoot landfill gas generator and 2 MW solar installations are connected at the distribution level and are not part of the transmission connected generation network managed by MISO. Therefore, they are not assigned a MISO UCAP value.

accomplished on both units as a co-benefit of SCR and FGD operations as well as through the addition of organosulfide injection systems installed in 2015. Particulate matter ("PM") is captured via an electrostatic precipitator ("ESP") on Unit 2. PM control at Unit 1 was upgraded to a fabric filter in 2004. The PM that is captured, also known as fly ash, is part of CEI South's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, Mo., where it is used in the manufacture of cement.

A.B. Brown Units 1 and 2 burn Illinois basin bituminous coal, which is mined in Knox County, Ind., and is delivered via rail. These units are scheduled for retirement late in 2023.

The A.B. Brown plant site also has two natural gas turbine generators which are discussed in Section 6.2.2, Natural Gas.

The F.B. Culley Generating Station ("FBC"), located near Newburgh, Ind., is a two-unit, coal fired facility. FBC Unit 2 has an installed generating capacity of 90 MW and came online in 1966, while FBC Unit 3 has an installed capacity of 270 MW and became operational in 1973. Over the last three years Unit 2 has operated at an annual capacity factor of 22% while Unit 3 was 48%.

FBC is scrubbed for SO_2 emissions, utilizing an FGD process which is shared by both units and was retrofitted in 1994. The captured SO_2 is converted into synthetic gypsum within the system and, as part of CEI South's beneficial reuse program, is shipped, via barge, to a facility near New Orleans, La., and is shipped via truck to a facility near Shoals, Ind., where it is used in the manufacture of drywall. SO_3 is removed from FBC Unit 3 via a Dry Sorbent Injection ("DSI") system installed in 2015. FBC Unit 3 is also scrubbed for NO_x with a SCR system that was installed in 2003. NO_x control on FBC Unit 2 is provided by low NO_x burners. Mercury removal is accomplished on both units as a co-benefit of SCR & FGD operation as well as through the addition of organosulfide injection systems installed in 2015. PM is captured via an ESP retrofitted on Unit 2 in 1972. Unit 3 was upgraded to a fabric filter for PM control in 2006. The PM that is captured, also known as fly ash, is part of CEI South's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, Mo., where it is used in the manufacture of cement. A Spray Dry Evaporator ("SDE") system was installed in 2023 to comply with the EPA's ELG. This system takes the wastewater stream from the scrubber and separates the solids and then injects the remaining liquid into the flue gas stream where it is evaporated resulting in a zero liquid discharge process.

The F.B. Culley units burn Illinois basin bituminous coal, which is mined in Knox County, Ind., and delivered via truck. F.B. Culley 3 is CEI South's most efficient coal unit.

Warrick Unit 4 (Warrick) located near Newburgh, Ind., is a coal fired unit operated and maintained by Alcoa Power Generating Inc. CEI South maintains 50% ownership of Warrick Unit 4. It has an installed capacity of 300 MW which began commercial operation in 1970. CEI South's 50% interest is equal to 150 MW. Over the last three years this unit has operated at a capacity factor of 70%.

Warrick Unit 4 is scrubbed for SO_2 emissions, utilizing a FGD process which was retrofitted in 2009. The captured SO_2 is converted into synthetic gypsum within the system and (as part of CEI South's beneficial reuse program) is shipped via truck to a facility near Shoals, Ind., where it is used in the manufacture of drywall. SO_3 is removed via a DSI system installed in 2010. Unit 4 is also scrubbed for NO_X with a SCR system which was retrofitted in 2004. Mercury removal is accomplished as a co-benefit of SCR and FGD operation as well as through the addition of organosulfide injection systems installed in 2015. PM is captured via an ESP. The PM that is captured, also known as fly ash, is part of CEI South's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, Mo., where it is used in the manufacture of cement.

Warrick Unit 4 burns Illinois basin bituminous coal. CEI South purchases coal for its share of Warrick Unit 4, which is mined in Knox County, Ind., and is delivered by rail.

6.2.2 Natural Gas

The A.B. Brown Generating Station currently has two natural gas fired Simple Cycle Gas Turbine ("SCGT") peaking units. Each has an installed capacity of 80 MW. ABB Unit 3 began commercial operation in 1991, while ABB Unit 4 became operational in 2002. Over the last three years Unit 3 has operated at a capacity factor of 3% with Unit 4 at 4%.

6.2.3 Renewables

The Blackfoot Clean Energy Facility located in Winslow, Ind., is a base load facility consisting of two Internal Combustion ("IC") landfill methane gas fired units. Blackfoot Units 1 & 2 became operational in 2009 and are capable of producing 1.5 MW each. Over the last three years these units have operated at a capacity factor of 38%.

The Oak Hill and Volkman Road universal solar projects in Evansville, Ind., became operational in 2018 with each location having an installed solar capacity of 2 MW. In addition to the solar capacity the Volkman Road site includes 1 MW of battery storage. These assets are located on the distribution system and are therefore netted out of CEI South's load for this analysis. Over the last three years these solar installations operated at an average annual capacity factor of 20%. The average annual capacity factor is affected by hours of daylight, cloud cover, temperature, etc.

The Troy solar facility located near Troy, Ind., began commercial operation in 2021. Single axis tracking panels were used for construction of the facility. Troy solar has an installed capacity of 50 MW and operated at a capacity factor of 24% in 2022.

6.2.4 Energy Efficiency

CEI South utilizes a portfolio of Demand Side Management ("DSM") programs to achieve demand reductions and energy savings, thereby providing reliable electric service to its customers. CEI South's DSM programs have been approved by the Commission and implemented pursuant to various IURC orders over the years.

Since 1992, CEI South has operated a Direct Load Control ("DLC") program called Summer Cycler which can reduce residential and small commercial air-conditioning and water heating electricity loads when needed during summer peak hours. A description of the program is included below. While this technology can still be reliably counted on to help lower demand for electricity at times of peak load, this aging technology will be phased out over time. CEI South's Summer Cycler program has served CEI South and its customers well for more than two decades, but more recent technology is now making the program obsolete. Between 2010 and 2021, CEI South's DSM programs reduced demand by approximately 82,000 kW and provided annual incremental gross energy savings of approximately 427,000,000 kWh.

The table below outlines the estimated program penetration on a yearly basis since CEI South programs began in 2010. Gross cumulative savings below, are shown as a percent of eligible retail sales. Note that historical DSM savings are implicitly included in the load forecast as these savings are embedded in the historical sales data.

Figure 6.5 Gross Cumulative Savings

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh)*	Gross Cumulative Savings (GW)[43]	Percent of Sales Achieved (Cumulative)
2010	5,617	2.53	0.00075	0.04%
2011	5,595	19.4	0.00549	0.35%
2012	5,465	66.95	0.01347	1.23%
2013	5,459	128.64	0.02669	2.36%
2014[44]	3,499	175.98	0.03277	5.03%
2015	3,224	202.82	0.03682	6.29%
2016	3,256	236.4	0.0451	7.26%
2017	3,281	268.86	0.05047	8.20%
2018	3,491	309.28	0.05775	8.86%
2019	3,135	352.76	0.06645	11.25%
2020	3,176	396.79	0.07437	12.49%
2021	3,174	427.19	0.08212	13.46%

[43] Gross Cumulative Savings are adjusted for Residential Behavioral, which has a one-year program life therefore not cumulative in nature.
[44] Statewide DSM programs ended in 2013. The drop in eligible sales is attributed to industrial customers opting out of DSM programs effective July 1, 2014.

6.2.4.1 2021-2023 Plan Overview

Consistent with the 2019 IRP, the framework for the 2021-2023 EE Plan was modeled at a savings level of 1.25% of retail sales adjusted for an opt-out rate of 77% of eligible load. Below is a listing of residential as well as commercial and industrial programs offered in 2021-2023. For full program descriptions including the customer class, end use of each program and participant incentives provided by the programs, please refer to the 2021-2023 EE Plan detail found in the Technical Appendix Attachment 6.1 CEI South Electric 2021-2023 DSM Plan.

Residential Programs

- Residential Specialty Lighting
- Income Qualified Weatherization
- Appliance Recycling
- Residential Prescriptive
    - Residential Midstream, Marketplace, Instant Rebates
- Residential New Construction
- Residential Behavior Savings
- Smart Cycle (“DLC Change Out”)
- Bring Your Own Thermostat (“BYOT”)
- Community Based – LED Specialty Bulb Distribution
- Conservation Voltage Reduction (“CVR”) Residential

Commercial and Industrial Programs

- Small Business Direct Install
- Commercial and Industrial Prescriptive
- Commercial and Industrial New Construction
- Commercial and Industrial Custom
- Building Tune-Up
- Multi-Family Retrofit
- Conservation Voltage Reduction - Commercial

The 2021-2023 plan was included as an existing resource in the 2019/2020 IRP and has an assumed average measure life of 12 years. The table below shows the amount of net savings included in the IRP as a resource (gross savings can be found in Technical Appendix Attachment 6.1 CEI South Electric 2021-2023 DSM Plan).

Figure 6.6 2021-2023 Energy Efficiency Savings

	2021[45]		2022[46]		2023[47]	
Sector	Net MWH Energy Savings	Net MW Demand Savings	Net MWH Energy Savings	Net MW Demand Savings	Net MWH Energy Savings	Net MW Demand Savings
Residential	13,640	3.1	10,810	2.8	13,404	3.2
C&I	16,279	4.3	12,432	2.2	25,169	3.7
Total	29,919	7.3	23,242	4.9	38,572	6.9

6.2.5 Demand Response

CEI South's tariff currently includes two active Demand Response ("DR") programs: 1) the Direct Load Control and 2) interruptible options for larger customers. Demand response programs allow CEI South to curtail load for reliability purposes. CEI South's tariff also includes a MISO DR tariff, in which no customers are currently enrolled. CEI South has engaged a DR aggregator who submitted a response to the All-Source RFP to explore DR potential based on customer load and industry demographics.

6.2.5.1 Current DLC (Summer Cycler)

The DLC program provides remote dispatch control for residential and small commercial air conditioning, electric water heating and pool pumps through radio-controlled load management receivers. Under the program, CEI South compensates customers in exchange for the right to initiate events to reduce air-conditioning and water-heating electric loads during summer peak hours. CEI South can initiate a load control event for

[45] 2021 Evaluation Results used for 2021
[46] 2022 Evaluation Results used for 2022
[47] 2023 Operating Plan used for 2023 Savings

several reasons, including to balance utility system supply and demand, to alleviate transmission or distribution constraints, or to respond to load curtailment requests from MISO.

CEI South manages the program internally and utilizes outside vendors for support services, including equipment installation and maintenance. Prospective goals for the program consist of maintaining load reduction capability and program participation while achieving high customer satisfaction. CEI South also utilizes an outside vendor, The Cadmus Group, to evaluate the DLC program and provide unbiased demand and energy savings estimates.

In 2023 Cadmus predicted that the DLC Program was capable of generating approximately 4 MWs of peak demand savings from residential air-conditioning load control and residential water heating load control during MISO load curtailment events. This is roughly half of prior predictions, which were used for IRP modeling.

Until recently, DLC switches have been the default choice for residential load control programs. CEI South has had a DLC program since the early 1990’s and as of 2022 had approximately 19,000 residential customers with 27,000 switches participating in the program. However, with the advent of smart thermostats and the myriad of benefits they offer for both EE and DR, CEI South has begun replacing DLC switches with smart thermostats.

6.2.5.2 Current Interruptible Load

CEI South makes available a credit for qualified commercial and industrial customers to curtail demand under certain conditions. CEI South previously had three customers who were participating for a total demand reduction of approximately 31 MW. MISO issued a curtailment on June 10, 2021. CEI South’s largest interruptible customer at approximately 30 MW elected to no longer participate in the interruptible tariff after the event. CEI South has no remaining customers on the tariff registered as a resource with MISO. New MISO testing requirements are in place to ensure DR resources are available throughout the year. MISO is proposing interruptible resource accreditation based on the amount of interruptions and available hours to curtail. MISO has already implemented mandatory annual testing that requires load interruptions to meet the test requirements. Prior to January 31, 2019, CEI South had never been requested by MISO to deploy LMRs, thereby interrupting customer load. While aggressive, CEI South maintained industrial interruptible load at the 25 MWs within the model throughout the analysis period, per stakeholder request and is exploring options to reach this level.

6.2.5.3 Smart Thermostats

CEI South launched its pilot Smart Wi-Fi Thermostat program in 2016, by installing 2,000 smart Wi-Fi enabled thermostats in homes in its service territory. As an alternative to DLC switches, smart thermostats can optimize heating and cooling of a home to reduce energy usage and control load while learning from occupant behavior/preference, adjusting Heating, Ventilation and Air Conditioning (“HVAC”) settings. Evaluation results are showing significantly more load reduction delivered by smart thermostats than DLC switches. As such, CEI South has designed a program to replace switches with smart Wi-Fi thermostats, a strategic option for cost-effective load control. The Smart DLC Change-out program focuses on residential single-family homes and apartment dwellers. By installing connected devices in customer homes rather than using one-way signal switches, CEI South will be able to provide its customer base deeper energy savings opportunities and shift future energy focus to customer engagement. This change-out program is reflected in IRP modeling.

Additionally, CEI South also launched the Bring your Own Thermostat (“BYOT”) program as a DR program. The BYOT program is a further expansion of the Residential Smart/Wi-Fi thermostat initiative. The 2021-2023 Plan provides for approximately 500kW demand each year from the BYOT program based on approximately 500 participants each year. BYOT allows customers who have or will purchase their own device from multiple potential vendors to participate in DR and other load curtailing programs managed through the utility. By taking advantage of two-way communicating smart/Wi-Fi thermostats, BYOT programs can help utilities reduce acquisition costs for load curtailment programs and improve customer satisfaction. BYOT allows the utility to avoid the costs of hardware, installation and maintenance associated with transitioning to a smart thermostat. Through the use of smart/Wi-Fi enabled thermostats, the utility can remotely verify how many customers are connected to the network at any given time and determine which thermostats are participating in DR events. Smart thermostat DR programs provide approximately 1 kW per thermostat in load reductions during a DR event.

6.3 POTENTIAL FUTURE OPTIONS MODELING ASSUMPTIONS

CEI South utilized the All-Source RFP for modeling inputs through 2027 for wind, solar, solar + storage resources. The following supply side information was based on a technology assessment from 1898 & Co. unless otherwise noted and was used to help provide needed information to model other resources where CEI South did not receive an RFP bid.

6.3.1 Supply Side

Resources are typically divided into supply side and demand side resources. Supply side simply means resources that produce energy.

6.3.1.1 Coal Technologies

Coal power plants, also known as Pulverized Coal ("PC") steam generators, are characterized by pulverizing coal, then burning the coal in a boiler to create heat. The heat from the boiler is then used to turn water into high pressure steam which is used to turn the turbine causing the generator to create electricity.

The power industry typically classifies conventional coal fired power plants as subcritical, supercritical and ultra-supercritical based on the steam operating pressure. Subcritical units operate below the critical point of water, which is 3208 psia and 705°F, supercritical units operate above the critical point of water. Ultra-supercritical units operate at even higher pressures or temperatures in order to increase efficiency. While efficiency is increased, higher grade and thicker materials must be used, which increase costs.

Proposed greenhouse gas ("GHG") regulations for new construction will limit CO_2 emissions to 1,100 lbs./MWh, a level which would require carbon capture on PC plants. Carbon capture on PC plants has been demonstrated in the field and as the technologies mature, they will likely become more technically and financially feasible, especially if markets emerge for the captured gases. See Figure 6-7 for further details on the coal technologies evaluated.

Figure 6-7 – Coal Technologies

Operating Characteristics and Estimated Costs	Supercritical Pulverized Coal with Carbon Capture	Ultra-Supercritical Pulverized Coal with Carbon Capture
Base Load Net Output (MW)	506	747
Base Load Net Heat Rate (HHV Btu/kWh)	11,290	10,480
Base Project Costs (2022$/kW)	$6,660	$6,020
Fixed O&M Costs (2022$/kW-year)	$32.01	$32.01

6.3.1.2 Natural Gas Technologies

Natural gas power plants are characterized by igniting natural gas and transforming the heat generated from combustion into electrical energy. Various forms of natural gas generation were evaluated in this IRP. Multiple existing and planned generation facilities were considered for conversion options. AB Brown 5 and 6 are approved to be built and operate as simple cycle combustion turbines, the conversion of these units to a 2x1 combined cycle was considered in the model. The addition of a heat recovery steam generator to capture waste heat results in a very efficient unit that would dispatch and run most of the time. In contrast, the conversion of F.B Culley 3 from firing on coal to natural gas, with firm supply, provides peaking generation and will not run much. It was considered at different points throughout the study period. Figure 6-8 and Figure 6-9 outline the details of these conversion options. Cogeneration was also evaluated through this IRP process. Cogeneration, also known as combined heat and power, is the process of using waste heat to boil water and pump steam from the boiler into a generator. Electrical generation and heating water are produced from this process. See Figure 6-10 for details

Figure 6-8 – Combustion Turbine to Combined Cycle Conversion

Operating Characteristics and Estimated Costs	SCGT to 2x1 F Class CCGT Conversion
Base Load Net Output (MW)	717 / 257 incremental
Base Load Net Heat Rate (HHV Btu/kWh)	6,480
Base Project Costs (2022$/kW)	$774
Fixed O&M Costs (2022$/kW-year)	$5.86

Figure 6-9 – F.B. Culley 3 Natural Gas Conversion

Operating Characteristics and Estimated Costs	F. B. Culley 3 Gas Conversion
Base Load Net Output (MW)	270 / 0 incremental
Base Load Net Heat Rate (HHV Btu/kWh)	10,544
Base Project Costs (2022$/kW)[48]	$196
Fixed O&M Costs ($/kW-year)[49]	$39.16

Figure 6-10 – Cogeneration Technologies

Operating Characteristics and Estimated Costs	Cogeneration
Base Load Net Output (MW)	22
Base Project Costs (2022$/kW)	$2,832
Fixed O&M Costs (2022$/kW-year)	$323

6.3.1.2.1 Simple Cycle Gas Turbines (Combustion Turbines or CT)

SCGT utilize natural gas to produce power. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Typically, SCGTs are used for peaking power due to fast load ramp rates, higher heat rates compared to other technologies and relatively low capital costs. See Figure 6-11 for further details on the simple cycle gas turbine technologies evaluated.

[48] Base project costs were evaluated in the earliest conversion year and discounted to 2022
[49] Fixed O&M costs were evaluated in the year following the conversion of the power plant

To aid in the evaluation of SCGT, technology estimates were developed to represent the natural gas pipeline costs to supply firm gas service to the unit. Estimates were developed for firm gas supply (as opposed to interruptible) because of recent changes to MISO's resource adequacy construct; they have signaled that while summer peak hours are important, all hours of the year matter and a dispatchable resource needs to be available for service when needed by the system. CEI South had two recent data points for what firm gas pipeline service could cost that were used to approximate what gas supply for various non-site specific gas resources could be based on their peak gas demand.

Figure 6-11 – Simple Cycle Gas Turbine Technologies

Operating Characteristics and Estimated Costs	1xF-Class SCGT	1xG/H-Class SCGT	1xJ-Class SCGT
Base Load Net Output (MW)	229	287	372
Base Load Net Heat Rate (HHV Btu/kWh)	10,010	9,260	9,240
Base Project Costs (2022$/kW)	$940	$910	$740
Fixed O&M Costs (2022$/kW-year)[50]	$8.30	$6.63	$5.11

6.3.1.2.2 Combined Cycle Gas Turbines

Combined Cycle Gas Turbines ("CCGT") utilize natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator and to also use the hot exhaust gases from the gas turbine to produce steam in a Heat Recovery Steam Generator ("HRSG"). This steam is then used to drive the steam turbine and generator to produce electric power. Using both gas and steam turbine (Brayton and Rankine) cycles in a single plant results in high conversion efficiencies and low emissions. Additionally, natural gas can be fired in the HRSG to produce additional steam and associated output for peaking load, a process commonly referred to as duct firing.

For this assessment, a 1x1 F class (unfired and fired), 1x1 G/H class (unfired and fired), 1x1 J class (unfired), and 2x1 J class as shown in Figures 6-12 and 6-13, were evaluated with General Electric ("GE") turbines as representative CCGT technologies. The F class

[50] The cost for firm gas supply was included in this analysis but isn't included in the Fixed O&M Costs in this table

is based on the GE 7F.05 turbine and the G/H class is based on the GE HA.01 turbine. A 1x1 CCGT is configured with one gas turbine and one steam turbine where a 2x1 CCGT is configured with two gas turbines and one steam turbine.

Figure 6-12 – Combined Cycle Gas Turbine Technologies

Combined Cycle Gas Turbines - Fired			
Operating Characteristics and Estimated Costs[51]	**1x1 F-Class**	**1x1 G/H-Class**	**2x1 J-Class**
Base Load (24/7 Power) Net Output (MW)	360	427	1,101
Incremental Duct-Fired (Peaking) Net Output (MW)	58	80	205
Base Load Net Heat Rate (HHV Btu/kWh)	6,590	6,240	6,280
Incremental Duct-Fired Heat Rate (HHV Btu/kWh)	8,730	8,720	8,690
Base Project Costs (2022$/Fired kW)	$1,300	$1,180	$770
Fixed O&M Costs (2022$/Base Load kW-year)[52]	$10.75	$8.85	$3.98

Figure 6-13 – Combined Cycle Gas Turbine Technologies

Combined Cycle Gas Turbines - Unfired			
Operating Characteristics and Estimated Costs[53]	**1x1 F-Class**	**1x1 G/H-Class**	**1x1 J-Class**
Base Load (24/7 Power) Net Output (MW)	363	431	551
Base Load Net Heat Rate (HHV Btu/kWh)	6,540	6,200	6,270
Base Project Costs (2022$/Fired kW)	$1,450	$1,320	$1,100
Fixed O&M Costs (2022$/Base Load kW-year)	$12.39	$10.45	$8.16

6.3.1.3 Renewables Technologies

Three renewable technologies were evaluated in the IRP. Those technologies were wind energy, solar photovoltaic, and hydroelectric. Wind and solar resources were modeled to include production tax credits, while hydroelectric resources and storage included discounts for the investment tax credit. Under the IRA solar resources now have the option to choose between the investment tax credit and the production tax credit. Based

[51] Combined cycle gas turbines are shown as fired configuration for this table.
Reference the Technology Assessment for additional details on duct-firing
Operational and cost estimates developed by Black & Veatch
[52] The cost for firm gas supply was included in this analysis but isn't included in the Fixed O&M Costs in this table
[53] Combined cycle gas turbines are shown as unfired configuration for this table.

on the assumed capacity factor of solar resources, the production tax credits are anticipated to provide more value and therefore were used in the model.

6.3.1.3.1 Wind

Wind turbines convert the kinetic energy of wind into mechanical energy. Typically, wind turbines are used to pump water or generate electrical energy which is supplied to the grid. See Figure 6-14 for further details on wind technologies evaluated. Beyond the RFP bids, the following assumptions were based on the 1898 & Co. tech assessment.

Figure 6-14 – Wind Technologies

Operating Characteristics and Estimated Costs	Wind (Southern Indiana)	Wind (Northern Indiana)	50 MW Wind (Indiana) & 10 MW / 40 MWh Storage
Base Load Net Output (MW)	200	200	50
Base Project Costs (2022$/kW) / ($/kWh for Storage)	$1,840	$1,840	$2,110
Fixed O&M Costs (2022$/kW-year)[54]	$48.00	$48.00	$49.00
Annual Capacity Factor	28%	38%	

6.3.1.3.2 Solar

The conversion of solar radiation to useful energy, in the form of electricity, is a mature concept with extensive commercial experience that is continually developing into a diverse mix of technological designs. Solar conversion technology is generally grouped into solar PV technology, which directly converts sunlight to electricity due to the electrical properties of the materials comprising the cell.

PV cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively and negatively charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an

[54] Variable O&M costs are included in the Fixed O&M estimate in this table.

aluminum back-plate on the other. See Figure 6-15 for further details on the solar PV technologies evaluated.

Figure 6-15 – Solar Technologies

Operating Characteristics and Estimated Costs	10 MW Solar PV	50 MW Solar PV	100 MW Solar PV	50 MW Solar PV & 10 MW / 40 MWh Storage
Base Load Net Output (MW)	10	50	100	50
Base Project Costs (2022$/kW)	$2,560	$1,860	$1,780	$1,910
Fixed O&M Costs (2022$/kW-year)[55]	$60.00	$16.00	$11.00	$22.34

6.3.1.3.3 Hydroelectric

Low-head hydroelectric power generation facilities are designed to produce electricity by utilizing water resources with low pressure differences, typically less than 5 feet head but up to 130 feet. This allows the technology to be implemented with a smaller impact to wildlife and environmental surroundings than conventional hydropower. However, power supply is dependent on water supply flow and quality, which are sensitive to adverse environmental conditions like dense vegetation or algae growth, sediment levels and drought. Additionally, low-head hydropower is relatively new and undeveloped, thus resulting in a high capital cost for the relatively small generation output. See Figure 6-16 for further details on the hydroelectric technology evaluated.

Data from a U.S. Army Corps of Engineers report was used to determine the economically feasible output from the Newburgh and John T. Myers dams located locally on the Ohio River. This report showed when taking economics into consideration both dams had an average potential output near 50 MW which was consistent with tech assessment data used in the analysis. A separate publication from the U.S Army Corps of Engineers showed the estimated construction cost of the Cannelton facility was very close to the assumptions used in the analysis.

[55] Variable O&M costs are included in the Fixed O&M estimate.

Figure 6-16 – Hydroelectric

Operating Characteristics and Estimated Costs	John T. Myers	Newburgh
Base Load Net Output (MW)	36	22
Base Project Costs (2022$/kW)	$6,478	$6,478.29
Fixed O&M Costs (2022$/kW-year)	$98.90	$98.90

6.3.1.3.4 Congestion Charges

Transmission congestion charges are the final element for consideration when analyzing the true cost of delivered resources and are the most difficult to estimate. Congestion charges are calculated by taking the difference in Locational Marginal Price ("LMP") where the energy is injected (source) and where the energy is withdrawn (sink). For CEI South to purchase energy outside of Zone 6 (Indiana) or even off CEI South's system in Indiana, CEI South would be responsible to pay the LMP at the sink and would receive payment from the source. Therefore, any price differential is an added risk and possible added cost to the delivery of energy. MISO does not provide estimates of congestion charges due to the volatility and immense variability that impacts the MISO transmission system and the congestion related charges. When taking into consideration the cost of a resource, the required transmission charges and estimated congestion charges based on historical data, the greater the distance, the greater the potential for higher costs.

CEI South's modeling did not account for congestion. When selecting future resources following the resource plan, congestion and differences in LMP will be important factors to consider.

6.3.1.4 Energy Storage

Two types of energy storage technologies were evaluated in the IRP, lithium-ion batteries (typically short-duration) and compressed air storage (long-duration). These are shown in Figure 6-17.

Lithium-ion technology represents a significant majority of utility scale, stationary energy storage projects being developed and installed in the current market. It is the most commercially and technically mature battery storage solution in today's market and is commonly the most cost-effective option for grid-scale applications/use cases with a 1-4 hour discharge duration at rated power. However, the energy storage market is rapidly evolving. Long duration is not a defined term, but it is generally assumed that >4-hour discharge duration. Several non-lithium technologies may become competitive for long duration energy storage ("LDES") in the future. While it is technically achievable for multiple 4-hour lithium-ion battery systems to be controlled to behave similarly to a longer duration technology, the unit cost ($/kWh) for lithium-ion remains relatively flat for longer duration applications. In other words, there is not much economies of scale for longer duration applications. For this IRP we modeled 4-hour lithium-ion batteries but did not limit the number of resources selected, therefore, multiple 4-hour could be selected if a need for longer durations was identified by the model.

There are numerous technologies of varying commercial and technical maturity, and while CEI South recognizes the desire for technology diversity, a single representative technology was selected to represent the broader category of LDES. Compressed Air Energy Storage ("CAES") is a maturing technology that is suitable for large, utility scale projects. While CAES will be limited in implementation depending on certain geologic characteristics, it generally represents the lower end of today's LDES capital cost range and is therefore a representative technology for resource planning. CEI South is aware of other technologies/chemistries that are being marketed for durations >24 hours with cost targets that are lower than CAES and other LDES options, but CAES is generally considered as a more commercially and technically mature technology for this planning cycle. One technology that was not included in modeling but was considered by CEI South and mentioned by stakeholders was an iron-air battery by Form Energy. This was ultimately not modeled in this IRP because of the lack of commercial viability and lack of available modeling data at this time. CEI South will continue to evaluate emerging technologies and may include other technology(ies) in future resource planning cycles.

Figure 6-17 – Energy Storage Technologies

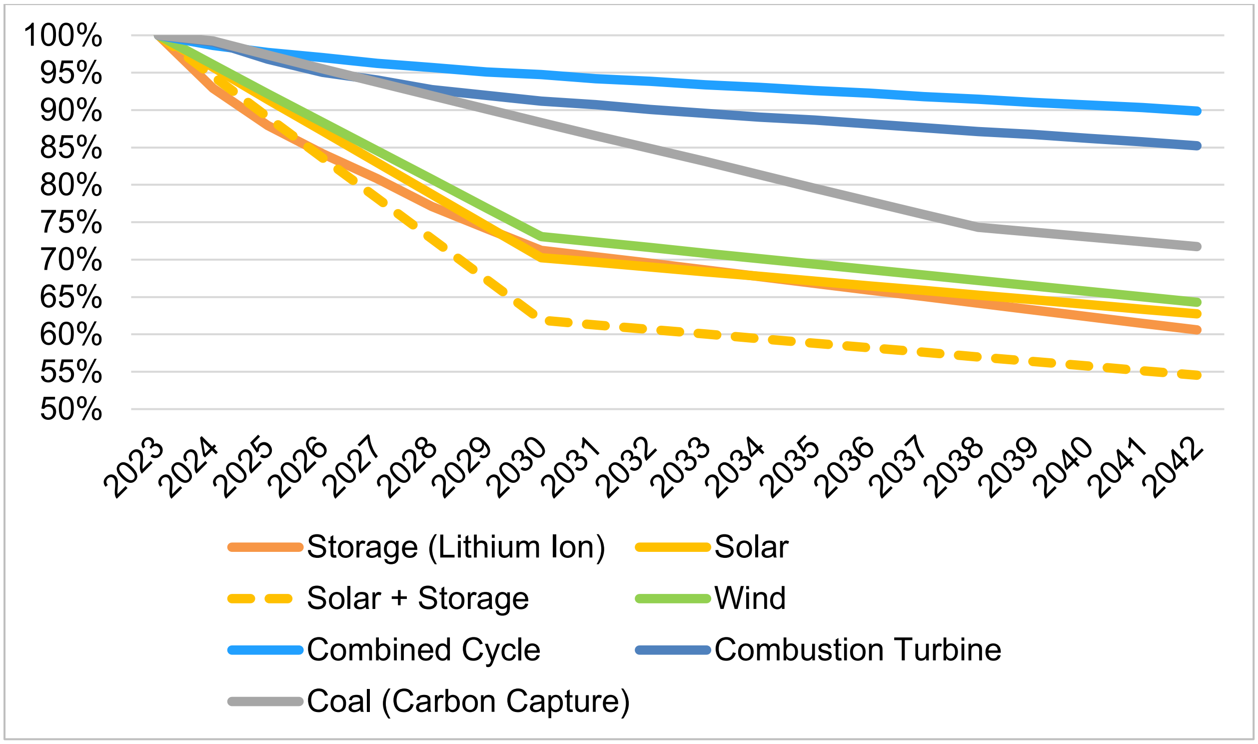
Operating Characteristics and Estimated Costs	Lithium Ion 10 MW / 40 MWh	Lithium Ion 50 MW / 200 MWh	Long-Duration Proxy 100 MW / 400 MWh	Long-Duration Proxy 300 MW / 3,000 MWh
Base Load Net Output (MW)	10	50	100	300
Round-Trip Cycle Efficiency	85%	85%	85%	60%
Base Project Costs (2022$/kW)	$2,500	$2,160	$2,020	$2,590
Fixed O&M Costs (2022$/kW-year)	$40.00	$38.00	$35.00	$19.33
Variable O&M Costs (2022$/MWh)	Included in FOM	Included in FOM	Included in FOM	$2.60

6.3.1.5 Cost Curve Discussion

Forward looking capital cost forecasts were developed and used as part of the 2022/2023 IRP process. Capital cost curves vary based on the generation technology, as shown in Figure 6-18.

Technologies whose capital costs do not decline significantly over the IRP time period such as wind, natural gas, coal and hydro are generally more mature, while technologies such as solar and storage are less mature and are expected to experience larger reductions in capital cost over the IRP time period. In the next 20 years, new technological developments and increasing efficiencies in solar and storage are expected to decrease capital costs over time. Due to uncertainty associated with these less mature technologies, CEI South relied upon information collected as part of the RFP as well as NREL cost curves to help project capital costs over the study period. Figures 6-18 shows modeled values in the Reference case Scenario.

Figure 6-18 – Forward Capital Cost Estimates[56]



6.3.2 DSM

6.3.2.1 Energy Efficiency Background

In developing a resource plan that integrates demand side and supply side resources, it is incumbent for the energy company to provide the integrating process with a set of DSM options that can be incorporated into the plan. This process aligns with IURC's Rule 170 IAC 4-7-6(b) which states:

> "An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers."

[56] Percent decline based on real 2022 dollars.

In addition, this process aligns with Senate Enrolled Act ("SEA") 412 which requires energy efficiency goals be consistent with an electricity supplier's IRP. Taken together, these jointly supportive requirements direct the energy company to study, similar to supply side resources, available DSM options that may be chosen by the IRP analytical process in arriving at a resource plan. In other words, the level of DSM to be pursued by the energy company should be determined through the IRP process.

6.3.2.2 DSM Market Potential Study

The first step in the process is a Market Potential Study ("MPS"). A key purpose of an energy efficiency MPS is to provide energy efficiency planners, decision makers and interested stakeholders with a roadmap to the best opportunities for energy efficiency savings opportunities in the residential, commercial and industrial customer classes. "Energy efficiency potential studies are an effective tool for building the policy case for energy efficiency, evaluating efficiency as an alternative to supply side resources and formulating detailed program design plans. They are typically the first step taken by entities interested in initiating or expanding a portfolio of efficiency programs and serve as the analytic basis for efforts to treat energy efficiency as a high-priority resource equivalent with supply-side options."[57] The results of a potential study pinpoint the energy efficiency measures having the greatest potential for energy savings and identifies the measures that are the most cost effective. Program administrators, regulators and stakeholders can use the results of potential studies to determine the types of programs that should be implemented and how much to invest in energy efficiency as a resource. Potential studies also provide useful information on the benefits and costs of energy efficiency measures and programs from various viewpoints: societally, all ratepayers, the program administrator, program participants and utility rates.

[57] "Guide for Conducting Energy Efficiency Potential Studies"; Prepared by Philip Mosenthal and Jeffrey Loiter, Optimal Energy, Inc.; https://www.epa.gov/sites/production/files/2015-08/documents/potential_guide_0.pdf ; November 2017; page ES-1

CEI South's MPS completed in 2022 was both to inform the IRP and support the development of a DSM Action Plan for CEI South. The study included a comprehensive review of current programs, historical savings and projected energy savings opportunities to develop estimates of technical, economic and achievable potential. The study leveraged existing primary market research from the 2019 MPS for the C&I sector in the CEI South service area for the saturation of energy-using equipment, building characteristics and the percent of energy using equipment that is already high efficiency. Existing primary market research from the 2019 study was also leveraged to estimate customer willingness to participate in energy efficiency programs at different incentives levels and targeted end-uses.

Technical potential is the maximum energy efficiency available, assuming cost and market adoption of a technology are not a barrier. Economic potential is the subset of technical potential that is cost effective, meaning the economic benefit outweighs the cost. The economic potential is measured by the total resource cost test, which compares the lifetime energy and capacity benefits to the incremental cost of the energy efficiency measure. While some may contend the full technical or economic potential should be provided as the level of DSM options available in the IRP process, this ignores the fact that 100% of the customers would have to participate. This is not realistic as historical evidence has shown not all customers will adopt a given technology for reasons that range from aesthetic preferences, lack of information about energy efficiency measures, lack of access to capital to perceived comfort concerns. Rather, the potential modeled in the IRP should reflect some consideration of achievability.

To that end, 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. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

Maximum Achievable Potential estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.

Realistic Achievable Potential estimates achievable potential with CEI South 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.

It is important to also note the estimates of potential considered in the MPS (and ultimately, in the IRP) exclude potential savings from customers who are eligible and have chosen to actively opt-out of participating in CEI South’s energy efficiency programs. In the CEI South service area, approximately 11% of commercial energy sales and 72% of industrial energy sales are associated with customers who have elected to opt-out.

In addition to the energy efficiency potential study, a demand response potential study was also conducted. The methodological approach to the demand response potential study closely mirrored the energy efficiency analysis, with an assessment of the calculation of the demand response technical, economic, and achievable potential. The demand response study analyzed existing programs, such as the Smart Cycle and BYOT programs, as well as potential new programs, such as Critical Peak Pricing rates. The demand response study shows the amount of potential demand that could be realized if customers shift their electric usage from on-peak to off-peak periods.

6.3.2.3 Energy Efficiency – IRP Reference Case

Energy Efficiency for the 2023 and 2024 IRP years were informed directly from CEI South DSM Settlement Agreement (2023) and anticipated one-year plan extension (2024).

These years of energy efficiency were treated as a “going-in” resource in the IRP. For the remaining IRP years (2025-2042), CEI South used the realistic achievable potential identified in the MPS as the starting point for energy efficiency to be modeled in the IRP. CEI South worked closely with GDS and its stakeholders to formulate an approach to bundling DSM that addressed stakeholder requests, met the IURC rules and fit the EnCompass IRP model requirements. The GDS Team initially provided the energy efficiency IRP inputs across three sector categories (residential, income-qualified, and commercial/industrial). The residential and commercial/industrial bundles were modeled as selectable resources in the EnCompass model. Like 2023/2024 EE levels, the 2025-2042 income-qualified bundle was also treated as a ‘going-in’ resource as the high costs of program delivery would likely prevent its selection in the IRP, and CEI South anticipates continuing to offer energy efficiency program offerings to their income-qualified customers despite these limitations in cost-effectiveness.

In addition to the sector segmentation, the annual bundles were grouped into three separate time series. The three different vintage bundles: 2025-2027, 2028-2030, and 2031-2042 allow the model to optimize the value of energy efficiency over different time periods. The first two periods were designed to align with the next CEI South DSM program planning periods, followed by a larger third time series that could provide guidance on DSM selections for the remaining IRP timeframe.

In the process of developing the initial sector-level bundles, two savings adjustments and one cost adjustment were necessary prior to inclusion in the IRP. The first adjustment converted the energy efficiency achievable potential from gross savings to net savings. It is appropriate to model net energy efficiency impacts to remove MWh and MW impacts that would have occurred in the absence of CEI South’s programs. Net savings were calculated by applying CEI South’s most current NTG ratios to the MPS estimates of gross achievable savings.

The second savings adjustment was to provide the program potential savings at the generator level. The MPS savings are reported at the meter-level. Sector savings were adjusted based on average system line loss rate of 6% to convert savings from the meter level up to the generator level. Figure 6-19 provides a comparison of the total residential, commercial/industrial, and income-qualified sector incremental annual savings from the MPS versus the IRP based on these two adjustments. On the cost side, because the IRP's Capacity Expansion Model does not calculate avoided transmission and distribution (T&D) benefit associated with DSM measures, the GDS Team provided CEI South with energy efficiency costs that have been adjusted to net out the avoided T&D benefit.

6.3.2.4 Demand Response ("DR")

Five bundles for DR savings were included for selection in the IRP Reference Case. The first bundle was included as a fixed adjustment to the total system load, similar to a "must-run" generation unit. This bundle includes DR savings associated with CEI South's current DR capabilities including the historical number of direct load control switches on residential air conditioning units in the CEI South service area. Over the IRP time frame, CEI South anticipates replacing existing direct load control switches with smart thermostats that integrate DR capabilities (via the Smart Cycle Program). The estimated annual impacts for the fixed bundle of DR are approximately 6.8 MW in 2025, increasing to 9 MW by 2042.

A second bundle, consisting of additional residential DR-enabled smart thermostats ("BYOT Thermostats") above and beyond the current penetration of DR devices, was included as a selectable resource. This bundle represents an additional 7.6 MW of peak reduction capabilities in 2025 increasing to 33 MW by 2042.

A third bundle consists of residential rate options, including critical peak pricing, peak time rebates, and time of use rates. This bundle is assumed to not start until 2026 and builds slowly as a pilot program through 2030. In 2026, this bundle represents 0.3 MW in 2026 and increases to 18.5 MW in 2042.

A fourth bundle consists of additional C&I DR BYOT Thermostats above and beyond the current penetration of DR devices, which was included as a selectable resource. This bundle represents an additional 1.1 MW of peak reduction capabilities in 2025 and increases to 4.9 MW in 2042.

The fifth bundle consists of a critical peak pricing rate option for non-residential customers. This bundle is assumed to not start until 2026 and builds slowly as a pilot program through 2030. In 2026, this bundle represents 0.1 MW in 2026 and increases to 5.9 MW in 2042.

6.3.2.5 DSM Resources Optimization Process

The previous sections provided the Reference Case projection of DSM resource costs. DSM resource costs are a key component to the integration of DSM into the resource plan. Given the uncertainty around these costs, especially considering a 20-year implementation period, alternate views of the costs should be examined in the context of the scenario analyses. Only time and actual experience with increases in DSM market penetration will provide better guidance on these cost projections. To that end CEI South made specific targeted adjustments to identify the amount of EE selected at various cost and savings tiers as described below.

Figure 6-19 – MPS Versus Initial IRP Bundles Comparison – Sum of Incremental MWh

	Vintage 1: MPS	Vintage 1: IRP	Vintage 2: MPS	Vintage 2: IRP	Vintage 3: MPS	Vintage 3: IRP
Residential	44,452	43,316	51,714	49,569	277,358	263,215
C&I	69,839	64,560	81,164	75,993	340,197	324,440
IQW	1,276	1,353	1,460	1,547	7,883	8,356

Following an early review of the residential and commercial/industrial energy efficiency savings and costs inputs, the GDS Team further segmented the residential sector savings into high-cost measures (Tier 2), and low/mid cost measure (Tier 1) across each vintage time-series due to concerns that an aggregate residential sector bundle would not get selected. In addition, residential behavioral energy efficiency savings were also segmented into a third residential sector bundle due to its distinct 1-year measure life. Figure 6-20 summarizes the levelized cost per lifetime kWh saved of each initial bundle by vintage.

Figure 6-20 – Levelized Utility Cost per Lifetime MWh Saved Based on Initial Bundles

	Res Tier 1	Res Tier 2	Res Behavior	IQW	C&I
V1: 2025-2027	$50.99 - $51.95	$126.36 - $128.50	$35.18 - $37.35	$195.40 - $200.32	$21.07-$21.86
V2: 2028-2030	$52.51 - $53.52	$129.75 - $132.09	$38.51 - $41.01	$201.98 - $204.57	$22.70-$24.24
V3: 2031-2042	$52.41 - $65.64	$133.04 - $141.75	$42.37 - $60.12	$206.39 - $223.49	$25.22-$32.89

As part of an iterative review process, two further modifications to the sector level EE bundles were ultimately made. The first adjustment, which increased the overall savings and costs for commercial/industrial energy efficiency, were made at the request of members of the CEI South Oversight Board ("OSB")[58]. The GDS Team created an additional "Enhanced" Achievable Potential Scenario that increased incentives for select lower-cost commercial/industrial measures, resulting in increased estimates of measure adoption. This adjustment was requested due to the overall favorable levelized cost per lifetime kWh saved associated with the commercial/industrial sector, and the idea that additional savings could be realized without risking selection in the IRP model. In total C&I savings increased by 7.8% from 2025-2027, 4.5% from 2028-2030, and 1.5% from 2031-2042.

Conversely, based on a preliminary IRP model run, neither the Tier 2 nor Tier 1 residential sector bundles were selected in the IRP. To allow the IRP model to select residential energy efficiency, the residential sector bundles were redrawn, shifting higher cost measures in the original Tier 1 bundle into the Tier 2 bundle. This iterative re-screening of the Tier 1 and Tier 2 residential bundles in the IRP model ensured that a significant

[58] Citizens Action Coalition, Office of Utility Consumer Counselor, CEI South

component of the residential sector achievable potential would get economically selected in the IRP.

Figure 6-21 – Comparison of Preliminary and Final Tier 1 Savings and Costs

	Preliminary Vintage 1	Final Vintage 1	Preliminary Vintage 2	Final Vintage 2	Preliminary Vintage 3	Final Vintage 3
MWh	16,004	14,139	19,542	16,759	120,948	99,828
Costs	$6,898,272	$5,750,337	$8,372,620	$6,587,076	$52,278,442	$36,943,528

The final bundle incremental savings for energy efficiency and associated levelized utility cost per lifetime savings are provided in Figure 6-22 below. In addition to the annual impacts shown in these tables, hourly (or 8,760) shapes that reflect the various measures and end-use mix reflected in each EE resource bundle were provided to CEI South to permit the IRP model to assess the value of energy savings on an hourly basis. These 8,760 shapes were based on residential and commercial end-use load shapes for Indiana from NREL End-Use Load Profiles database. The ultimate 8,760 shapes are unique for each EE sector and vintage bundle.

Figure 6-22 – Annual MWh EE Savings and Levelized Costs per Lifetime kWh Saved by Bundle

	Enhanced C&I		Res Tier 1		Res Tier 2		Res Behavior		IQW	
	MWh	$/LT-MWh	MWh	$/LT-MWh	MWh	$/LT-MWh	MWh	$/LT-MWh	MWh	$/LT-MWh
2025	21,523	$26.07	3,884	$48.54	1,592	$110.66	7,608	$35.18	442	$195.40
2026	23,569	$25.89	5,024	$48.63	2,286	$112.59	7,558	$36.24	439	$199.53
2027	24,508	$25.98	5,230	$48.93	2,629	$113.96	7,505	$37.35	471	$200.32
2028	25,885	$26.46	5,416	$49.24	3,003	$115.47	7,450	$38.51	492	$201.98
2029	26,035	$26.84	5,570	$49.31	3,448	$116.95	7,391	$39.72	523	$203.12
2030	27,470	$27.40	5,773	$49.21	4,191	$118.40	7,328	$41.01	533	$204.57
2031	28,769	$28.05	6,135	$49.38	4,867	$119.39	7,260	$42.37	549	$206.39
2032	29,196	$28.50	6,292	$49.46	5,515	$120.07	7,190	$43.80	560	$208.68
2033	29,006	$29.00	6,618	$49.68	6,060	$120.56	7,119	$45.28	578	$210.99
2034	29,105	$29.69	6,852	$49.95	6,447	$120.81	7,048	$46.81	595	$213.42
2035	29,115	$31.01	8,489	$51.69	7,064	$122.07	6,975	$48.42	629	$213.42
2036	27,731	$31.89	8,775	$52.51	7,226	$122.64	6,907	$50.05	659	$214.88
2037	26,828	$33.44	8,945	$53.41	7,112	$122.81	6,840	$51.73	696	$217.46
2038	25,458	$34.31	8,978	$54.44	7,006	$122.58	6,781	$53.41	733	$20.28
2039	23,775	$35.14	8,666	$55.31	6,794	$122.83	6,729	$55.08	777	$223.49
2040	27,805	$34.19	10,331	$57.74	7,502	$125.20	6,682	$56.77	819	$219.17
2041	26,718	$34.52	10,076	$58.47	7,543	$126.17	6,642	$58.45	862	$218.27
2042	25,916	$34.89	9,672	$59.26	7,468	$127.16	6,608	$60.12	899	$219.10

No IRP sensitivities for the low-income savings or DR savings were included in the IRP as these bundles were modeled as fixed load impacts.

6.3.2.6 DSM Improvements Based on Stakeholder Feedback

Review of prior comments from stakeholders and robust stakeholder discussion led to several improvements to DSM modeling since the 2019 IRP. The model has been allowed to make multiple decisions over the 20-year period. The model selects DSM for two three-year periods beginning in 2025 and 2028 and then evaluates the remaining years beginning in 2031 as one collective group. This allows the model to select the appropriate level of DSM based on cost-effectiveness differences and resource needs across the short, mid and long run. The characterization of the bundles included in the IRP modeling was based on a collaborative process with the stakeholders. This led to originally separating bundles between the residential and non-residential sectors (aligning with recommendations from the prior IRP Directors Report), further breaking down the residential sector into the four bundles (including Income-Qualified) noted above, and finally increasing the C&I bundle savings and re-mapping the residential measure bundles to ensure cost-effective energy efficiency savings were selected across all sectors. Additional sector and end-use specific hourly load shapes were included to more accurately estimate the timing of the energy efficiency impacts throughout the year. Also, expanded DR bundles were included in the model.

6.3.2.7 Other Innovative Rate Design

CEI South periodically evaluates alternative rate design and its ability to implement new options as the energy marketplace continues to evolve. Proposals that provide variable energy pricing based on how electric prices change throughout the day (Time of Use rates) and other pricing alternatives are being considered now that the required technology upgrades are being finalized, including technology to improve access to multitudes of data provided by installation of AMI.

CEI South formed a team of people to explore opportunities to provide customers with TOU rates. CEI South has hired Cadmus to help in researching and developing a pilot for a Critical Peak Pricing ("CPP") program. CEI South plans to bring the proposal to the

Commission as part of its upcoming rate case and utilize results to help shape future resource planning.

6.4 TRANSMISSION CONSIDERATIONS

6.4.1 Description of Existing Transmission System

CEI South's transmission system is comprised of 64 miles of 345 kV lines, 430 miles of 138 kV lines and 570 miles of 69 kV lines. It has interconnections with Duke Energy (345 kV-138 kV-69 kV), Hoosier Energy (161 kV-69 kV), Indianapolis Power and Light Co. (138 kV), Big Rivers Electric Company (345kV-138 kV) and LGE/KU (138 kV). Key interconnection points include three 345 kV interconnections to Duke Energy's system in the area of Duke's Gibson Generation Station and Duff Substation, a 345kV interconnection to Big Rivers' Coleman Substation, a 345 kV interconnection to Big Rivers' Reid EHV Substation, a 138 kV interconnection at AES/IPL's Petersburg Generation Station and 161 kV and 138 kV interconnections to Hoosier Energy, LGE/KU and Big Rivers at CEI South's Newtonville Substation.

6.4.2 Discussion on Resources Outside of Area

As mentioned above, CEI South's transmission system interconnects with neighboring systems, which provides wholesale import and export capability. Transmission planning studies indicate the existing transmission system provides a maximum import capability of approximately 645 MWs in peak demand periods and approximately 750 MWs in off-peak demand periods (or approximately 35-40% of peak demand). Although CEI South has the capability to offset internal generation with imported capacity, this is not a long-term solution; several factors would influence that capability, including:

- MISO resource adequacy requirements
- Availability of firm capacity
- Transmission path availability
- Operating concerns (post-contingent voltage and line flow)
- Anticipated congestion costs

- Real-time binding constraints

6.4.3 Transmission Facilities as a Resource

As part of this year's IRP, CEI South performed a multitude of transmission planning analyses to study a wide range of potential futures. These included studying the additional retirement of coal generation and partial replacement of these retirements with Battery Energy Storage Solutions ("BESS"), Conversion of FB Culley to natural gas, and import from the MISO market. Each of these cases also included the addition of various levels of renewable resources, primarily solar. The models utilized were from the latest 2022 MISO Transmission Expansion Plan ("MTEP") model series, which includes future transmission system projects and approved generation interconnections. The primary focus of the analysis was on the peak and off-peak (Shoulder) 5-year planning horizon. Modeling parameters for the new renewable resource additions were utilized from the latest cycle of the MISO generation interconnection process. These generation projects included known generation replacement projects and those projects in final negotiations to execute generation interconnection agreements with MISO. These projects were included in order to have the latest modeling data for generation resources in CEI South's area. The renewable resources used for CEI South's analysis were projects already in the MISO queue and existing in the MISO models. The analysis did account for the new CTs at CEI South's A.B. Brown power plant.

The convert F.B. Culley 3 to natural gas case was modeled at a similar MW output as the coal generation it was replacing and therefore the results of the transmission planning study analysis showed very few differences from the study case with the system as it is today, or Base Case. Therefore, no costs were identified in this case to mitigate potential issues on the system.

The analysis found the need for facility upgrades and voltage support under scenarios with retirement of FB Culley Unit 3 and integration of renewable resources. The total estimated costs of system reinforcements identified ranged from $17.6 million to $328 million depending on the scenario evaluated. The scenario where Culley Unit 3 is retired included mitigation costs of $17.6 million under the peak demand period. The F.B. Culley replacement with BESS had mitigation costs between approximately $154 million and $328 million. The magnitude of system reinforcements was the most significant during the off-peak demand period, as opposed to the peak demand period, driven by heavy imports, no solar production, and BESS charging conditions. Major upgrades on the high-end include rebuilding several transmission lines on the 138 kV system, two (2) additional 345/138 kV transformers at A.B. Brown, an upgrade of the A.B. Brown to Gibson 345 kV line, and an additional 560 MVar of reactive support. The system reinforcements would reduce further as the size of the BESS is reduced.

The system reinforcement needs under the peak demand period for the heavy import scenario were estimated to be between $17.5 million and $55 million. The magnitude of system reinforcements was found to be more in a heavy import scenario. Major upgrades on the high-end include two (2) additional 345/138 kV transformers at A.B. Brown and an additional 229 MVar of reactive support.

6.5 Partnering with Other Utilities

2022/2023 CEI South remains committed to partnering with other Indiana electric utilities where doing so provides the opportunity to more cost effectively construct generation. CEI South issued a broad request for proposals as part of this IRP process. While other Indiana electric utilities could have submitted bids, none were received. Many of the projects CEI South is pursuing are being constructed by developers, some of whom are developing projects for other Indiana electric utilities already. Some of the projects submitted in response to the RFP could likely be split between CEI South and other electric utilities. Other projects being pursued by CEI South, such as converting Culley Unit 3 to gas, are not of sufficient size or scope to warrant partnership with other Indiana utilities. CEI South remains abreast of other Indiana electric utilities' IRPs and will dialogue with them, as appropriate, around appropriate partnership opportunities. CEI

South maintains strong relationships with the other Indiana investor-owned utilities and will utilize these resources to explore appropriate partnerships.

SECTION 7
MODEL INPUTS AND ASSUMPTIONS

7.1 RESOURCE MODEL (EnCompass)

EnCompass was the primary tool for conducting CEI South's analysis. EnCompass is an industry standard chronological unit commitment and dispatch model with extensive presence throughout the electric power industry. The model uses a mixed integer programming approach ("MIP") to determine the optimal solution to capacity expansion, unit commitment, and economic dispatch problems, while observing real world constraints, such as emission reduction targets, transmission and plant operation limitations, renewable energy availability and mandatory portfolio targets.

The model can be run in several modes; two were utilized for this study. The Capacity Expansion mode was utilized to determine the least cost mix of existing and new generating assets that meets demand (electric load) over time and meets regulatory and reliability requirements. Then a detailed economic dispatch mode, where the portfolios that were made in the Capacity Expansion mode were run on a more granular level.

EnCompass is widely used by electric utilities, consulting agencies and other stakeholders to forecast generator performance and economics, develop IRPs, forecast power market prices and assess detailed impact of regulations and market changes affecting the electric power industry. Key inputs to the model include load forecasts, power plant costs and operating characteristics (e.g., heat rates), fuel costs, fixed and variable operating costs, outage rates, emission rates, and capital costs. The model assesses the potential performance, fixed and variable O&M costs and capital costs of prospective and existing generation/DSM resources and makes resource addition and retirement decisions for economic, system reliability and policy compliance reasons on a utility system (regional and nationwide scale). Outputs of the model include plant generation, gross margin, emissions, power prices, capacity additions, retirements and a variety of other metrics.

The model is equipped to determine least cost portfolios, and it can analyze portfolio risks by assessing portfolio performance across different future market outlooks. 1898 developed a stochastic framework to ensure these future market outlooks reflect both relevant historic uncertainty in key market drivers and cross relationships between different market drivers. For this reason, it is one of the most comprehensive, reliable and flexible tools in the market for conducting IRPs. 1898 has successfully conducted numerous IRPs for many utilities across the country. EnCompass has gained wide acceptance among electric utility executives, stakeholder groups and regulatory commissions.

To perform both the required deterministic (scenario based) and probabilistic (stochastic) modeling, using scenario narratives created with stakeholder input, 1898 developed five scenarios and a set of probability distributions for key market driver variables. These include both forecasts of each variable under the five scenario conditions and probabilistic distributions for demand growth (load), fuel costs (natural gas and coal), other variables were also varied in the risk analysis including environmental compliance costs (carbon) and capital costs. The sections below include a description of how these forecasts and distributions were developed.

7.2 REFERENCE CASE SCENARIO

CEI South developed a Reference Case forecast of key market drivers that collectively represent the expected or most likely future for each input variable. For key assumptions, including natural gas prices, coal prices and capacity prices, a range of views from various vendors were incorporated into a consensus forecast.

The Reference Case scenario is based upon consensus forecasts from several consultants. Hence, it is impossible to describe specifics regarding the assumptions driving each forecast. However, the Reference Case can be described in more general terms based upon consistency in general trends among the individual forecasts that comprise the consensus forecast. Generally, the forecast is characterized by reasonable and balanced levels of growth, best guess forecasts of market conditions, regulatory requirements and technological change. Typically, market participants under Reference Case conditions can adapt and adjust in a timely manner to changing market forces.

Short Term: In the short-term (2023-2024), the Reference Case assumes an overall positive sales growth. Residential customer annual consumption is expected to increase in the short term with this trend continuing in the medium-term and long-term. Commercial sales are expected to remain flat in the near term before declining slightly in the medium-term and long-term. Industrial sales are expected to increase significantly in the near term with the addition of a new large customer with slight growth expected in the long-term.

Natural gas prices are expected to continue declining in 2024 and 2025 compared to 2023, as U.S storage levels are expected to increase. In the short-term, the consensus forecasts show natural gas prices are expected to remain below $4.50/MMBtu. However, prices have dropped significantly since CEI South started the IRP in 2022 when Henry Hub prices spiked in the fall. The EIA's short term energy outlook shows 2023 prices below $3.00/MMBtu.

Meanwhile, coal prices decline in the near-term as domestic markets remain soft and the energy crisis in Europe eases. Exports of coal provide a small amount of upward pressure demand, but mine prices are expected to continue to decline in the short-term from the 2023 price of $3.87/MMBtu in the Illinois Coal Basin.

Coal plant retirements were high in 2015 driven by regulation including MATS and again in 2018 for economic reasons with retirements expected to continue as the fleet transition moves forward. Capacity additions fueled by natural gas are expected to continue to support the renewable resources that are planned to be added to the system. Data from the EIA AEO 2023 report anticipates a continued pace of capacity additions over the next few years with a significant buildout of renewable resources.[59]

[59] https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Narrative.pdf , EIA Annual Energy Outlook, page 9, U.S. Energy Information Administration

The Reference Case reflects the assumption that a carbon policy will be implemented on the national level and used costs associated with complying with the ACE Rule as proxy. In this IRP, CEI South is accounting for both direct CO_2 emissions and CO_2-equivalent (CO_2e) emissions.

Medium Term: In the medium-term (2025-2031), as in the short-term, energy efficiency standards and energy company sponsored DSM programs mostly offset the growth in energy sales from a growing residential customer base. However, overall load growth continues, driven by new C&I customers locating in the Midwest to take advantage of access to low-cost shale gas and through the adoption of EVs.

Natural gas prices at the Henry Hub in the medium-term are expected to remain relatively flat, with the consensus forecast anticipating prices in the $4.00-$4.90/MMBtu range. Natural gas markets prices have continued to decline in real time as CEI South performed its IRP analysis with the EIA Annual Energy Outlook predicting prices will continue to decline until 2028 where they bottom out near $2.80/MMBtu and only rise slightly the next few years ending near $3.00/MMBtu in 2031.

Coal prices in the Illinois Basin are expected to remain relatively flat in the medium-term, as the modest export market is unable to compensate for declining domestic demand. Consensus Illinois Basin prices at the mine have increased since the last IRP, averaging $2.98/MMBtu over the study period, with a steady increase over time.

Power prices, which were developed in EnCompass, decline along with natural gas prices over the first few years of the study period. This decline in prices levels out over the medium-term as a balance of more renewables continue integrating onto the grid and the customer base continues to grow, energy company operating costs continue to rise. Commodity markets recover in the medium-term, pushing up material costs and consequently capital costs. In addition, as the overall economy continues to improve and the unemployment rate remains near historically low levels, capital costs rise as competitive upward pressure remains on labor costs.

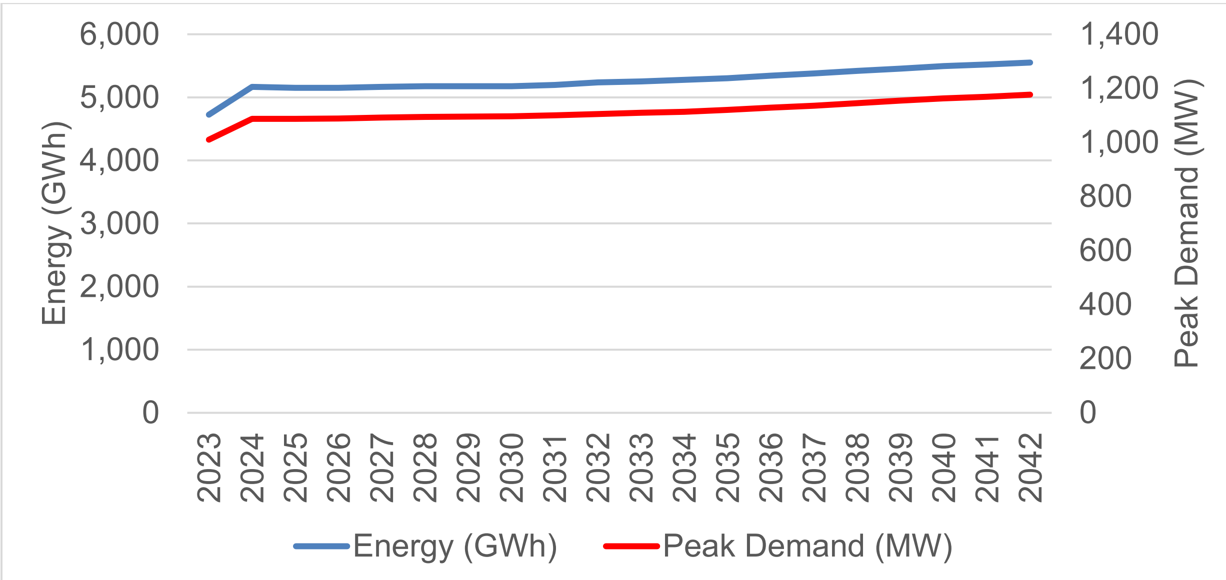
Long Term: In the long-term (2032-2042), the suite of market outcomes and drivers in the Reference Case settles into a pattern of moderate growth based on a well-balanced market. Energy sales grow at a moderate pace (0.7% CAGR for 2023-2042)[60]. The consensus forecast for Henry Hub has prices reaching $4.76/MMBtu by 2042 (in real 2023$), while ILB coal prices at the mine increase to $2.33/MMBtu by 2042 (in real 2023$). Energy demand grows as electric vehicle sales take hold and as residential and commercial customers electrify their energy use, but this is partially offset by continued gains in distributed solar generation, demand side management and energy efficiency measures. Domestic shale gas resources help to keep fuel cost growth to a relatively low level. Capital costs increase at a measured pace as the GDP growth rate averages two percent or more and as higher borrowing costs come from long-term rising interest rates. Capacity additions and retirements continue at a reasonable rate as the fleet of power plants maintains a healthy rate of turnover.

7.2.1 Input Forecasts

The long-term energy and demand forecast for the CEI South service territory was developed for CEI South by Itron. The long-term energy and demand forecast for the MISO market comes from the System Forecasting for Energy Planning section of MISO's website.[61] For more information, please see Section 4 Customer Energy Needs and Technical Appendix 4.1. The forecast is based on a combination of historical usage trends and a bottom-up approach to drivers such as residential and commercial demand, industrial load, appliance saturation, energy efficiency, long-term weather trends, customer-owned generation, electric vehicle adoption and an outlook for economic factors.

[60] Does not include impact of company sponsored EE programs.
[61] https://www.misoenergy.org/planning/policy-studies/system-forecasting-for-energy-planning/#nt=%2Freport-study-analysistype%3ALoad%20Forecast&t=10&p=0&s=FileName&sd=desc

Figure 7.1 – Reference Case CEI South Load Forecast (MWh and MW)



For both natural gas and coal CEI South used a "consensus" Reference Case view of expected prices by averaging forecasts from several sources. For natural gas and coal, forecasts from Wood Mackenzie, ABB, S&P Global, & EVA were averaged. For capacity, CEI South used a consensus forecast, using ABB and S&P Global[62]. This helps to capture views from several experts and allows CEI South to be more transparent in the planning process. The consensus forecast for Henry Hub was adjusted based on historical price separation between Henry Hub and delivered gas prices to the CEI South system.

[62] CEI South did not have access to a capacity forecast from Wood Mackenzie or EVA

Figure 7.2 – Reference Case Natural Gas Price Forecast (2023$/MMBtu)

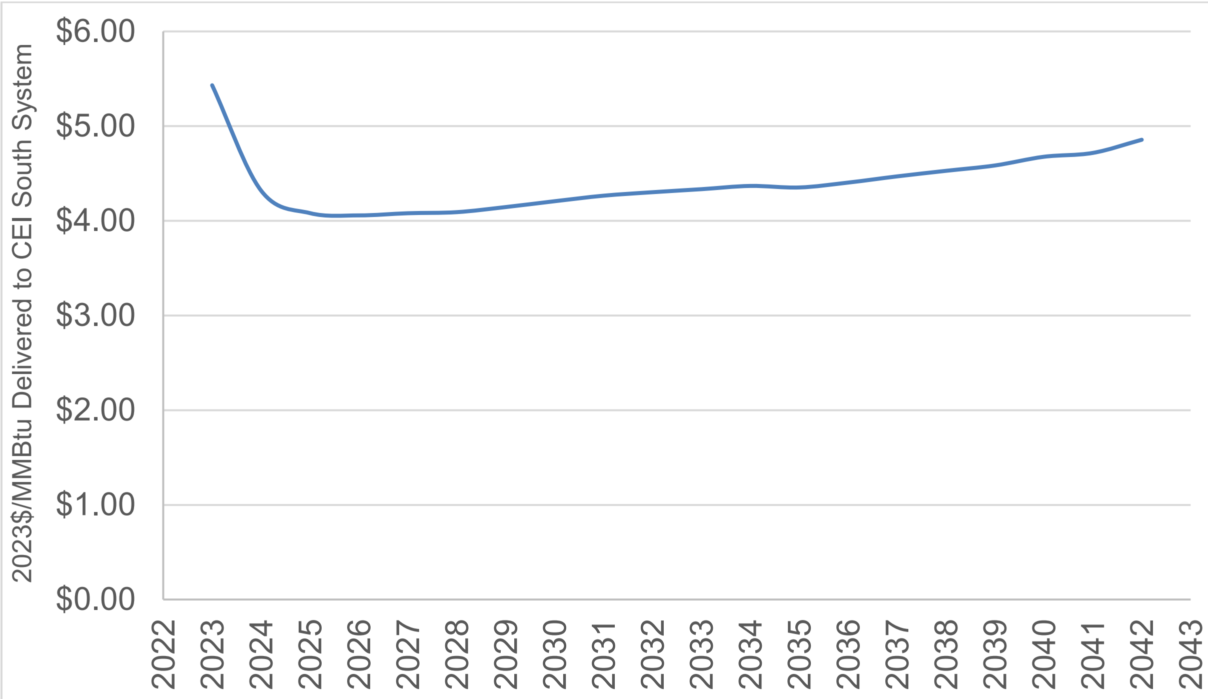
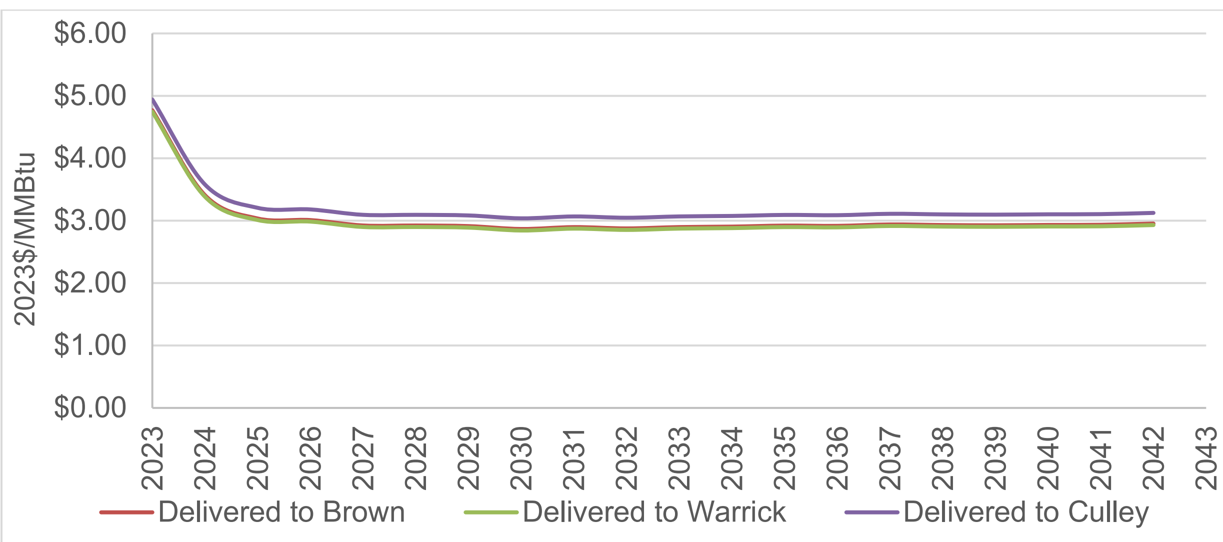


Figure 7.3 – Reference Case Coal Price Forecast (2023$/MMBtu)

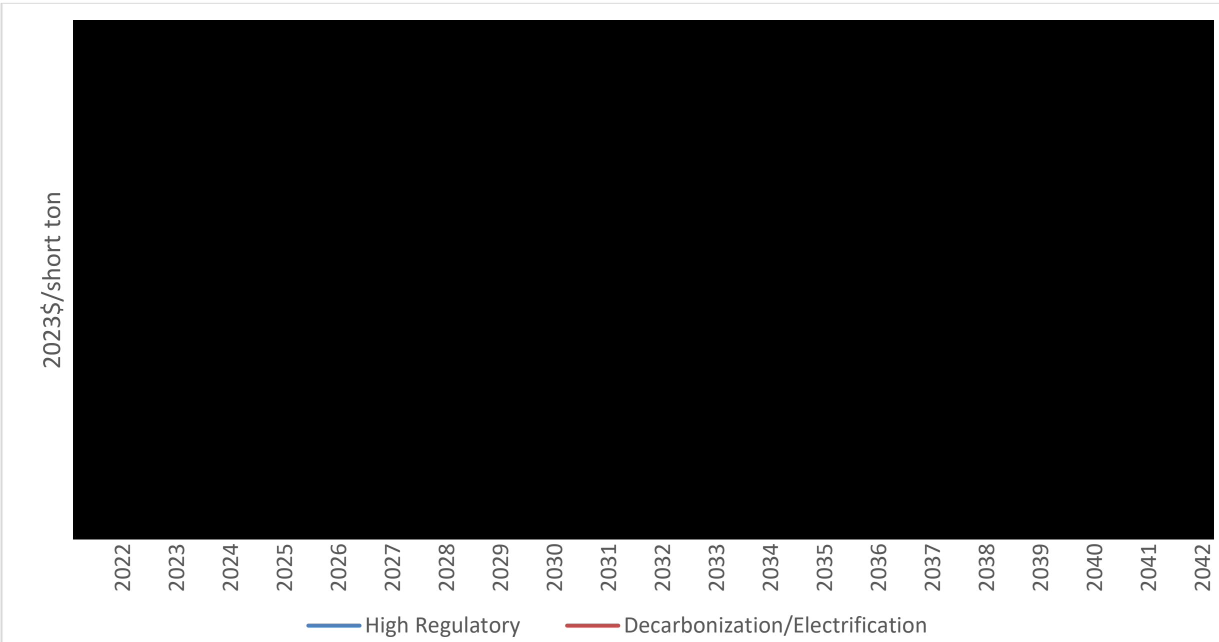


During this analysis, no comprehensive national legislation of carbon emissions existed in the United States. Efforts to enact federal policy covering carbon emissions from major sources have occurred over the years. This included efforts by the U.S. Congress to pass a national cap-and trade regime, the EPA's regulation of GHG emissions from new and existing power generators which culminated in the ACE rule (which was modeled in this IRP as a proxy for future carbon costs), and more recently proposals in the U.S. Congress for carbon taxes and comprehensive clean energy targets.

Action to limit carbon emissions has increased in recent years with states taking the lead in defining low and no-carbon generation requirements. Indiana does not have a state policy limiting or otherwise placing a price on carbon emissions from power generation. However, the potential remains for enactment of such a policy at the national level over the study period. To account for this uncertainty, in the reference case the ACE rule was used as a proxy for carbon regulation for coal generators. Costs were included in the modeling to improve the efficiency of F.B. Culley 3 which would reduce their overall emissions. A carbon tax was assumed in the High Regulatory and Decarbonization/Electrification scenarios. In the High Regulatory scenario, a carbon tax starts in [redacted] per ton and increases over the planning period to [redacted] per ton. In the Decarbonization/Electrification scenario the tax starts in [redacted] per ton and increases over the planning period to [redacted] per ton.

On May 11, 2023 EPA released a pre-publication version of a new GHG proposal which seeks to establish new GHG emission reduction requirements for existing coal-fired EGUs and new and existing gas-fired EGUs. New regulatory language accompanying this proposal was released on May 15, 2023. Upon publication EPA will commence a notice and comment period and it is anticipated that the new proposal will receive a significant number of public comments from a wide range of stakeholders.

Figure 7.4 – Confidential High Regulatory and Decarbonization/Electrification Scenarios CO_2 Price Forecast (2023$/short ton)[63]



Capital costs in the near to midterm (through 2026) were based on bids received in the All-Source RFP, as described in Section 6.1.6 Grouping. As described in Section 6, non-renewable capital costs were developed by 1898 & Co. as well as long term solar, wind and battery storage costs. Long-term capital costs for storage, solar, and wind were adjusted to reflect bid pricing in the near term and then the NREL capital cost indexes were used to adjust prices beyond the bid period. Forward capital cost estimates can be found in Figure 6-18.

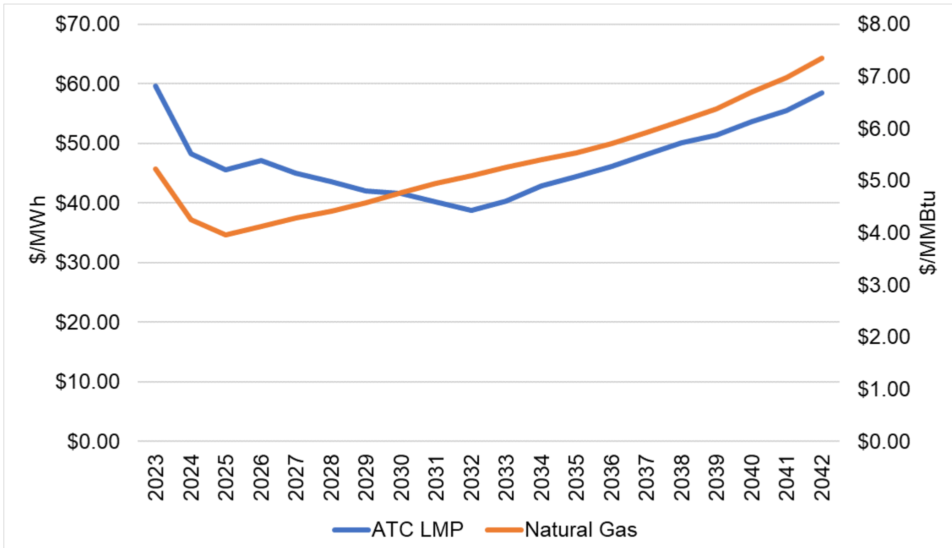
7.2.2 Energy Prices

Energy prices as an input into the IRP model were developed by 1898 EnCompass software. The starting model for the analysis was the national database licensed from Horizons Energy, LLC. Updates to the National Database were made to specifically align the input assumptions with the IRP Scenario assumptions. A summary of around the clock

[63] Proprietary forecasts from one vendor, ABB

("ATC") power price forecast can be seen below in Figure 7.5, which also illustrates the macro correlation to natural gas prices over the study period.

Figure 7.5 – Reference Case Power Price Forecast (Nominal $/MWh)



7.2.3 Environmental Regulations

The current modeling analysis includes relevant costs primarily focused on evaluation of alternatives to comply with the CCR, ELG, 316(b) and ACE rule proxy requirements where applicable. All costs presented below are preliminary screening level estimates used for modeling purposes only. Individual elements of the estimate may go up or down depending on final design specifications, permit requirements, and vendor bids.

7.2.3.1 Effluent Limitations Guidelines (ELG)

A. B. Brown: ELG related changes would need to include conversion to dry bottom ash, upgrades to the dry fly ash system, a new landfill that can handle scrubber product and ash and a new system to handle process waters. Costs for these changes were not included in the study due to the retirement of Units 1 and 2 eliminating the need for these changes and associated expenditures.

F. B. Culley: Unit 3 is equipped with dry fly ash and dry bottom ash systems, thereby eliminating transport water discharges. The Spray Dryer Evaporator Zero Liquid Discharge system has been completed and is online, meeting the ELG requirements that are incorporated into the NPDES permit, eliminating the discharge of FGD Wastewater.

For Warrick Unit 4, CEI South modeled its share of the total capital spend.

7.2.3.2 Coal Combustion Residuals (CCR)

For A. B. Brown and F. B. Culley, it was assumed ash ponds would be closed at the end of their useful life. The timing of the closures is based on forced closure (i.e., exceedance of GWPS and failure of aquifer location restriction) and compliance with the Site-Specific Alternatives to Initiate Closure that were submitted to U.S. EPA under the requirements of the CCR Part A rule. The base cost for the closures does not change regardless of future generation. CEI South has not historically utilized the ponds at the Warrick power plant for its share of the CCR generated by WPP4 and therefore is not liable for pond closure costs.

7.2.3.3 Affordable Clean Energy (ACE)

As described earlier, In June 2019 EPA finalized the ACE rule, which replaces the Clean Power Plan from 2015 (a cap and trade program which sought to lower CO_2 emissions from existing power plants by 30% from 2005 levels). This rule was vacated in January of 2019, but CEI South used ACE as a proxy for carbon legislation in the reference case. Since A.B. Brown 1 & 2 and F.B. Culley 2 are planned for retirement in 2023 and 2025 respectively no ACE costs were included for these units. Similarly, since CEI South plans to exit joint operations of Warrick 4 in 2023 no ACE costs were included for this unit.

Figure 7.6 – ACE Cost

Unit	Total ACE Upgrade Cost (2023$)
A.B. Brown 1	N/A
A.B. Brown 2	N/A
F.B. Culley 2	N/A
F.B. Culley 3	$34 Million
Warrick 4	N\A

7.2.3.4 316(b)

EPA issued its final rule regarding Section 316(b) of the Clean Water Act. The rule establishes requirements for Cooling Water Intake Structures ("CWIS") at existing facilities.

This requirement applies to both F. B. Culley and Warrick. At this time, based on available information for A. B. Brown, IDEM has made a Best Technology Available determination that the existing cooling water intake structures represent best technology available to minimize adverse environmental impact. This determination will be reassessed at the next NPDES permit reissuance. Standard fine mesh and fish friendly screens and fish return systems were estimated to be $21M at F. B. Culley. The F.B. Culley NPDES renewal permit was issued on February 1, 2023 with a March 1, 2023 effective date. IDEM made the determination that the Best Technology Available ("BTA") for both impingement and entrainment is 1.0 mm wedgewire screens, and the facility is required to submit additional information regarding site specific feasibility studies with respect to both determinations, after which IDEM will reevaluate these determinations. Warrick is required to install modified travelling screens and a fish handling and return system at Warrick. CEI South is not responsible for its share of total capital.

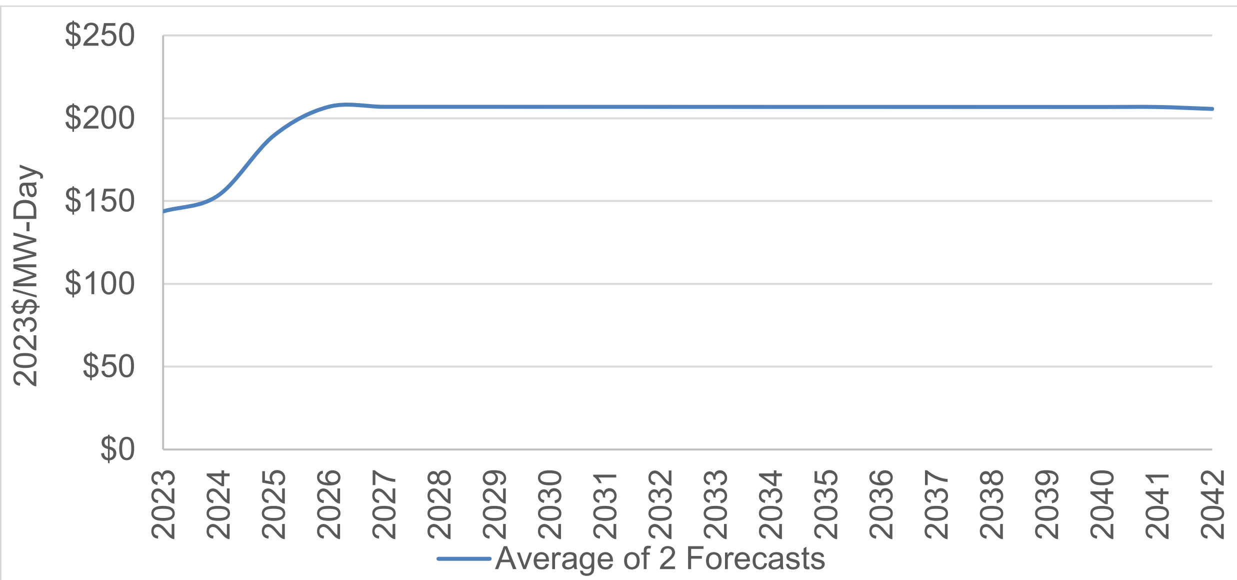
7.2.3.5 Market Capacity Price

The MISO capacity price has been difficult to predict as was shown by the results of the 2022-2023 MISO Planning Resource Auction. All of MISO's North\Central region cleared at Cost of New Entry ("CONE") because of a capacity shortfall. While the Planning Resource Auction did not clear at CONE ($270/MW-Day[64]) for the 2023/2024 planning year, this trend is expected to continue. To put this number in perspective, the annual capacity value of a resource that receives 100 MWs of accreditation at CONE is nearly $10 million. As MISO has transitioned to a seasonal construct the seasonal accreditation

[64] MISO annual CONE calculation –Page 9 - https://cdn.misoenergy.org/MISO%202022%20Annual%20CONE%20filing626484.pdf

for new wind and solar resources varies from 18%-40% and 5%-50%[65] respectively while a fossil steam resource similar in size to F.B. Culley would receive accreditation near ~90%. While some capacity will be bought or sold nearly every year since load, planning reserve margin requirements, and resource accreditation vary by season. Most new supply side resources, such as generating units, come in large blocks with 30+ year expected lifetimes. A portfolio that lacks adequate capacity resources introduces cost risk the CEI South customers. For modeling purposes, CEI South used a consensus forecast, utilizing ABB and S&P Global for Reference Case MISO Indiana capacity prices.

Figure 7.7 – Capacity Market Value Forecast (2023$/MW-Day)



7.2.4 Additional Modeling Considerations

CEI South received approval in 2022 from the Commission to replace A.B. Brown Units 1&2 with two natural gas combustion turbines. As such, the units were modeled in all portfolios throughout the planning period. Likewise, renewables projects for which CEI South has filed for a CPCN with the IURC since the last IRP have been included in all portfolios. These projects are described in Section 1.3.1 Generation. F.B. Culley coal unit

[65] Wind and solar class averages of PY 23-24 – MISO, 2023; https://cdn.misoenergy.org/Wind%20and%20Solar%20Class%20Average%20SAC627924.pdf

3 could retire economically within the model beginning December 31, 2029. This allows for enough time for replacement generation to be acquired. Note that a conversion of F.B. Culley 3 to natural gas may occur by 2027 due to the MISO interconnection transfer process and six month construction timeline.

Modeling also included other fixed considerations. All candidate portfolios were designed to include energy efficiency equivalent to 1.2% of sales, in the near-term years of 2025-2027. The process used to identify this level is described in section 6.3.2.5 DSM Resource Optimization Process.

As described in section 2.5, Recent legislation was passed in Indiana, capping the reliance on MISO's planning resource auction at 15%. This limit helps to ensure portfolios do not overly rely on capacity purchases in the long term. There is more certainty in the near term about what might be available through bi-lateral contracts. As such, early years included higher thresholds of 300 MWs through 2025 and 180 MWs 2026-2028.

The modeling is performed in 2 steps, the first of which is the capacity expansion step, where EnCompass determines the resource retirement and replacement decisions and timing. The second is a chronological hourly dispatch using the inherited portfolio for the entire study period. For portfolios to be built, the model did not rely on capacity sales into the market, during the capacity expansion step. Then during the detailed dispatch step, excess capacity was allowed to be sold once the portfolio was locked down.

7.3 ALTERNATE SCENARIOS

To develop several alternative scenarios for its IRP process, CEI South used a construct that allowed various regulatory and market conditions across four alternative scenarios. As previously mentioned, there were two purposes for these scenarios. First, each alternative market scenario was used to develop a least cost portfolio. Second, the final list of portfolios was evaluated against each alternative market scenario.

The alternate scenarios, created with stakeholder input, included the High Regulatory scenario, the Market Driven Innovation scenario, the Decarbonization/Electrification scenario and the Continued High Inflation & Supply Chain Issues scenario. 1898 & Co. provided the qualitative descriptions and quantitative inputs for each of these scenarios, which were based on collaboration between CEI South, 1898 & Co. and stakeholders.

7.3.1 Description of Alternate Scenarios

As described in Section 2.4, the second purpose of developing these "boundary" scenarios was to test a relevant range for each of the key market drivers (gas, coal, CO_2, load and capital costs) on how various technologies perform under boundary conditions.

7.3.1.1 High Regulatory

The High Regulatory scenario depicts a future of higher regulation resulting in higher costs of energy and some resulting economic slowdown. A high carbon fee is implemented throughout the planning horizon (2023 - 2042). A fracking ban is imposed, driving up the cost of natural gas notably in the long-term as supply dramatically shrinks. Declining demand for coal is offset by regulations that increase the coal price resulting in coal prices higher than to the Reference Case as coal mines close and remaining coal producers can charge more per ton, passing costs of new regulations on to remaining customers. Although technological innovation is stifled, renewables and battery storage receive government incentives, allowing costs to fall even as demand for these technologies increases. Utility-sponsored energy efficiency costs rise over time as the cost for regulatory compliance rises.

7.3.1.2 Market Driven Innovation

The Market Driven Innovation scenario includes transition to a more free market leads to new and advanced technology, driving down energy prices. Less government influence drives competition among competing fuels and no carbon tax results in lower power prices from natural gas and coal resources. Increased energy usage is a direct result of less government influence reducing overall costs. Further technological innovation to lower energy cost is spurred by an increase in demand for renewable and storage resource options. This advancement in technological innovation drives more opportunities for energy efficiency programs. Energy efficiency programs are predicted to be more cost effective with increased load. In addition, less codes and standards changes allow utility sponsored energy efficiency programs to transform the market at a lower incentive cost.

7.3.1.3 Decarbonization/Electrification

The Decarbonization/Electrification scenario assumes that utility-sponsored energy efficiency costs are below base levels due to technology advances, allowing for new and innovative ways to partner with customers to save energy. As technology costs fall, customers begin to move towards electrification, driving more electric vehicles and higher adoption of rooftop solar/energy storage and trend towards highly efficient electric heat pumps in new homes and other buildings. The switch to electrification causes an increase in load and natural gas supply; however, the natural gas prices remain at Reference Case level due to methane regulations. A mid-level carbon tax is imposed causing demand for coal to decrease and supply constraints cause coal prices to increase. Technological improvements to lower costs are offset by higher demand and rising land and labor costs.

7.3.1.4 Continued High Inflation and Supply Chain Issues

The Continued High Inflation and Supply Issues scenario assumes a shortage in labor and materials, costs for new technologies and fuels are increasing. Higher labor and delivery costs reduced the supply of fuel leading to higher coal and natural gas prices. Load demand is negatively affected by high inflation causing reduced economic output. Like the Reference Case, no carbon price is imposed. Continued disruptions in the supply chain along with high inflation leads to higher costs for renewables and storage. Reduction in load results in less potential of energy efficiency acquisition both for incentives passed to customers and implementation of programs as implementers experience increased cost. In addition, shortage of EE equipment leads to increased cost of high-efficient measures.

7.3.2 Coordinated Forecasts for Alternate Scenarios

The qualitative description of alternate scenarios described in Section 7.3.1 were next translated into quantitative inputs for use as modeling inputs. The steps in this process were described in Section 2.

- Probability distributions were developed for each input variable.
- A table was developed that determined whether the variable would be above or below the Reference Case in the short, mid and long term.
- Values in specific years were developed by moving up or down one standard deviation (for gas sometimes two standard deviations) from the mean or reference forecast.
- Smoothing occurred to reach interim year values.

This was done using a probabilistic modeling framework, described below, which allowed the development of higher and lower forecasts, relative to the Reference Case for monthly natural gas prices, CO_2 prices, coal prices, peak load for CEI South as well as surrounding markets (MISO, PJM and SERC) and capital costs for renewables and storage technologies.

7.3.2.1 Probability Distributions

To perform the stochastic analysis that develops 200 sets input variables, probability distributions that describe uncertainty were developed for the key market driver variables discussed above (natural gas prices, coal prices, CO_2 prices, peak load and renewables capital costs). These probability distributions were developed by defining the uncertainty around each of the variables on a monthly basis. Lognormal probability distributions were assigned for natural gas prices, coal prices and peak load. Discreet probability distributions were defined for CO_2 prices and renewables capital costs. Once probability distributions around each of the inputs were defined, the lognormal probability distributions were inputted into EnCompass. Using EnCompass' stochastic modeling, 200 iterations were run for natural gas pricing, coal pricing and peak load to form 200 sets of inputs. Probability distributions for CO_2 prices and for renewables capital costs were then assigned to the 200 sets of inputs to develop 200 complete sets of inputs. The methodologies for developing the probability distributions used in the stochastics process are Described in the Technical Appendix 11.6.

7.3.2.2 Model Inputs

The following graphs illustrate the key market driver inputs across all the alternate scenarios.

Figure 7.8 – CEI South Peak Load (MW) Alternate Scenarios

Year	Reference Case	High Regulatory	Market Driven Innovation	Decarbonization/ Electrification	Continued High Inflation & Supply Chain Issues
2022	1,010	996	1,017	1,017	996
2023	1,010	996	1,017	1,017	996
2024	1,087	1,068	1,097	1,097	1,068
2025	1,087	1,066	1,098	1,098	1,066
2026	1,088	1,064	1,101	1,101	1,064
2027	1,092	1,065	1,105	1,105	1,065
2028	1,095	1,065	1,110	1,110	1,065
2029	1,095	1,062	1,112	1,112	1,062
2030	1,096	1,059	1,115	1,115	1,059
2031	1,100	1,061	1,120	1,120	1,061
2032	1,105	1,060	1,128	1,128	1,060
2033	1,110	1,059	1,135	1,135	1,059
2034	1,114	1,059	1,142	1,142	1,059
2035	1,120	1,060	1,150	1,150	1,060
2036	1,128	1,061	1,162	1,162	1,061
2037	1,136	1,063	1,174	1,174	1,063
2038	1,145	1,067	1,185	1,185	1,067
2039	1,154	1,071	1,197	1,197	1,071
2040	1,162	1,071	1,209	1,209	1,071
2041	1,169	1,070	1,220	1,220	1,070
2042	1,177	1,072	1,231	1,231	1,072

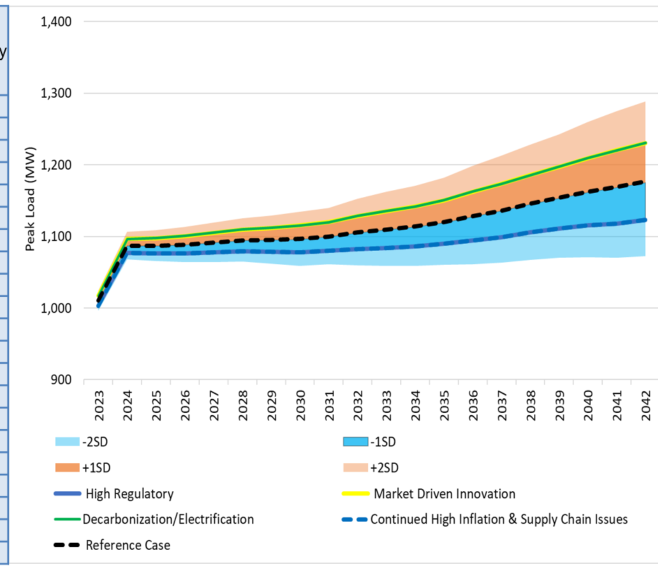


Figure 7.9 – Coal (Illinois Basin) Alternate Scenarios ($/MMBtu)

Year	Reference Case	High Regulatory	Market Driven Innovation	Decarbonization/ Electrification	Continued High Inflation & Supply Chain Issues
2022	$2.89	$2.89	$2.89	$2.89	$2.89
2023	$4.39	$4.39	$4.39	$4.39	$4.39
2024	$3.09	$3.09	$3.09	$3.09	$3.09
2025	$2.77	$3.13	$2.77	$3.13	$3.13
2026	$2.81	$3.16	$2.62	$3.16	$3.16
2027	$2.78	$3.19	$2.46	$3.19	$3.19
2028	$2.85	$3.22	$2.47	$3.22	$3.22
2029	$2.90	$3.31	$2.49	$3.31	$3.31
2030	$2.91	$3.34	$2.48	$3.34	$3.34
2031	$3.02	$3.48	$2.55	$3.48	$3.48
2032	$3.06	$3.52	$2.60	$3.52	$3.52
2033	$3.16	$3.67	$2.64	$3.67	$3.67
2034	$3.24	$3.77	$2.71	$3.77	$3.77
2035	$3.33	$3.88	$2.79	$3.88	$3.88
2036	$3.41	$4.00	$2.81	$4.00	$4.00
2037	$3.51	$4.12	$2.91	$4.12	$4.12
2038	$3.58	$4.22	$2.94	$4.22	$4.22
2039	$3.66	$4.34	$2.97	$4.34	$4.34
2040	$3.75	$4.45	$3.05	$4.45	$4.45
2041	$3.84	$4.58	$3.10	$4.58	$4.58
2042	$3.96	$4.71	$3.21	$4.71	$4.71

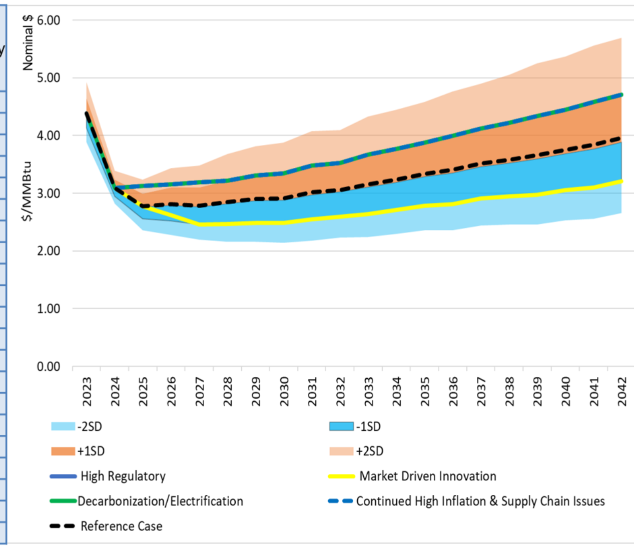


Figure 7.10 – Natural Gas (Henry Hub) Alternate Scenarios ($/MMBtu)

Year	Reference Case	High Regulatory	Market Driven Innovation	Decarbonization/ Electrification	Continued High Inflation & Supply Chain Issues
2022	$5.82	$5.82	$5.82	$5.82	$5.82
2023	$5.68	$5.68	$5.68	$5.68	$5.68
2024	$4.65	$4.65	$4.65	$4.65	$4.65
2025	$4.43	$5.64	$4.29	$4.43	$5.04
2026	$4.50	$6.63	$3.93	$4.50	$5.42
2027	$4.57	$7.62	$3.57	$4.57	$5.80
2028	$4.70	$8.61	$3.21	$4.70	$6.19
2029	$4.87	$8.85	$3.34	$4.87	$6.39
2030	$5.05	$9.44	$3.38	$5.05	$6.70
2031	$5.23	$10.00	$3.44	$5.23	$7.01
2032	$5.39	$10.51	$3.49	$5.39	$7.28
2033	$5.55	$11.01	$3.55	$5.55	$7.55
2034	$5.72	$11.47	$3.62	$5.72	$7.81
2035	$5.83	$11.55	$3.73	$5.83	$7.92
2036	$6.03	$11.68	$3.93	$6.03	$8.12
2037	$6.26	$12.09	$4.08	$6.26	$8.42
2038	$6.48	$12.42	$4.26	$6.48	$8.69
2039	$6.71	$12.64	$4.47	$6.71	$8.94
2040	$7.00	$13.19	$4.66	$7.00	$9.32
2041	$7.22	$13.58	$4.81	$7.22	$9.60
2042	$7.59	$14.31	$5.06	$7.59	$10.11

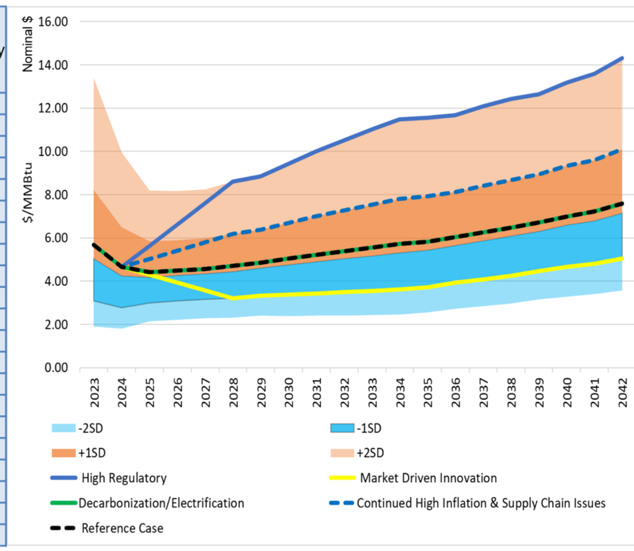


Figure 7.11 – Solar Capital Costs Alternate Scenarios (100 MW) ($/kW)[66]

Year	Reference Case	Low	High	NREL
2022	$1,943	$1,700	$2,057	$1,172
2023	$1,943	$1,700	$2,057	$1,149
2024	$1,943	$1,700	$2,057	$1,125
2025	$1,943	$1,700	$2,057	$1,100
2026	$1,943	$1,700	$2,057	$1,073
2027	$1,891	$1,663	$2,104	$1,044
2028	$1,836	$1,626	$2,152	$1,014
2029	$1,777	$1,589	$2,201	$981
2030	$1,714	$1,552	$2,252	$946
2031	$1,737	$1,515	$2,303	$959
2032	$1,761	$1,478	$2,356	$973
2033	$1,785	$1,442	$2,410	$986
2034	$1,809	$1,405	$2,465	$999
2035	$1,834	$1,368	$2,522	$1,013
2036	$1,858	$1,331	$2,580	$1,026
2037	$1,883	$1,294	$2,639	$1,040
2038	$1,908	$1,257	$2,699	$1,054
2039	$1,933	$1,220	$2,761	$1,067
2040	$1,958	$1,183	$2,825	$1,081
2041	$1,983	$1,146	$2,889	$1,095
2042	$2,009	$1,109	$2,956	$1,109

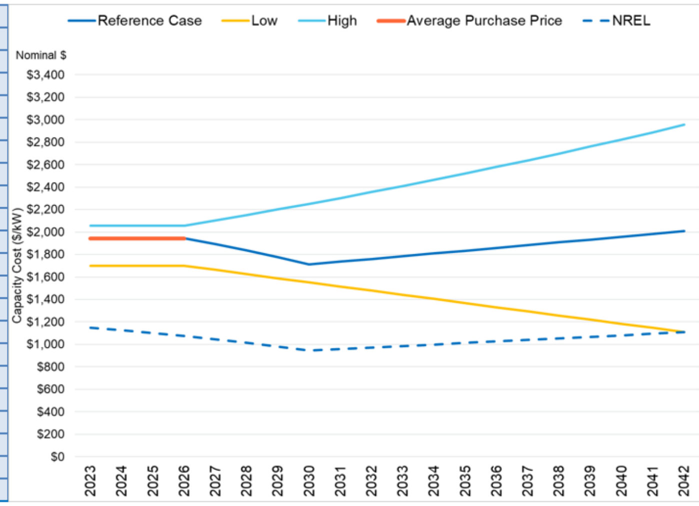
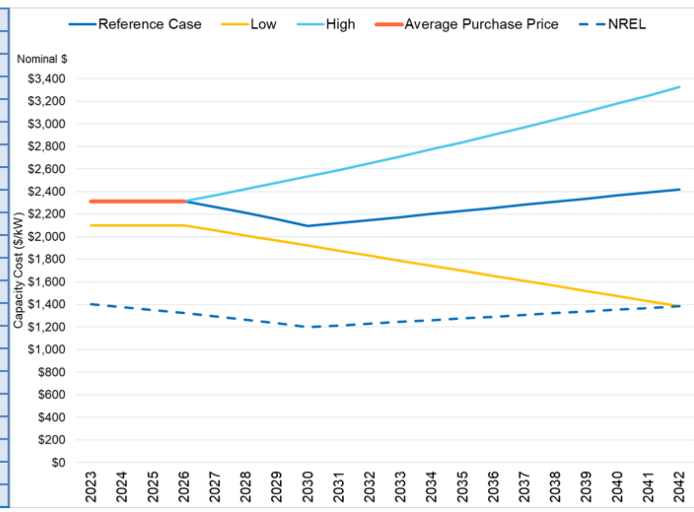


Figure 7.12 – Wind Capital Costs Alternate Scenarios (200 MW) ($/kW)[67]

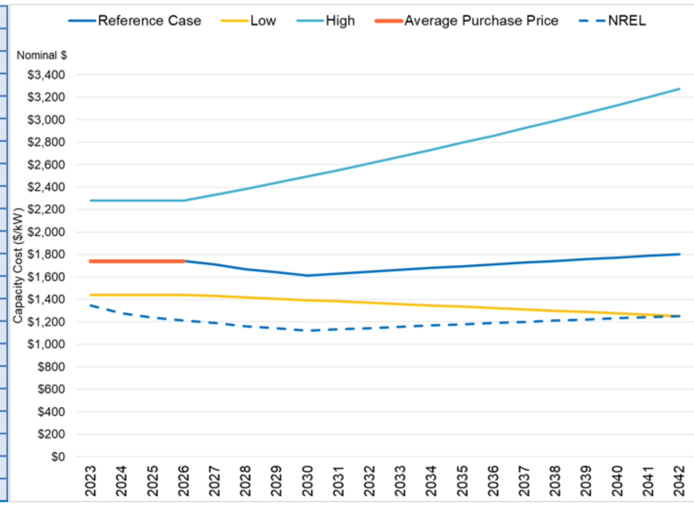
Year	Reference Case	Low	High	NREL
2022	$2,314	$2,100	$2,314	$1,423
2023	$2,314	$2,100	$2,314	$1,400
2024	$2,314	$2,100	$2,314	$1,377
2025	$2,314	$2,100	$2,314	$1,351
2026	$2,314	$2,100	$2,314	$1,325
2027	$2,265	$2,055	$2,367	$1,297
2028	$2,212	$2,011	$2,421	$1,266
2029	$2,155	$1,966	$2,477	$1,234
2030	$2,095	$1,921	$2,533	$1,199
2031	$2,121	$1,877	$2,592	$1,214
2032	$2,148	$1,832	$2,651	$1,230
2033	$2,175	$1,787	$2,712	$1,245
2034	$2,202	$1,743	$2,774	$1,260
2035	$2,229	$1,698	$2,837	$1,276
2036	$2,256	$1,653	$2,903	$1,291
2037	$2,283	$1,609	$2,969	$1,307
2038	$2,310	$1,564	$3,037	$1,323
2039	$2,337	$1,519	$3,107	$1,338
2040	$2,365	$1,474	$3,178	$1,354
2041	$2,392	$1,430	$3,251	$1,369
2042	$2,419	$1,385	$3,325	$1,385



[66] High Regulatory and Market Driven Innovation Scenarios were Low; Decarbonization/Electrification was at Reference Case; and Continued High Inflation & Supply Chain issues was High.
[67] High Regulatory and Market Driven Innovation Scenarios were Low; Decarbonization/Electrification was at Reference Case; and Continued High Inflation & Supply Chain issues was High.

Figure 7.13 – Lithium-Ion 50 MW / 200 MWh Battery Storage Capital Costs Alternate Scenarios ($/kW)[68]

Year	Reference Case	Low	High	NREL
2022	$1,742	$1,443	$2,279	$1,434
2023	$1,742	$1,443	$2,279	$1,344
2024	$1,742	$1,443	$2,279	$1,277
2025	$1,742	$1,443	$2,279	$1,236
2026	$1,742	$1,443	$2,279	$1,211
2027	$1,711	$1,431	$2,331	$1,190
2028	$1,669	$1,419	$2,385	$1,160
2029	$1,643	$1,407	$2,439	$1,142
2030	$1,614	$1,395	$2,495	$1,122
2031	$1,632	$1,383	$2,553	$1,134
2032	$1,648	$1,372	$2,611	$1,146
2033	$1,664	$1,360	$2,671	$1,157
2034	$1,680	$1,348	$2,732	$1,168
2035	$1,696	$1,336	$2,795	$1,179
2036	$1,712	$1,324	$2,859	$1,190
2037	$1,727	$1,312	$2,924	$1,201
2038	$1,743	$1,300	$2,991	$1,212
2039	$1,758	$1,289	$3,060	$1,222
2040	$1,773	$1,277	$3,130	$1,233
2041	$1,788	$1,265	$3,202	$1,243
2042	$1,802	$1,253	$3,275	$1,253



68 High Regulatory and Market Driven Innovation Scenarios were Low; Decarbonization/Electrification was at Reference Case; and Continued High Inflation & Supply Chain issues was High.

SECTION 8
PORTFOLIO DEVELOPMENT AND EVALUATION

8.1 PORTFOLIO DEVELOPMENT

CEI South developed a wide range of portfolios for scenario modeling in the dispatch module of EnCompass and ultimately for the probabilistic modeling portion of this IRP process. Working with external stakeholders and building upon feedback from the IURC Director's Report from the 2019/2020 IRP, CEI South developed 10 portfolios for evaluation that included the use of its last coal plant (status quo) for comparative cost and performance benchmarking purposes, scenario-based portfolios optimized under widely varying market conditions, portfolios designed to provide insights around existing resource decisions, diversified portfolios with a balanced mix of generation technology types and renewables-focused portfolios designed with input from stakeholders. Each portfolio was constructed with the option to include near-term solar, wind and battery storage options, from the All-Source RFP solicitation. Medium-term and long-term resource options were available for selection from a combination of sourcing including the All-Source RFP as well as a comprehensive technology assessment performed by 1898 & Co. used to fill in resource options that were not provided in the RFP (where available from prices used from RFP data and trended based on NREL curves into the future). All portfolios were designed to include energy efficiency and demand response programs. Demand Side Management program options were modeled in addition to resource alternatives. Income Qualified Weatherization ("IQW"), Demand Response Legacy, Demand Response Industrial and Residential Low-Medium were implemented in all portfolios for all model years.

8.1.1 Key IRP Portfolio Decisions

CEI South strived to take into consideration the many diverse interests of a broad range of stakeholders. Candidate portfolios were developed with direct and indirect input from stakeholders. A key decision in the IRP process was the conversion or retirement decision for F.B. Culley 2 and 3. In addition, with MISO's shift to a seasonal construct, CEI South built portfolios to address potential capacity short falls across all seasons. Ultimately, a wide range of deterministic portfolios were created and analyzed to provide insight around the F.B. Culley 2 and 3 decisions along with various future resource mix options.

8.1.2 Scenario-Based and Deterministic Portfolios

Scenario-based portfolios (Reference Case, High Regulatory, Market Driven Innovation, Decarbonization/Electrification, and Continued High Inflation & Supply Chain Issues) were developed to evaluate various regulatory constructs, economic and market conditions and technological progress. In general, the scenario-based portfolios move from Market Driven Innovation to High Regulatory, with intermediate levels of regulation characterized by the Decarbonization/Electrification and Continued High Inflation & Supply Chain Issues portfolios.

While the Reference Case is considered the most likely future, the alternative scenario-based portfolios were developed to bookend the Reference Case with higher than, lower than, or similar inputs to the Reference Case.

Figure 8.1 – Scenario Based Portfolios

Year	Reference Case	Continued High Inflation & Supply Chain Issues	Market Driven Innovation	High Regulatory	Decarbonization/ Electrification
2024	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (200MW) Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Wind (600MW) Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)
2026				Wind (200MW) Solar + Storage (60 MW)	
2027	CCGT Conversion	Wind North (200MW)	CCGT Conversion		CCGT Conversion
2028				Storage (100MW)	
2029	Retire FB Culley 3	Retire FB Culley 3	Retire FB Culley 3	Retire FB Culley 3 Storage (100MW)	Retire FB Culley 3
2030		Storage (50 MW) Wind North (400MW)			Wind North (200MW)
2031		Storage (10MW)			
2032		Long Duration Storage (300MW)		Long Duration Storage (300MW)	Long Duration Storage (300MW) Wind North (200MW)
2033	Wind North (600MW)	Wind North (400MW)		Wind North (400MW)	Wind North (600MW)
2041			Storage (10MW)	Solar (100MW)	
2042			Storage (10MW)	Solar (200MW)	

In addition to scenario-based portfolios, deterministic portfolios were created to test various solutions to key decisions needed from this IRP. For example, converting F.B.

Culley 2 and/or F.B. Culley 3 to gas, retiring F.B. Culley 2 by 2025, and retiring F.B. Culley 3 by 2029, 2035, or continuing operations were all strategies included in deterministic portfolios. Within these F.B. Culley 3 retirement portfolios, various resource mixes of non-thermal (wind, solar, storage) and thermal (CCGT, CT) were tested. In addition to analyzing different outcomes for F.B. Culley 2 and F.B. Culley 3, A.B. Brown with and without the conversion of the new CTs to a CCGT conversion was considered.

With these various portfolios in mind, additional portfolios and iterations were developed based on 1) stakeholder feedback, 2) lessons learned from preliminary portfolio optimization results, 3) examining tradeoffs in different existing resource decision timing, and 4) continued right sizing portfolios on both capacity and energy. Once these diverse portfolios were created, they were run through the EnCompass model to be analyzed and screened.

8.1.3 Portfolio Screening

After the scenario based portfolios and alternatives were created, they were screened to maintain a reasonable number of portfolios to run through risk analysis. Three different categories were identified to screen out portfolios.

The first step in screening portfolios was to determine where there were portfolios with significant overlap in resource selection. The goal was to include portfolios in the risk analysis that were different enough to provide insights between different resource options. For example, the Reference Case, Market Driven Innovation, and Decarbonization/Electrification portfolios had similar resource selections (A.B. Brown CCGT Conversion in 2027, Retiring FB Culley 3 in 2029, and 200+ MW of Wind in early 2030s) to the Reference Case. Therefore, the Market Driven Innovation and Decarbonization/Electrification portfolios were removed from consideration because they did not provide any additional insights that could not be derived from the Reference Case portfolio.

Next, portfolios were screened based on their size compared to the needs of CEI South and their customers. The portfolio needed to meet seasonal capacity requirements while not significantly overbuilding generation, from either a capacity or energy basis. Several portfolios, which were hundreds of megawatts long on capacity and/or over generated energy compared to CEI South's need throughout study period, were screened out. The scenario-based portfolios High Regulatory and Continued High Inflation & Supply Chain Issues were screened out due to being overbuilt compared to CEI South's capacity needs. Certain resource mixes and portfolio concepts from these portfolios are included in deterministic portfolios at more right sized scale to CEI South's future needs.

The final screening category was cost. Portfolios which were significantly higher on cost when run through the reference case were removed along with portfolios which tested adding or replacing a specific resource that decreased portfolio performance were screened out. This included screening out portfolios that contained hydroelectric resources, which proved to be a very expensive option for CEI South customers. After screening out portfolios, there were 10 portfolios left to further evaluate in the risk analysis.

8.1.4 10 Portfolio Descriptions

The following sections describe in detail designed portfolios (including thermal, diverse and renewables-focused portfolios). Figure 8.2 Risk Analysis Portfolios shows a summary table of the build outs for each of the selected set of portfolios for consideration in the Risk Analysis.

Figure 8.2 – Risk Analysis Portfolios

Year	Reference Case	Business as Usual (BAU) Cont. FB Culley 3 on Coal	Convert F.B. Culley 3 to Natural Gas by 2030	Convert F.B. Culley 3 to Natural Gas by 2027	Convert F.B. Culley 3 to Natural Gas by 2027 with Wind and Solar
2023	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4
2024	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Continue FB Culley 3 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)
2027	CCGT Conversion			Covert FB Culley 3 to Natural Gas	Covert FB Culley 3 to Natural Gas Wind (200MW) Solar (200MW)
2028					
2029	Retire FB Culley 3	Storage (10MW)			
2030	Storage (10MW)	Wind (200MW)	Covert FB Culley 3 to Natural Gas Wind (200MW) Solar (200MW)	Wind (200MW) Solar (200MW)	
2032			Wind (200MW)	Wind (200MW)	Wind (200MW)
2033	Wind (400MW)		Wind (200MW)	Wind (200MW)	Wind (200MW)
2041					
2042	Storage (10MW)	Storage (10MW)			

Year	CT Portfolio (Replace FB Culley 3 with F Class CT)	Diversified Renewables	Diversified Renewables (Early Storage & DG Solar)	Replace FB Culley 3 with Storage and Wind	Replace FB Culley 3 with Storage and Solar
2023	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4
2024	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)
2027			Solar (60MW)		
2028			Storage (90MW)		
2029	Retire FB Culley 3	Retire FB Culley 3 Wind (200MW)	Retire FB Culley 3	Retire FB Culley 3	Retire FB Culley 3
2030	F-Class CT Storage (60MW)	Storage (200MW) Solar (200MW) Wind (200MW)	Storage (100MW) Wind (400MW) Solar (100MW)	Storage (300MW) Wind (400MW)	Storage (250MW)
2033	Wind (600 MW)	Wind (200MW)	Wind (200MW)	Wind (200MW)	Solar (300MW)
2041			Solar (100MW)		
2042			Solar (100MW)		Storage (10MW)

8.1.4.1 Reference Case

The Reference Case portfolio was built based on the Reference Case ("most likely" future), built with commodity forecasts based on a consensus outlook from industry experts as described in Section 7.2 Reference Case Scenario. This least cost portfolio converts CEI South's two new CTs to a CCGT in 2027 and retires F. B. Culley 3 by the end of 2029. It also includes a significant amount of renewable resources. More capacity was selected within the model than what was needed until F.B. Culley 3 is retired in 2029 and then is generally in line with CEI South's capacity need in the long term as shown in Figures 8.3 and 8.4. On an energy basis, this portfolio generates much more energy than is needed for CEI South customers, as shown in Figure 8.5.

Figure 8.3 – Reference Case Summer Capacity

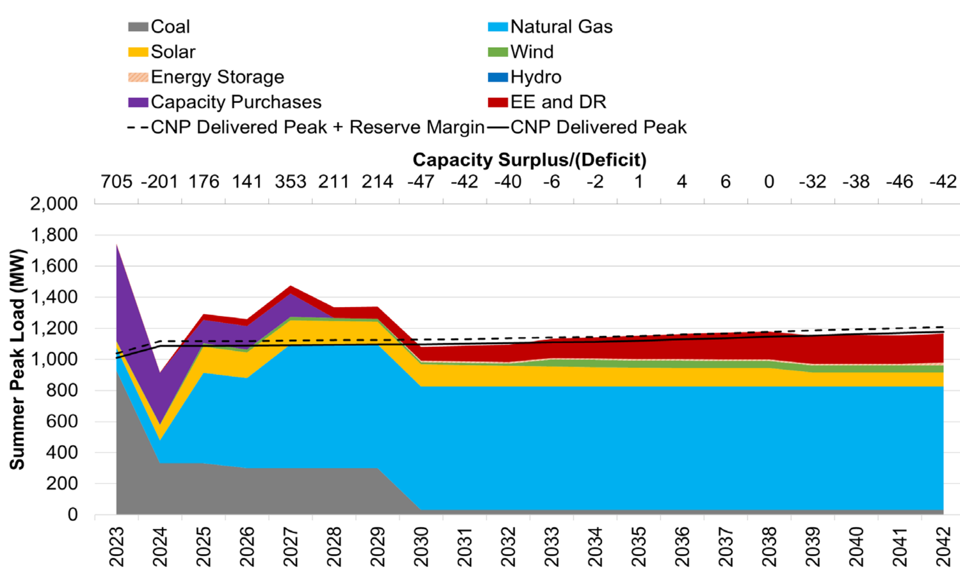


Figure 8.4 – Reference Case Winter Capacity

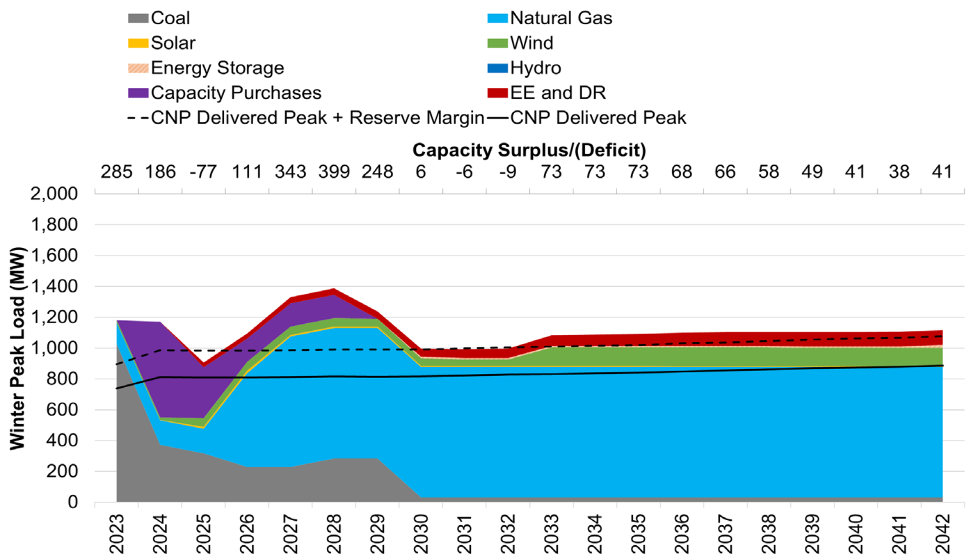
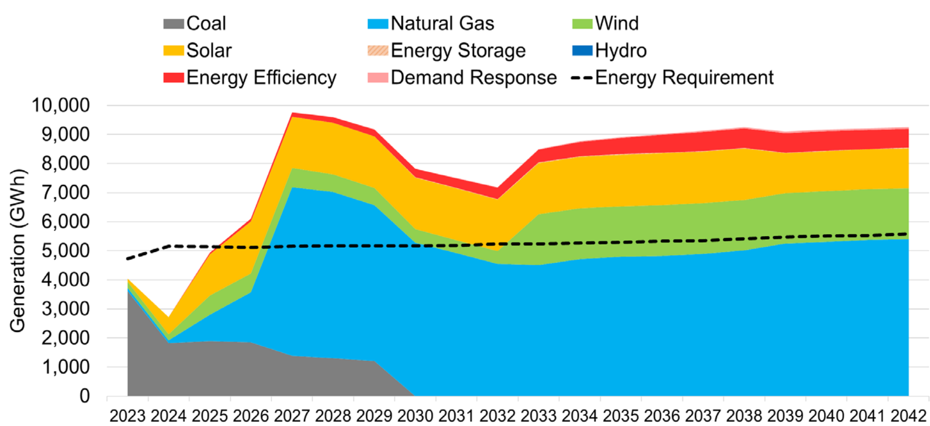


Figure 8.5 – Reference Case Energy (Reference Case Conditions)



8.1.4.2 Business as Usual ("BAU") Continue F.B. Culley 3 on Coal

The BAU portfolio was designed, by definition, to provide a business as usual outlook through the forecast period. In this portfolio, F B Culley 2 is retired in 2025, and F B Culley 3 is kept in operation throughout the study period. This portfolio provides a useful, status quo benchmark for financial and operational performance to compare against all the other candidate portfolios. This portfolio required a small amount of energy storage and added

200 MWs of wind in 2030 to meet capacity and energy requirements. As shown in Figures 8.6-8.8, this portfolio balances the need for energy and capacity well throughout the study period.

Figure 8.6 – BAU Summer Capacity

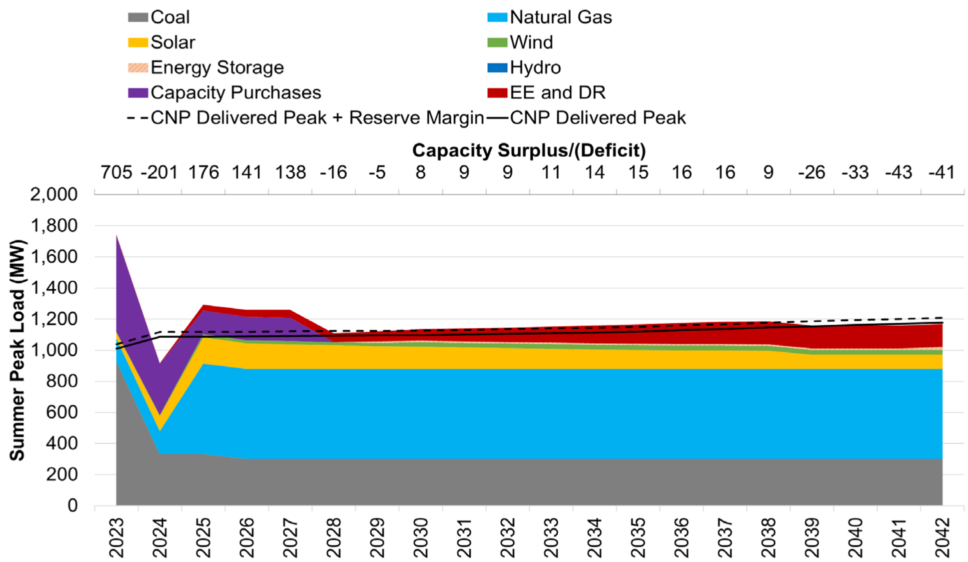


Figure 8.7 – BAU Winter Capacity

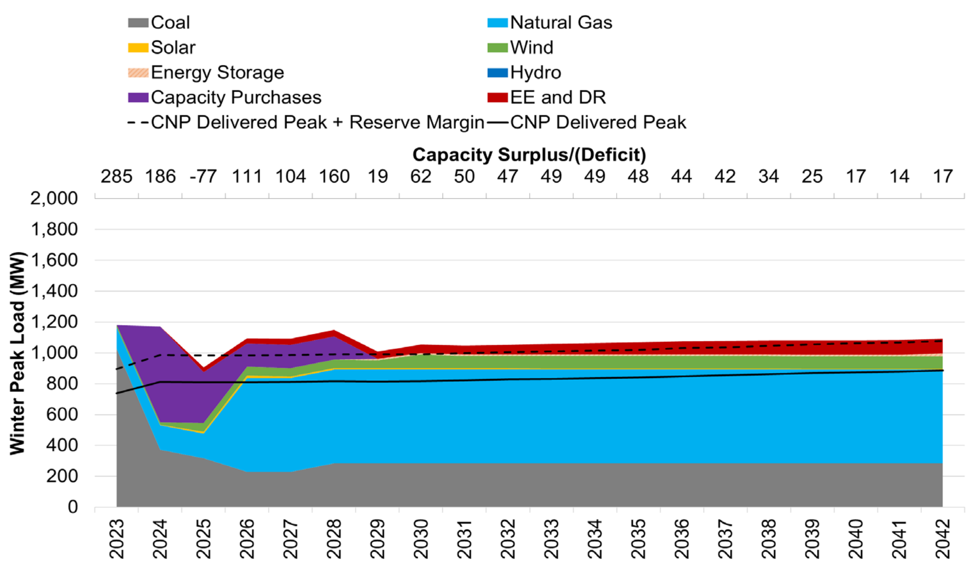
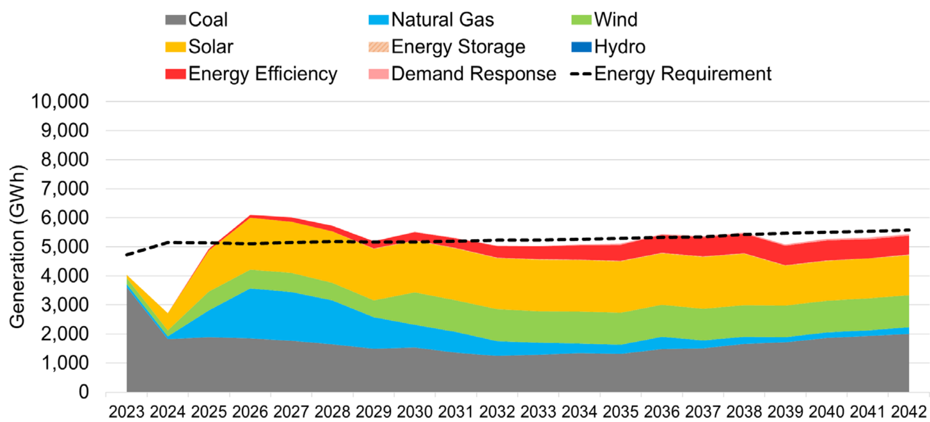


Figure 8.8 – BAU Energy (Reference Case Conditions)



8.1.4.3 Convert F B Culley 3 to Natural Gas by 2030

This portfolio was designed to include the conversion of F B Culley 3 from a baseload coal-fired to natural gas peaking plant, which helps to preserve and repurpose much of the existing asset base. The unit would be converted for operation beginning in 2030 through the end of the study period. This balanced portfolio includes 200 MW of wind and 200 MW of solar in 2030 with two additional 200 MW of blocks of wind in 2032 and 2033, respectively. As shown in Figures 8.9-8.11, this portfolio balances the need for energy and capacity well throughout the study period.

Figure 8.9 – Convert F.B. Culley 3 to Natural Gas by 2030 Summer Capacity

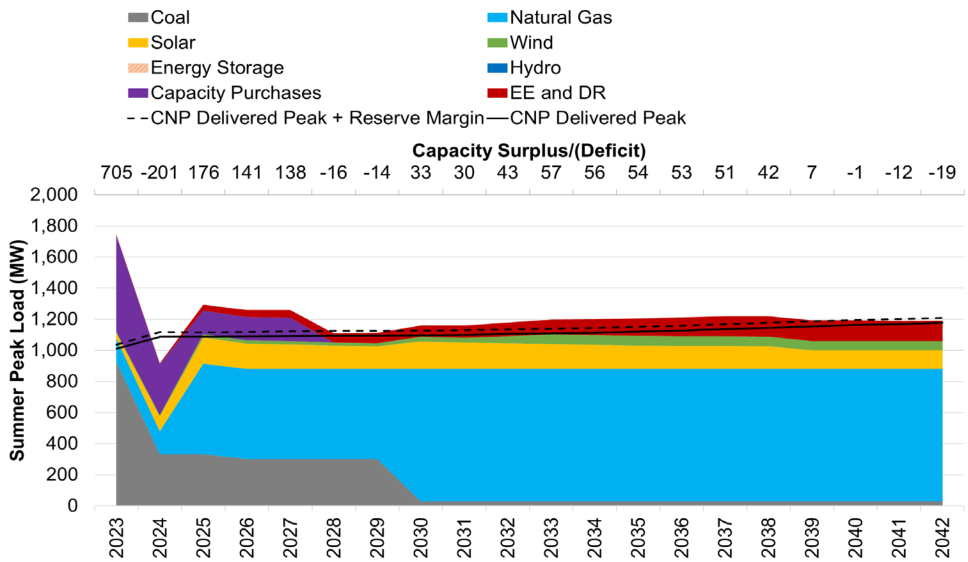


Figure 8.10 – Convert F.B. Culley 3 to Natural Gas by 2030 Winter Capacity

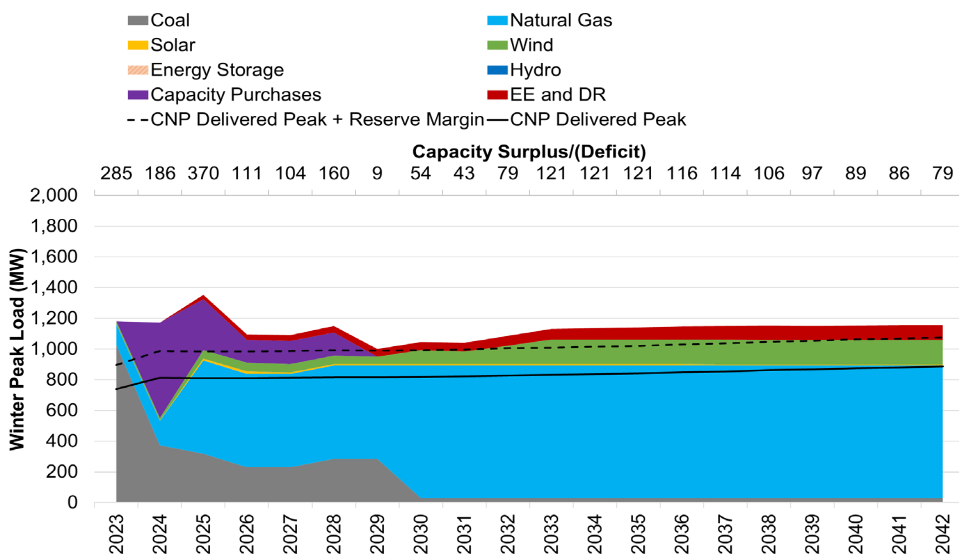
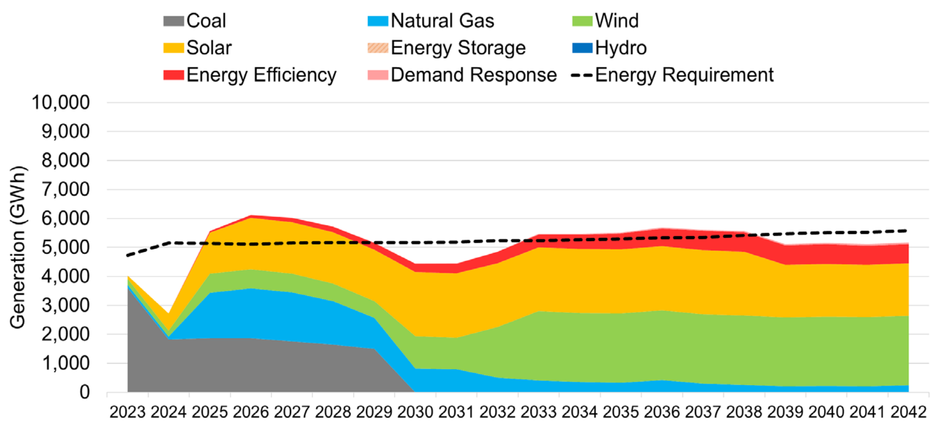


Figure 8.11 – Convert F.B. Culley 3 to Natural Gas by 2030 Energy (Reference Case Conditions)



8.1.4.3.1 Convert F.B. Culley 3 to Natural Gas by 2027

This portfolio was designed to include the conversion of F B Culley 3 from baseload coal-fired to a natural gas peaking plant by 2027 to explore tradeoffs with potential conversion in 2030. All other resources remain the same as the Convert F.B. Culley 3 to Natural Gas by 2030. As mentioned above, the conversion helps to preserve and repurpose much of the existing asset base at this facility. As shown in Figures 8.12-8.13, this portfolio meets capacity obligations well throughout the study period. There is a near to mid-term reliance on the energy market; however, this portfolio contains a high level of dispatchable generation that can help shield customers from high energy prices.

Figure 8.12 – Convert F.B. Culley 3 to Natural Gas by 2027 Summer Capacity

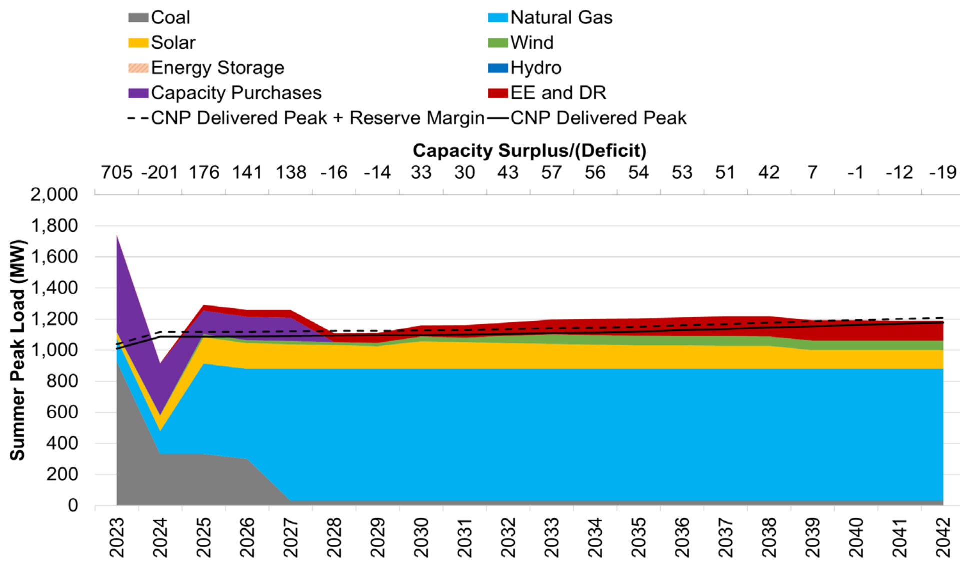


Figure 8.13 – Convert F.B. Culley 3 to Natural Gas by 2027 Winter Capacity

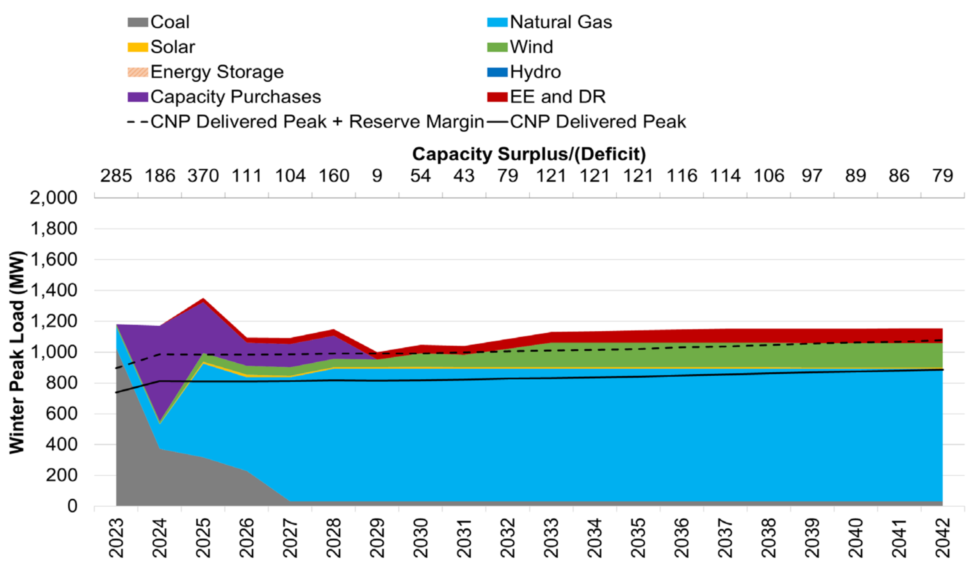
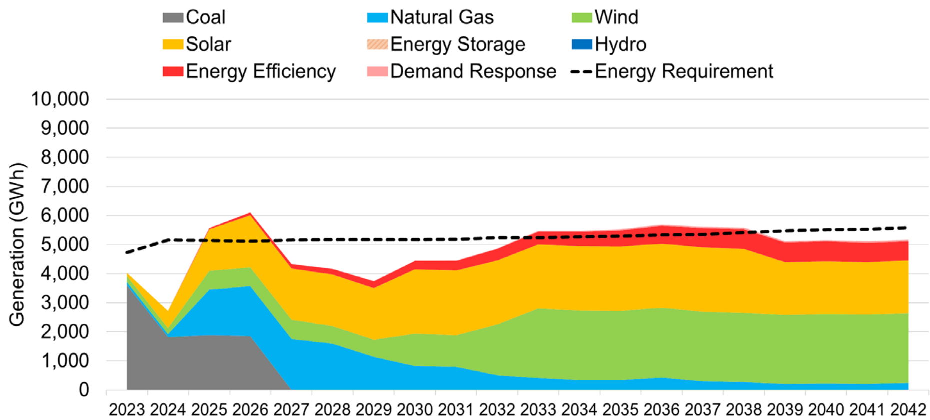


Figure 8.14 – Convert F.B. Culley 3 to Natural Gas by 2027 Energy (Reference Case Conditions)



8.1.4.3.2 Convert F B Culley 3 to Natural Gas by 2027 with Wind and Solar

Like the portfolio before it, this portfolio was designed to include the conversion of F.B. Culley 3 from baseload coal-fired to a natural gas peaking plant by 2027. It pulls forward 200 MWs of solar and 200 MWs of wind from 2030 to 2027 to explore the tradeoff associated with reliance on the market in the near term versus acquiring these renewable resources earlier. All other resources remain the same. As shown in Figures 8.15-8.17, this portfolio meets capacity obligations well throughout the study period.

Figure 8.15 – Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 Wind and Solar Summer Capacity

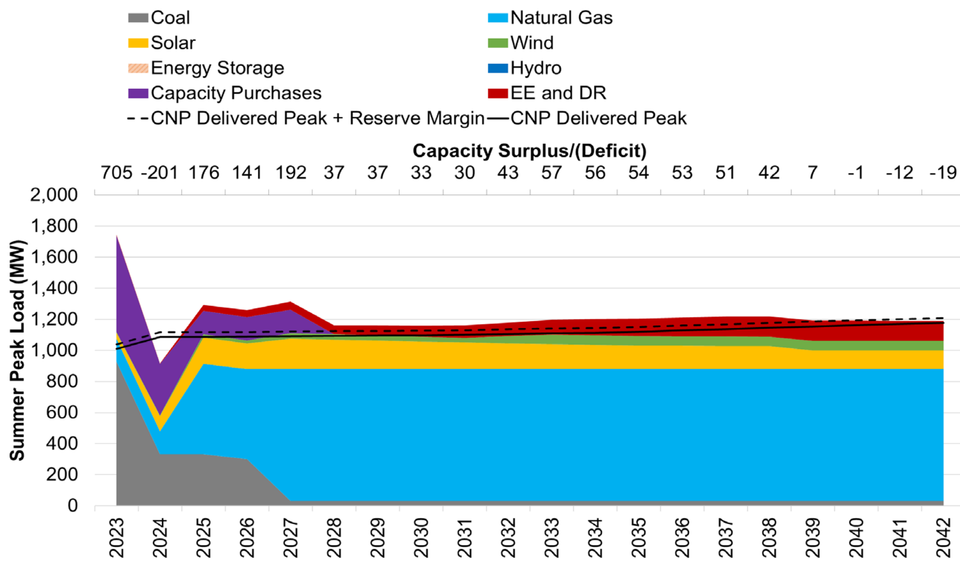


Figure 8.16 – Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 Wind and Solar Winter Capacity

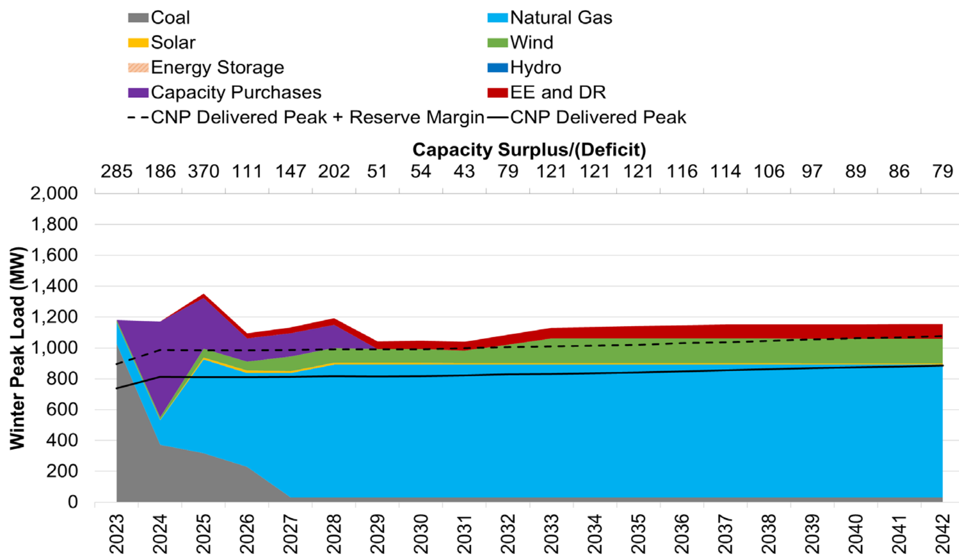
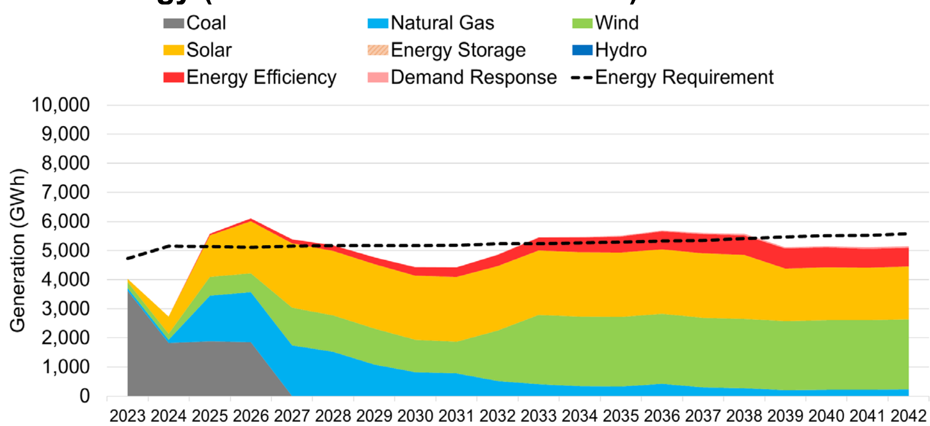


Figure 8.17 – Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 Wind and Solar Energy (Reference Case Conditions)



8.1.4.3.3 CT Portfolio (Replace F B Culley 3 with F-Class CT)

The CT Portfolio was included to evaluate the replacement of F.B. Culley 3 with a new approximately 230 MW F-Class Combustion Turbine. This portfolio strategy provides a transition pathway to a generation fleet without operating coal, while maintaining and adding a diverse fuel mix of generation technologies, which include a 60 MW battery in 2030 and 600 MWs of wind in 2033. As shown in Figures 8.18-8.20, this portfolio meets capacity obligations well throughout the study period. There is a near to mid-term reliance on the energy market; however, this portfolio contains a high level of dispatchable generation that can help shield customers from high energy prices. The F-class CTs in this portfolio can start fast and ramp quickly.

Figure 8.18 – CT Portfolio (Replace F B Culley 3 with F-Class CT) Summer Capacity

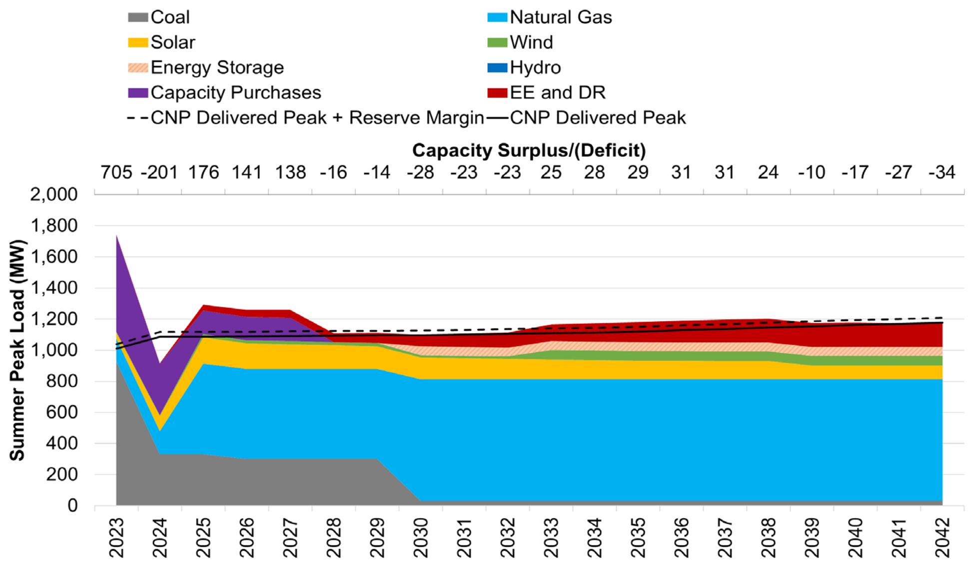


Figure 8.19 –CT Portfolio (Replace F B Culley 3 with F-Class CT) Winter Capacity

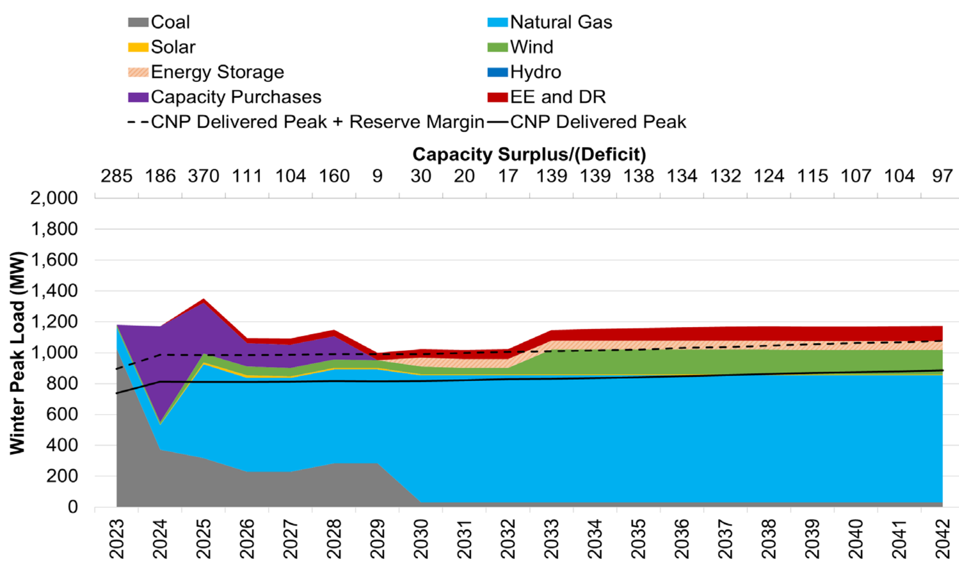
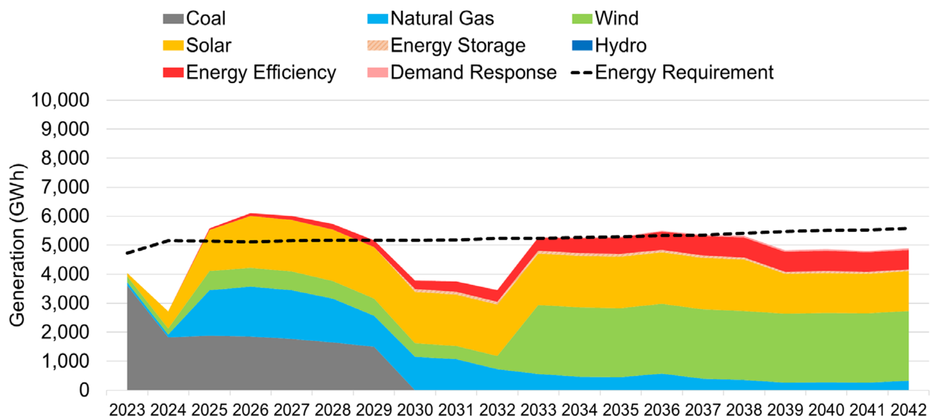


Figure 8.20 –CT Portfolio (Replace F B Culley 3 with F-Class CT) Energy



8.1.4.3.4 Diversified Renewables

The Diversified Renewables portfolio was designed to transition CEI South's new generation additions to 100% renewables and battery storage beginning in 2030. To meet capacity and energy obligations when F.B. Culley 3 retires in 2029, the portfolio includes a large amount of storage, wind and solar, as shown in Figures 8-20 to 8-23. 200 MWs of wind comes in 2029, followed by 200 MWs of storage, 200 MWs of solar, and 200 MWs of additional wind in 2030. By 2033 another 200 MW wind resource is acquired. As described in Section 6.4.3 this portfolio, a portfolio with a large battery at the F.B. Culley Power Plant site would require system upgrades to support charging.

Figure 8.21– Diversified Renewables Summer Capacity

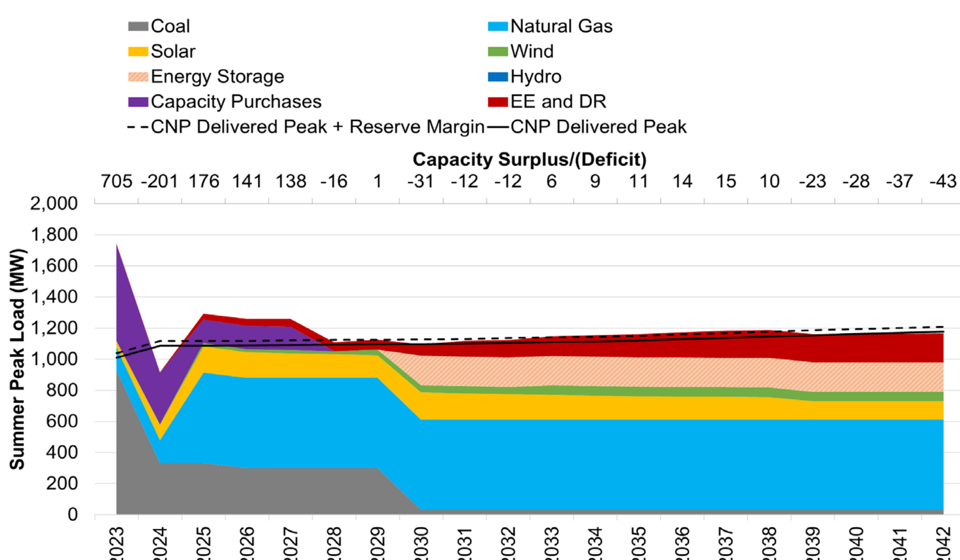


Figure 8.22– Diversified Renewables Winter Capacity

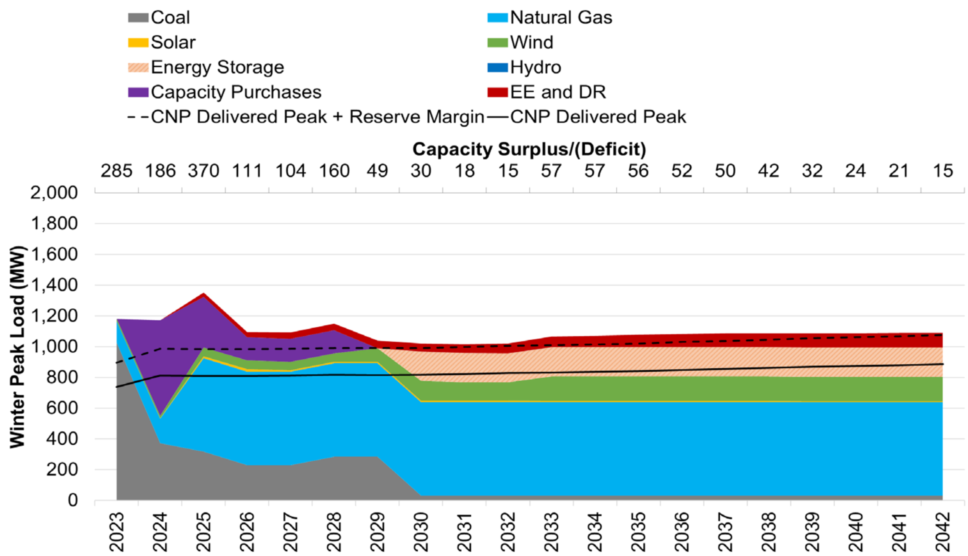
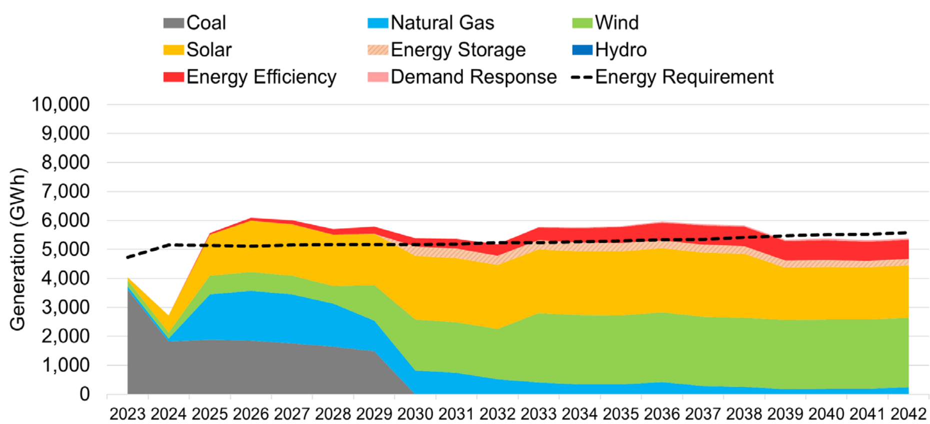


Figure 8.23– Diversified Renewables Energy



8.1.4.3.5 Diversified Renewables (Early Storage & DG Solar)

The Diversified Renewables (Early Storage & DG Solar) portfolio was designed to transition CEI South's generation fleet to renewables and battery storage by adding early storage and distributed generation from solar. The early storage is meant to replace F.B. Culley 2, preserving the interconnection rights at that site. Additionally, it includes distributed solar resources early in the planning period. Beyond that, this portfolio includes an additional 100 MW battery, 400 MWs of wind, and 100 MWs of solar to replace F.B. Culley 3, which closes in 2029. The portfolio also includes more renewable resources in 2033-2042. The portfolio meets capacity and energy obligations, as shown in Figures 8.24-8.26.

Figure 8.24– Diversified Renewables (Early Storage & DG) Summer Capacity

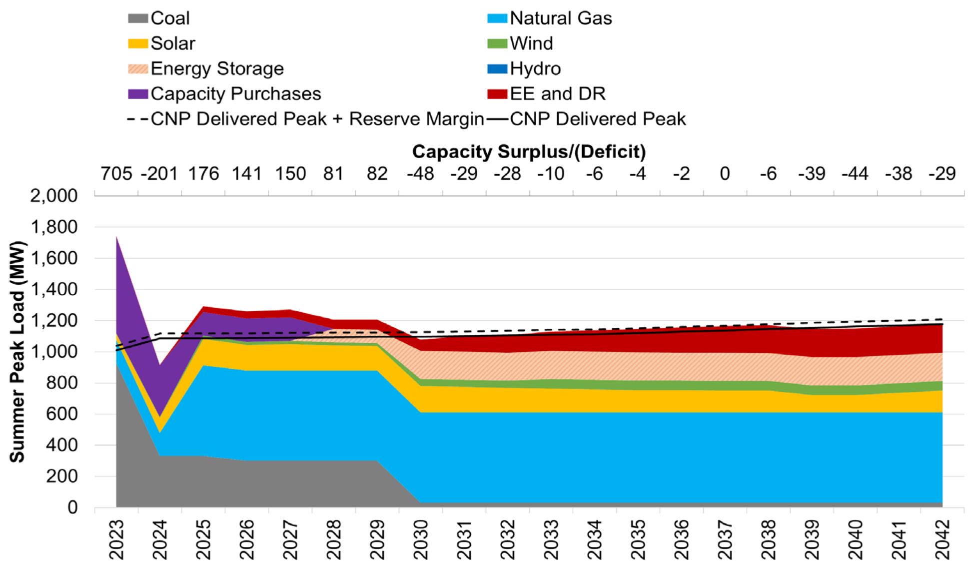


Figure 8.25– Diversified Renewables (Early Storage & DG) Winter Capacity

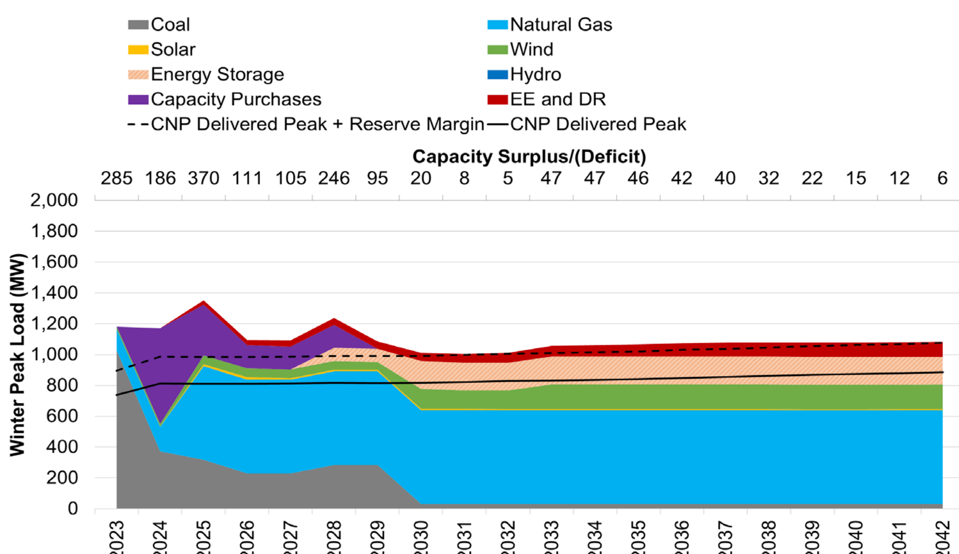
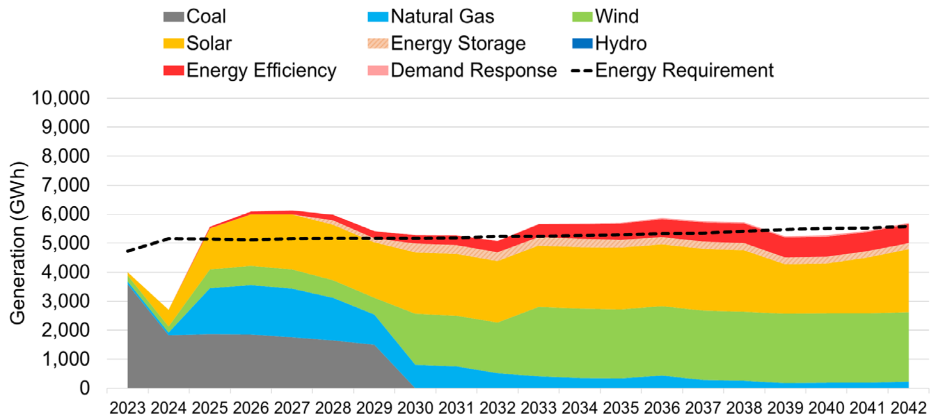


Figure 8.26– Diversified Renewables (Early Storage & DG) Energy



8.1.4.3.6 Replace F B Culley 3 with Storage and Wind

The Replace F B Culley 3 with Storage and Wind portfolio retires F.B. Culley 3 in 2029 and replaces it with 300 MWs of storage and 400 MWs of wind in 2030. Additionally, 200 MWs of additional wind is included within this portfolio in 2033. The portfolio does a good job of meeting both capacity and energy requirements as shown in Figures 8.27 – 8.29.

Figure 8.27– Replace F B Culley 3 with Storage and Wind Summer Capacity

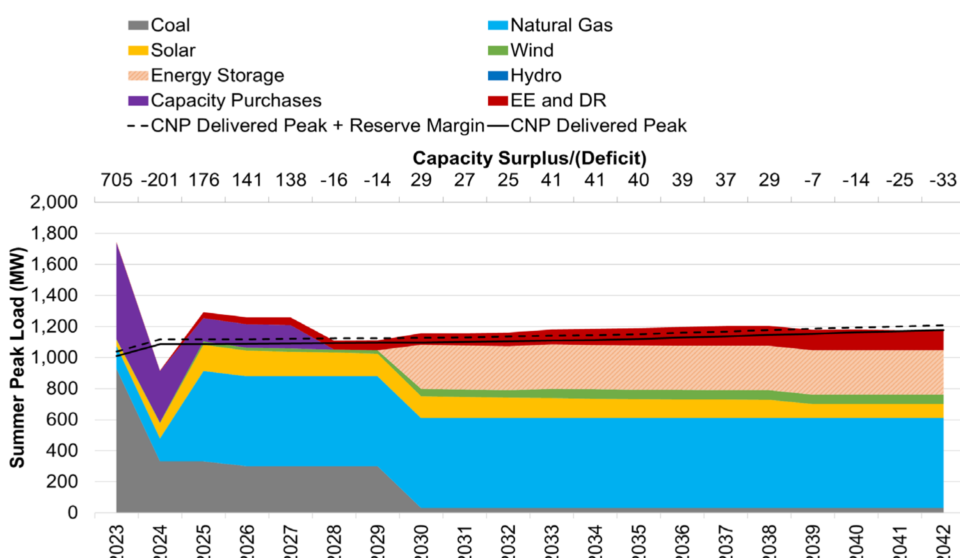


Figure 8.28– Replace F B Culley 3 with Storage and Wind Winter Capacity

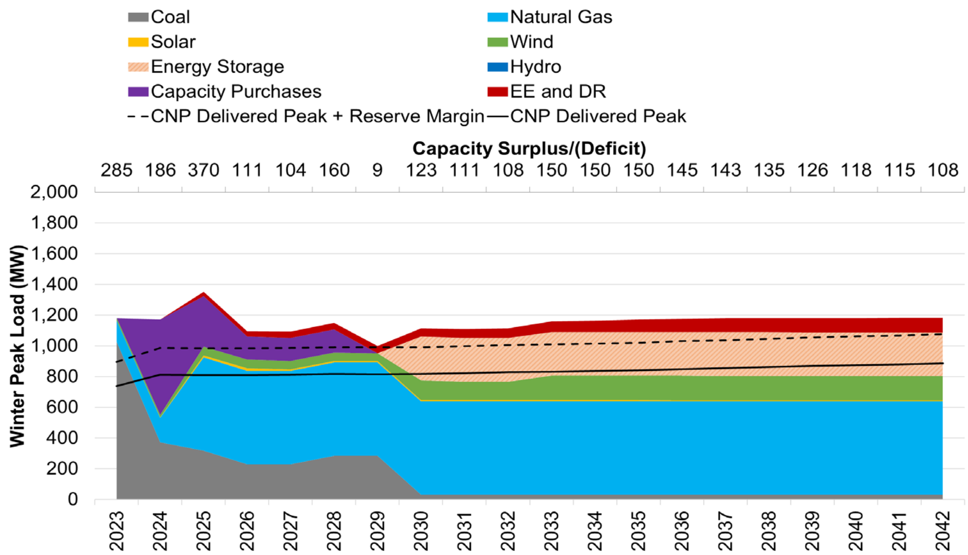
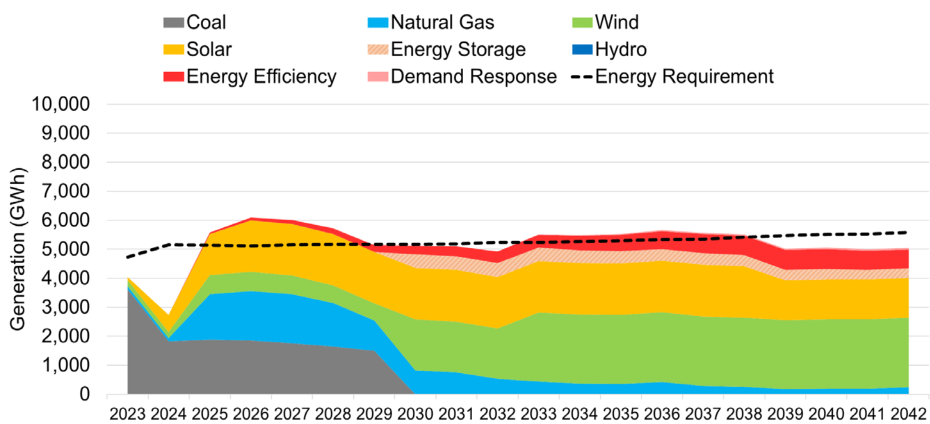


Figure 8.29– Replace F B Culley 3 with Storage and Wind Energy



8.1.4.3.7 Replace F B Culley 3 with Storage and Solar

The Replace F B Culley 3 with Storage and Solar portfolio retires F.B. Culley 3 in 2029 and replaces it with 250 MWs of storage in 2030 includes 300 MWs of solar in 2033. This portfolio meets capacity obligations over time; however, it is heavily reliant on the market for energy over the remainder of the planning period once F.B. Culley 3 is replaced, as shown in Figure 8.32.

Figure 8.30– Replace F B Culley 3 with Storage and Solar Summer Capacity

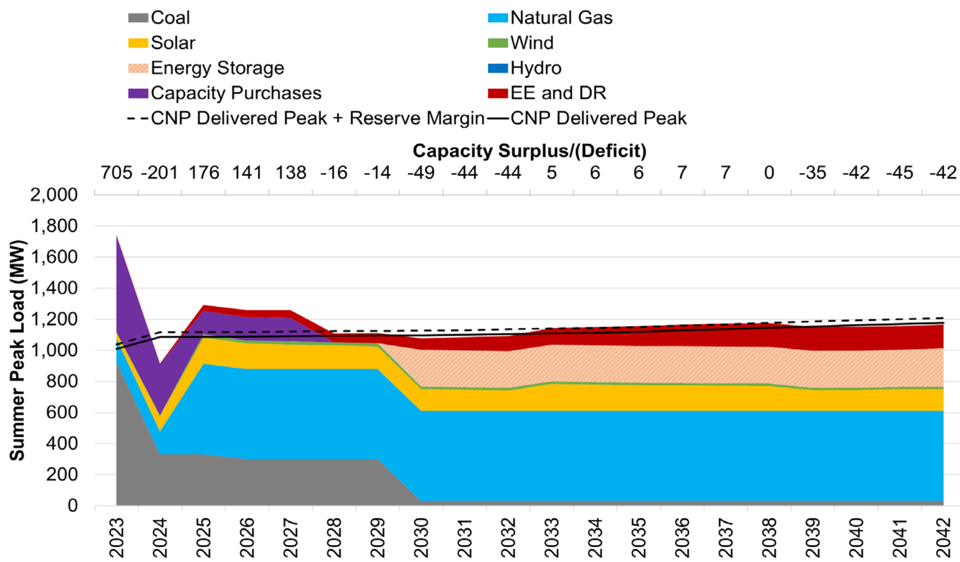


Figure 8.31– Replace F B Culley 3 with Storage and Solar Winter Capacity

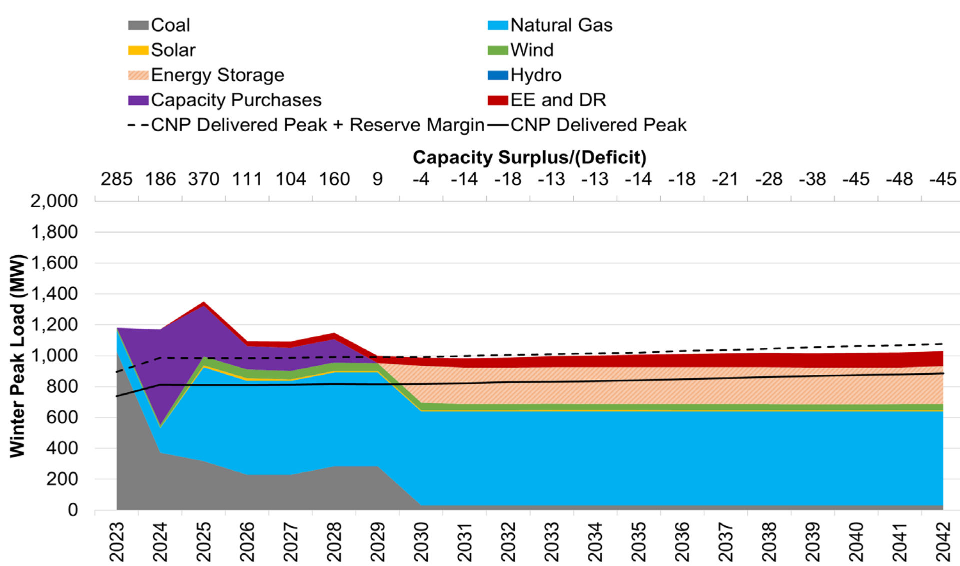
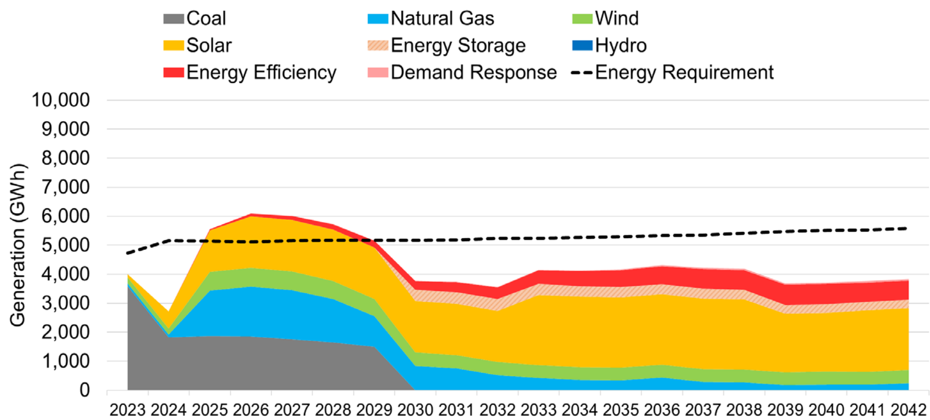


Figure 8.32– Replace F B Culley 3 with Storage and Solar Energy



8.2 EVALUATION OF PORTFOLIO PERFORMANCE

Each of the risk analysis candidate portfolios were subjected to two different forms of risk analysis. One was scenario-based, and one was based on probabilistic modeling (200 iterations), which serves as the basis for the balanced scorecard.

8.2.1 Scenario Risk Analysis

The IRP requires scenario-based modeling be performed as a part of the risk analysis. In the scenario-based risk analysis, the remaining ten candidate portfolios that were selected for further analysis were modeled under each of the five scenarios with their respective market inputs. The following provides a summary of the results of this scenario-based risk analysis. The results shown in Figures 8-33 – 8.34 are the net present value revenue requirement ("NPVRR") and the carbon production throughout the study period in each scenario. The preferred portfolio performed well across all potential futures. Natural gas forecast in the High Regulatory and the Inflation and Supply Chain Issues Scenarios increase by an average of 78% and 29% respectively. This could signal that a natural gas conversion would not be economic. Under the conversion to peaking generation, the unit operates roughly 1% of the time, which greatly improves the carbon output of the portfolio and limits exposure to these costs. The renewable buildout of the portfolio also helps to shield customers from this cost risk by providing the vast amount of energy needed to support customer loads.

Figure 8-33 – Portfolio NPVRR (million $)

Portfolio	Reference	Market Driven Innovation	Decarbonization/ Electrification	High Regulatory	Inflation and Supply Chain Issues
Reference Case	$4,120	$3,923	$4,391	$4,938	$4,327
Replace FB Culley 3 with Storage and Solar	$4,277	$4,104	$5,038	$5,930	$4,701
F-Class CT	$4,321	$4,099	$4,924	$5,624	$4,609
Convert F.B. Culley 3 to Natural Gas by 2030	$4,331	$4,128	$4,850	$5,461	$4,616
Business as Usual	$4,325	$4,190	$5,146	$6,011	$4,428
Convert F.B. Culley 3 to Natural Gas by 2027	$4,341	$4,120	$4,834	$5,452	$4,646
Diversified Renewables	$4,390	$4,248	$4,876	$5,453	$4,831
Replace FB Culley 3 with Storage and Wind	$4,370	$4,251	$4,929	$5,596	$4,862
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	$4,437	$4,206	$4,883	$5,405	$4,660
Diversified Renewables (Early Storage & DG Solar)	$4,485	$4,331	$4,978	$5,552	$4,939

Figure 8-34 – Portfolio Total CO_2 Emissions Throughout the Study Period

CO2 (Tons)	Reference	Market Driven Innovation	Decarbonization/ Electrification	High Regulatory	Inflation and Supply Chain Issues
Reference Case	43,998,248	45,249,902	39,885,693	31,425,636	41,209,220
Replace FB Culley 3 with Storage and Solar	20,815,471	23,978,288	15,126,039	9,113,029	19,338,865
F-Class CT	21,883,367	26,519,310	16,845,029	9,913,288	19,942,549
Convert F.B. Culley 3 to Natural Gas by 2030	20,915,819	23,654,435	15,288,780	9,447,350	19,386,506
Business as Usual	40,987,565	29,503,845	15,682,713	15,289,387	41,614,200
Convert F.B. Culley 3 to Natural Gas by 2027	16,111,764	21,216,414	15,234,745	8,253,657	14,006,533
Diversified Renewables	20,783,694	23,642,166	15,000,146	9,084,486	19,309,689
Replace FB Culley 3 with Storage and Wind	20,852,703	23,982,021	15,133,020	9,136,079	19,343,788
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	16,041,055	21,148,848	15,117,504	8,220,479	13,922,764
Diversified Renewables (Early Storage & DG Solar)	20,742,008	23,729,672	15,068,589	9,077,265	19,284,001

8.2.2 Sensitivity Analysis

Several sensitivities were conducted on the candidate portfolios to test and refine the design of the portfolios and whether and how results might change if isolated variables might change. The following section describes these sensitivities and the conclusions drawn from this analysis, as well as any impact on the candidate portfolios.

The All-Source RFP resulted in several solar, wind and battery storage resources that were included as near-term resources in the optimization module of the EnCompass model. Storage resources have experienced price volatility due to the impacts of the Inflation Reduction Act on investment tax credits. If CEI South is unable to fully monetize the tax credit, the credits may be sold to the market, or to other third party options resulting in less than the full amount of the investment tax credit. A sensitivity was performed in which storage options received 85% of the full investment tax credit. The decrease in storage tax credit monetization only impacts portfolios that included storage, and these portfolios NPV's saw less than a 1% increase in NPV due to the adjusted ITC, around a .1% increase per 100 MW of storage included in the portfolio.

A sensitivity was performed to test the impact of increases in wind cost on portfolio NPV and resource decisions. Based on this analysis, if wind costs were to increase, alternate resources, such as solar or storage resources, would be selected to meet planning reserves with little to no NPV impact on the portfolio.

Given the potential changes in the New Source Performance Standard 111B, nearly half (80 out of 200) of the probabilistic risk analysis simulations included a carbon tax. The introduction of a carbon tax as a proxy for potential change in legislation helps quantify the magnitude of the impact portfolios would be exposed to under more stringent emission regulations. From this sensitivity each of the 10 portfolios saw a 16% to 26% increase in NPV. Both the portfolios including the conversion of F.B. Culley 3 to natural gas and portfolios with high renewable dependency experienced less cost risk than the portfolio that continues operation of F.B. Culley 3 on coal.

A sensitivity was run on the impact of a lower capacity accreditation for battery storage over the study period. The base battery storage accreditation included in the modeling was 95% throughout the study period. It is expected that with MISO's shift to a seasonal construct and reviewing of renewable and storage accreditation methodology, there is potential that battery accreditation will decrease in the future. For modeling of this sensitivity, a declining capacity accreditation was applied. The updated capacity accreditation starts at 100% in 2023 and decreases from 2028 until 2037 to 75% where it remains for the rest of the study period. These annual battery storage capacity accreditation values were utilized by MISO in their MISO Futures Report LRTP Tranche 2 Refresh[69]. When the capacity accreditation is updated from 95% to the declining curve, portfolios which include storage are more reliant on market capacity purchases or would need to procure additional resources to meet CEI South's capacity needs. The reduction of capacity accreditation in the out years from 95% to 75% results in increased portfolio costs of up to 2.9%. Future seasonal capacity accreditations for 4-hour storage are difficult to quantify in MISO, but as more storage is added to the system it is expected to decline. In some regions of the US storage capacity accreditation is projected to decline even further than the 75% accreditation used in this sensitivity.

To simulate a possible increase in customer demand a final sensitivity was conducted to evaluate the impacts of a large industrial customer coming online in 2028. 300 MW of additional load was added to the Reference Case load forecast in 2028 and remains online throughout the study period. The model was allowed to optimize unconstrained to compare project selections given this load addition. To meet this demand AB Brown 5 and AB Brown 6 were converted from existing CTs to a CCGT and an additional J-Class CT was added.

[69] MISO; LRTP Tranche 2 – Futures Refresh Assumptions Book; Last Updated April 27, 2023 https://cdn.misoenergy.org/20230308%20PAC%20Item%2008a%20Futures%20Refresh%20Assumptions%20Book628109.pdf

8.2.3 STOCHASTIC (PROBABILISTIC) RISK ASSESSMENT

After selecting the 10 portfolios for further consideration and completion of the deterministic (Scenario based) risk assessment and sensitivities, the remaining step is to conduct the 200 iteration or scenario risk assessment and complete the balanced scorecard, consider "other" relevant factors and select the preferred portfolio given this information.

A more comprehensive risk analysis, using 200 iterations or scenarios, was utilized to provide a more comprehensive assessment of how the 10 portfolios performed under a range of conditions. As with any analysis, the risk analysis and the balanced scorecard that is developed from it, does not provide CEI South with an answer, but rather it is intended to provide insights into tradeoffs associated with a variety of portfolios over a range of future conditions.

The relevant information is provided in many of the metrics in the balanced scorecard. The benefit of conducting the stochastic risk assessment is that CEI South can get a clearer picture of the tradeoffs between least cost, the cost uncertainty (measured by the 95th percentile of cost outcomes over the planning horizon), the carbon equivalent profile of the portfolios and the percentage dependence on energy and capacity purchases and sales of the portfolios based on the probabilistic range of potential outcomes. After this comparison there is also a discussion of other factors that must be considered, like diversity, flexibility, and optionality to adapt to conditions that might cause uneconomic assets.

A summary of how the ten candidate portfolios performed against each of the above metrics is provided in the table below:

Figure 8-35 – IRP Portfolio Balanced Scorecard Color-Coded Comparison

Scorecard - Ranked	Affordability / Cost Risk			Environmental Sustainability		Reliability				Market Risk Minimization							
Portfolio	20 Year NPVRR ($M)	Delta From Reference (%)	Proportion of Energy Generated by Resources With Exposure to Coal and Gas Markets and Market Purchases (%)[1]	95% Value of NPVRR ($)	CO2 Intensity (Tons CO_2/kwh)[2]	CO2 Equivalent Emissions (Stack Emissions) (Tons CO_2)[3]	Must Meet MISO Planning Reserve Margin Requirement in All Seasons (MW)[4] Summer	Must Meet MISO Planning Reserve Margin Requirement in All Seasons (MW)[4] Winter	Fast Start Capability (MW)[5]	Dispatchable Resource with Spinning Reserve Capability (MW)[6]	Energy Market Purchases[7] Average	Energy Market Purchases[7] Near Term Max	Energy Market Purchases[7] Long Term Max	Energy Market Sales[7] Average	Energy Market Sales[7] Near Term Max	Energy Market Sales[7] Long Term Max	Capacity Market Purchases or Sales (%)[8] Purchases	Capacity Market Purchases or Sales (%)[8] Sales
Reference Case	$4,214	0.0%	56%	$4,952	0.00024	33,199,947	97	62	11	919	12%	24%	18%	33%	42%	41%	1.2%	12%
F-Class CT	$4,499	6.7%	30%	$5,413	0.00018	17,975,167	80	22	758	900	28%	40%	46%	17%	21%	24%	0.8%	11%
Convert F.B. Culley 3 to Natural Gas by 2027	$4,503	6.8%	27%	$5,316	0.00015	15,506,174	60	21	469	941	26%	39%	32%	19%	22%	27%	0.6%	12%
Convert F.B. Culley 3 to Natural Gas by 2030	$4,508	7.0%	27%	$5,332	0.00016	16,953,911	60	21	469	941	25%	35%	32%	19%	22%	27%	0.6%	12%
Replace FB Culley 3 with Storage and Solar	$4,539	7.7%	29%	$5,416	0.00018	15,917,099	101	137	720	671	38%	43%	49%	13%	21%	17%	1.7%	8%
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	$4,559	8.2%	25%	$5,347	0.00014	15,382,405	60	21	469	941	24%	31%	32%	20%	24%	27%	0.6%	13%
Replace FB Culley 3 with Storage and Wind	$4,580	8.7%	26%	$5,328	0.00015	15,931,427	74	9	769	671	27%	35%	33%	15%	21%	21%	0.7%	12%
Business as Usual	$4,581	8.7%	35%	$5,486	0.00025	23,897,336	90	74	480	941	31%	35%	36%	14%	21%	19%	0.9%	10%
Diversified Renewables	$4,583	8.8%	25%	$5,313	0.00015	15,763,426	89	71	669	671	25%	31%	30%	18%	22%	24%	1.1%	9%
Diversified Renewables (Early Storage & DG Solar)	$4,676	11.0%	25%	$5,408	0.00015	15,766,880	94	81	659	671	25%	34%	30%	18%	22%	24%	1.2%	9%

1: Total energy generation from coal and gas / total fleet generation from 2023 - 2042
2: Average CO_2e from generation / average fleet generation from 2030 - 2042
CO_2e shown in metric tons
3: Sum of CO_2e emissions from 2023 - 2042
4: Maximum seasonal capacity deficit in summer/winter from 2030 - 2042
5: Average MW of installed battery, CT, recip capacity from 2030 - 2042
6: Average MW of dispatchable resources from 2030 - 2042
7: Average GWh energy market interaction / total energy + sales from 2023 - 2042
Near Term: 2026 - 2030
Long Term: 2031 - 2042
8: Average capacity market purchases / coincident peak demand from 2023 - 2042

A color-coded comparison (conducted automatically by the spreadsheet) of the balanced scorecard is shown above in Figure 8-35. Green indicates scoring well relative to other portfolios within the same metric and red indicates scoring poorly relative to other portfolios within the same metric. The color scheme is purely for illustrative purposes to show where differences between the best performing portfolio and the worst performing for that metric is displayed. For more information on this analysis, please see the final stakeholder presentation in Technical Appendix 3.

SECTION 9
IRP PREFERRED PORTFOLIO

9.1 PREFERRED PORTFOLIO RECOMMENDATION

Based upon several factors, CEI South's preferred portfolio is the convert F.B. Culley 3 by 2027 portfolio.

9.1.1 Description of the Preferred Portfolio

The new and existing supply and demand resources in the preferred portfolio includes conversion of F.B. Culley 3 (270 MW) to natural gas by 2027, 200 MW of wind resources and 200 MW of solar by 2030, and an additional 400 MWs of wind generation between 2031 and 2032. These supply side resources are complemented by demand side resources, demand response and energy efficiency. Approximately 1.1% of energy efficiency was selected in the near-term time period (2025-2027) across three sector (commercial, residential, income-qualified) categories with residential further grouped by low to high cost bundles. The second vintage period (2028-2030) selected approximately 1.2% of energy efficiency bundles and approximately 1.1% of energy efficiency bundles are selected in the long-term (2031-2042). In addition, low Income energy efficiency is included in all periods. The optional demand response bin is selected in the time periods 2028-2030 and 2031-2042, while a DLC program called Summer Cycler is transitioned to Wi-Fi thermostats over time.

The preferred portfolio (Convert F.B. Culley 3 by 2027) performs well across a range of metrics, both in absolute terms and relative to the other candidate portfolios. The preferred portfolio was within 7 percent of the lowest cost portfolio and a tenth of a percent from the next lowest option. It ranks 3 out of 10 (third best) in the 95th percentile cost risk metric. It does not over-rely on either purchases or sales of energy or capacity. The preferred portfolio maintains 270 MWs of low cost, dispatchable capacity to support CEI South customers during the worst weeks of each season providing a physical hedge against high energy prices during peak periods.

Importantly it provides the flexibility and optionality in the future MISO system adapts to higher levels of renewables across the system, allowing more time for other technologies, like long duration battery storage, to be commercialized. By having the option to retire F.B. Culley 3 provides CEI South on offramp in the future to move when needed to a portfolio with less reliance on fossil resources.

The preferred portfolio is among the best performing portfolios across multiple measures on the balanced scorecard and provides a number of additional benefits to CEI South customers and other stakeholders, including that it:

- Eliminates dependence on coal-fired generation in a prompt timeframe, allowing 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.
- 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. The preferred portfolio is among the lowest cost portfolios.
- 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); protects against overreliance on the market for energy and capacity.
- Maintains future flexibility with several off ramps to accommodate a rapidly evolving industry and includes a multi-year build out of resources on several sites, maintaining the option to replace of Culley 3 in the future when appropriate based on continual evaluation of changing technology and conditions.
- 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 future potential 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.

9.1.2 Affordability

Affordability is a key objective in the balanced scorecard and that is measured as part of the stochastic analysis. The measure for affordability is the 20-year NPVRR, which comes from the stochastic mean (average) of 200 iterations of a portfolio as it is run in the dispatch model under varying market conditions. Each iteration provides the total annual cost of each component of total portfolio cost, including fuel costs, emissions costs, variable operations and maintenance costs, fixed operations and maintenance costs, energy export revenues (sales), energy import costs (purchases), capacity market sales revenue and capacity market purchases costs. Each annual cost category is then summed into a total portfolio cost and discounted by CEI South's weighted average cost of capital to arrive at the NPVRR. The lower the NPVRR is for a portfolio, the lower the rates can be to recuperate the cost to serve load over the next 20 years. The stochastic methodology allows for a rigorous analytical framework to determine the affordability of a portfolio.

The Reference case portfolio, which converts CEI South's two F-class combustion turbines into a large, combined cycle, was found to be the least cost portfolio by a wide margin across multiple potential future states; however, CEI South does not plan to convert either or both CTs to a combined cycle in the absence of a large load addition. The reference case, generated by computer modeling, is overbuilt for CEI South customer needs and relies on vastly more market energy sales to lower the NPVRR well below all other portfolios. The Indiana Commission instructed that this is a risky proposition for a company of this size in Cause No. 45052. CEI South's preferred portfolio complies with this view.

The preferred portfolio was determined to be among the lowest cost portfolios across the 10 candidate portfolios, with a 20-year NPVRR of $4,502 million. This NPVRR is 6.7% higher than the Reference case portfolio but only 0.1% higher than the next lowest cost portfolio, a difference of less than $4 million over 20 years on a net present value basis. The preferred portfolio is nearly $80 million less expensive than the Business as Usual which continues F.B. Culley 3 on coal (the eighth most expensive portfolio in this objective category), which saves customers money in the long term.

9.1.3 Future Affordability (Cost Risk)

The Cost Risk minimization objective is measured in a similar way to the Affordability objective, using the 20-year NPVRR values from the stochastic analysis. However, this objective provides a measure of the 95th percentile of the NPVRR to determine an upper boundary (or worst-case perspective) of portfolio costs across the 200 stochastic iterations. The Cost Risk Minimization objective can be interpreted as follows: There is a 95% chance that total portfolio costs as measured by the 20-year NPVRR will be at or below this measure. In this way, the risk that total portfolio costs over 20 years can be measured, allowing for the selection of a portfolio that minimizes this risk. This in turn minimizes the risk that rates (prices) will be higher than the expected, where expected rates (costs) come from the Affordability objective.

The preferred portfolio performed well in the Cost Risk Minimization category. The 95th percentile of the 20-year NPVRR was determined to be $5,316 million, which is 7.4% higher than the Reference Portfolio 95th percentile of the 20-year NPVRR and within 0.1% ($3 million) of the next lowest cost portfolio. For this same objective, the preferred portfolio was found to be $170 million less than the Business as Usual portfolio, which is also the most expensive portfolio in this objective category. Accordingly, the preferred portfolio is shown to have a low level of cost risk relative to its own expected NPVRR as well as relative to the least cost portfolio, the most expensive portfolio and all other candidate portfolios.

In addition to the Revenue Requirement, the exposure to coal and gas markets must also be considered when evaluating cost risk. As commodity markets become more volatile the exposure to these market fluctuations may pose a risk to the overall portfolio. The portion of energy generation with exposure to these market risks was calculated using the total generation from coal and gas units divided by total fleet generation throughout the study period. The preferred portfolio performed well in this market risk category. The portfolio exposure to coal and gas markets was determined to be 27% of total generation. This shows a 29% decrease in exposure to coal and gas commodity price volatility from the Reference Case Portfolio (56%).

9.1.4 Environmental Sustainability

The Environmental Sustainability objective is determined from the stochastic analysis and is measured in two ways, CO_2 intensity (tons of CO_2/kWh) and by CO_2 equivalent emissions (stack emissions) in tons of CO_2e over the 20 year planning period. The latter was built with two suggestions from stakeholders. First CO_2e measures not only CO_2 but other emissions, such as methane and nitrous oxide. Conversion factors were applied to CO_2 from the Electronic Code of Federal Regulations (“eCFR”)[70,71] to convert to CO_2

[70] Methane (CH4) and nitrous oxide (N2O) emission factors for coal (bituminous) and natural gas taken from Table C-1 to Subpart C of 40 CFR Part 98. December 9, 2016.
[71] Chemical-specific Global Warming Potentials (GWPs) taken from Table A-1 to 40 CFR Part 98 Subpart A for a 100-year time horizon. December 11, 2014.

equivalence. Secondly, this metric measures total CO_2 tons that go into the atmosphere over the 20-year planning period verses picking a point in time. The development of these measures is described in detail in Section 2.3.2.3 and considers the total CO_2e emissions associated with the annual MWh of generation over 20 years from each technology type in the candidate portfolio.

The preferred portfolio performed very well in the Environmental Sustainability objective, reducing annual CO_2e emissions by more than 19 million tons over the 2023-2042 study period compared to the reference case and saves approximately 8.4 million tons of CO_2e compared to continuing the run F.B. Culley on coal. This portfolio has slightly less CO_2e emissions than the diversified renewables, which puts a similar level of CO_2e into the atmosphere as this portfolio on an annual basis. While the portfolio continues F.B. Culley 3 on natural gas, it is projected to run very little, serving as a low-cost peaking unit, preserving critical capacity needed for long duration weather events.

While not part of the balanced scorecard, by 2035 the preferred portfolio was found to reduce CO_2 emissions in the reference case by approximately 98% compared to the baseline year of 2005. This represents an annual reduction of nearly 9.4 million tons of CO_2 from the baseline of 9.6 million tons of CO_2, with the small remainder driven mostly by the new combustion turbines needed to support this renewable generation portfolio.

9.1.5 Future Affordability (Market Risk Minimization)

The Market Risk Minimization objective is applicable to both energy market risk and capacity market risk. The greater the energy market purchases that are required by a candidate portfolio, the greater the exposure to the risk that energy prices will be higher than the short-run marginal cost of energy production from the CEI South fleet. Similarly, the greater the capacity market purchases that are required by a candidate portfolio, the greater the exposure to the risk that capacity market purchase prices will be higher than the cost of adding capacity to the CEI South fleet. Conversely, the greater the energy market sales by a candidate portfolio, the greater the exposure to the risk that energy prices will be lower than the short-run marginal cost of energy production from the CEI South fleet. Similarly, the greater the capacity market sales by a candidate portfolio, the greater the exposure to the risk that capacity market purchase prices will be lower than the cost of capacity in the CEI South fleet, meaning the portfolio is overbuilt. In either case, heavy reliance on market sales could lead to inflated valuation of a portfolio.

The preferred portfolio performed relatively well in terms of energy market risk minimization, averaging 26% energy purchases as a percentage of generation. This figure is among the best of the 10 candidate portfolios. The best portfolio was the Reference Case (12%). The preferred portfolio near the middle in terms of energy sales with a figure of 19% as a percentage of generation much less than the reference case portfolio at 33%, which performed worse than all other portfolios in this category. While, the preferred portfolio has some energy market risk, both in terms of its own measure and relative to the measures of other candidate portfolios, it has the greatest level of dispatchable resources among portfolios considered at 941 MWs, which can be turned on at peak periods to protect from extremely high priced energy.

The preferred portfolio performed very well in terms of capacity market risk minimization, demonstrating a figure of only 0.6% capacity market purchases as a percentage of peak load. This figure is the lowest of the 10 candidate portfolios, slightly better than the Business as Usual portfolio with 0.9% capacity market purchases. The conversion of F.B. Culley 3 reduces the need for significant levels of capacity purchases throughout the planning horizon, which is important since MISO is still projecting capacity shortages in the future. In the 2022/2023 planning year, MISO capacity price cleared at the maximum level, CONE. MISO continues to update market rules and mechanisms to ensure reliability and resilience of the grid as renewables become a much larger share of the region's portfolio. Maintaining capacity of F.B. Culley 3 for our customers during this time is an insurance policy to help protect affordability for our customers. While the preferred portfolio's NPVRR does benefit from capacity market sales at 12% as a percentage of peak load, there is more cost risk to customers from being exposed to capacity purchases than the benefit it provides in the form of a lower NPVRR over the long term. Since portfolios were built to maintain relatively low capacity market exposure, all portfolios fall in a range from 8-13%.

9.1.6 Other Considerations

9.1.6.1 Future Flexibility

The preferred portfolio provides a low cost off ramp in the future, while eliminating customer exposure to coal fired generation. As MISO continues to update market rules and mechanisms, it is clear that some level of dispatchable resources will be necessary to maintain the reliability of the grid in the long-term. Today, there are no long duration (multiple day) battery storage options that are commercially viable. When such resources, or other new technologies, become cost competitive, CEI South can reevaluate this option in future IRPs. Until such time, CEI South customers will benefit from converting F.B. Culley 3 to natural gas.

9.1.6.2 Resiliency

The preferred portfolio offers CEI South customers with additional renewable energy but also provides dispatchable resources that will be able to back up these resources when needed to ensure reliability. The combustion turbines that will be installed at A.B. Brown will provide quick start/fast ramping capability when needed, and the natural gas fired Culley 3 will be available when needed for long duration peaking support, both with firm gas supply and access to multiple regions. These dispatchable resources are important to ensure reliability at all times, particularly when intermittent resources experience long duration droughts, periods of sustained high demand, or potential future winter weather events. CT's can also be black started, offering an additional degree of increased resiliency and operational flexibility.

9.1.6.3 Maintains Interconnection

The preferred portfolio maintains the existing 270 MW interconnection rights at F.B. Culley 3, protecting customers from untimely delays associated with a generation resource at another location, especially with the extensive MISO queue delays in recent years due to the record amount of interconnection requests submitted. In addition, it shields customers from potential transmission upgrade costs because the increase of interconnection requests is exhausting available transmission capacity. Lastly, maintaining the existing interconnection preserves the rights for replacement resources in future IRPs.

9.1.6.4 Reliability

The preferred portfolio was among the best portfolios in meeting MISO's Planning Reserve margin requirement in all seasons when tested in a full range of probabilistic load environments.

Reliability can be measured in different ways, but one common metric is whether the portfolio experiences unserved energy. The preferred portfolio was dispatched in the Encompass model using Reference Case inputs as well as the inputs from the four alternative scenarios, each of which had widely varying market assumptions for fuel prices, emissions prices, load and capital costs. In each of these deterministic dispatch runs, the preferred portfolio was not found to have a significant number of hours of unserved energy. Accordingly, the preferred portfolio was found to provide reliable service in meeting CEI South's expected load requirements over the 20-year study period. It contains two highly dispatchable combustion turbines (460 MW) to support a high penetration of renewables, ensuring reliability and provide a hedge against both the energy and capacity markets. These resources have quick start, fast ramping capability that can be turned on within 10 minutes. The portfolio also has 180 MWs of older CTs that can be turned on within 30 minutes, one of which provides blackstart capability. Maintaining F.B. Culley 3 as a converted gas peaking unit compliments CEI South's fleet of CTs as a further hedge against high energy prices. These thermal resources are still needed to maintain reliable service in multiday periods of cloud cover and no wind, allowing for a smooth transition into a renewables future locally and regionally as the

MISO system adapts to higher levels of renewables across the system. The portfolio maintains enough dispatchable generation to meet load demand when solar is not contributing to meet peak need and the wind may not be blowing. It was designed to meet the needs of CEI South customers in the worst weeks of each season, consistent with MISO's guidance.

As described in section 6.4.3 CEI south worked with 1898 to conduct analysis and review reliability for several alternative paths for F.B. Culley, including conversion to gas, retirement, and replacement with battery storage. This near-term assessment reviewed thermal loadings, voltage, VAR support, and transfer capability. No mitigations were identified in the F.B. Culley Conversion case, while upgrades were needed should F.B. Culley be retired or replaced with battery storage.

9.1.6.5 Operational Flexibility

The preferred portfolio includes a significant amount of Variable Energy Resources ("VER") (wind and solar) balanced by two 230 MW natural gas combustion turbines. The CT units can help to smooth out the intermittency of the VERs. The fast-ramping requirements of a system increase as the balance shifts toward increased VERs, particularly solar resources. The phenomenon known colloquially as the "duck curve" demonstrates the need for fast-ramping capability, a role that CTs perform well, to handle the onset of evening peak demand concurrent with rapidly declining solar output. Given the level of VER in the preferred portfolio (approximately 800 MW of wind and 1,000 MW of solar) together with the fast-ramping capabilities of the CT's, this portfolio is expected to meet all operational flexibility requirements.

Natural gas peaking CTs respond quickly to changing operational requirements, since there is no water to heat on a percentage of capacity per minute basis (as compared to a combined cycle unit). CTs are simple to operate, requiring few staff and resources to run properly and to maintain (typically under a long-term service agreement or LTSA) and often they can be started remotely. Note that CEI South maintains two 80 gas CTs, which can also be called upon when needed. One of which, includes black start capability, providing operational flexibility.

Given the high volume of intermittent renewable generation in the preferred portfolio CEI South feels it's critical to have an adequate amount of dispatchable generation to meet its obligation to ensure reliable service is provided to CEI South customers throughout the different seasons of the year as well as all 24 hours of the day. CEI South's experience shows that renewable generation can be unpredictable, therefore, a portion of generation should (a) provide a dispatchable (controllable) output (b) be able to start and stop more than once daily and be placed in service quickly and (c) respond to rapid changes in renewable output.

9.1.6.6 Resource Diversity

Resource Diversity is not an explicit objective in the balanced scorecard but is nevertheless an important criterion for a well-balanced portfolio. Resource Diversity allows a portfolio to avoid being dependent on one type of fuel or technology, which can expose the fleet to risks such as an extended cloudy period (reducing solar generation) or a fuel disruption that can come from a force majeure event on a gas pipeline. Resource Diversity also contributes indirectly to the other objectives discussed here, including operational flexibility, future flexibility and reliability. From this point of view, the preferred portfolio is reasonably diverse and well-balanced in terms of resources, with a mix of natural gas CTs, solar and wind resources, energy efficiency, demand response resources and a converted coal unit to natural gas, fed from a different gas pipeline than CTs.

CEI South is exploring the potential to add commercial and industrial demand response resources. 25 MW was included in the preferred portfolio, and CEI South is currently in discussions with a DR aggregator to explore the market potential in the Evansville area. Additionally, CEI South's AMI system now allows for a time based rate. CEI South is working with Cadmus to help develop a pilot program for a voluntary critical peak pricing rate. CPP better aligns the price customers pay for electricity with the cost of producing it by varying the price of electricity based on the time it's consumed. Customers are charged more for electricity during certain periods of peak demand, encouraging customers to use less energy during critical times. Customers that participate have the opportunity to lower their overall electricity spending by shifting load to lower cost hours. As generation becomes more intermittent and less controllable, it will be more important to shape load in the future. These demand based options will help to further diversify CEI South's resource mix.

9.1.6.7 Local Resources

CEI South prefers local resources for both capacity and energy needs. Local resources benefit CEI South customers by reducing cost risk and providing tax base, jobs and grid support for reliability.

Local generation also helps to minimize the risks of differences in cost between where power is produced and where it is consumed. When power is produced on system, customers minimize the likelihood of congestion charges, which can occur when delivering power via the transmission system. The chances of incurring these charges increases the further away energy must be delivered. Local generation also reduces the need to construct new high voltage power lines to bring clean renewable power to our area. These transmission projects take years to complete, often require eminent domain and ultimately cost customers money.

Investing in local projects help produce tax base and jobs, which directly benefit the communities CEI South serves. Currently, CEI South generates tax revenues for primarily two counties, Posey and Warrick. The preferred portfolio continues to provide opportunities for continued investment in these counties with the potential to also provide tax base from generating resources in Vanderburgh, Gibson and Spencer counties. Communities where CEI South customers live can utilize this money to support school systems, police, parks and recreation and other critical support services. Additionally, these projects will continue to be operated by local employees that contribute to the local economy.

Local projects also help keep the system reliable. CEI South's preferred portfolio maintains a good balance between intermittent renewable generation and local, dispatchable generation that provides the system with voltage support and a physical hedge against instances of high market prices. This is particularly important for large, industrial customers that make up nearly half of CEI South load.

9.1.6.8 Stability (Transmission/Distribution)

The Culley Unit 3 conversion to natural gas was used as a base case for various study cases as the conversion to gas was treated as a MW for MW conversion. No issues were identified for this case. The retirement of Culley Unit 3 required the lowest number of transmission system network upgrades for alternate cases. Although the number of network upgrades was lower than other study cases, upgrades to the CEI South system were identified for voltage and reactive power support for this scenario. These upgrades included multiple capacitor banks at different system locations and the conversion of Culley Unit 2 to a 64MVAR synchronous condenser.

The reliance on imports from the MISO market into CEI South's area led to voltage concerns for post contingent conditions due to insufficient reactive reserves. CT's provide mitigation to these issues and can be used for reactive ("VAR") support in the MISO market. The all imports and all renewables cases studied presented voltage issues that could not be mitigated with existing facilities. These issues would require additional network upgrade projects to add reactive power support and could also potentially lead to the need for CEI South to make Reactive Power Payments to the MISO market to receive off-network support to maintain proper reactive power and voltage levels. These upgrades for reactive support would need to be studied in more depth to determine the placement of new facilities and to determine the type of devices needed. However, initial estimates for needed upgrades are estimated to be between $17.5 million (Culley Unit 3 retirement) and $25 million (BESS replacement of Culley 3) to maintain reliability and mitigate the voltage issues. This amount was not included in the NPVRR of this portfolio.[72]

Studies were performed using the latest MISO generation interconnection system models and all renewable resources studied were assumed to be the projects already in the MISO queue and existing in the model. Additional study will be required on the preferred portfolio once specific renewable projects are identified and sited to determine any further impacts on the CEI South transmission and distribution electric system.

9.1.6.9 Economic Development

The preferred portfolio allows CEI South to provide solutions to assist with manufacturers' renewable and sustainable energy goals. Companies are setting these goals leading to a reduction in fossil fuels consistent with their sustainability strategies. If these companies cannot find a solution with their local utility partners, they may procure energy from other sources or make strategic decisions to relocate manufacturing load.

Renewable energy investments are important steps in facilitating the ability to provide CEI South customers with a portion of their energy requirements via renewable energy. With proper oversight and investment strategy renewable energy can be more efficient and cost-effective for many customers as compared to securing their own sources of energy which requires land and/or capital investments.

The communities in CEI South's service territory will benefit to the extent the addition of renewable energy supports growth among CEI South South's large customers or attracts new customers. The creation of additional jobs in the communities CEI South serves has a ripple effect on the local economy. Moreover, renewable energy projects will create construction jobs in the community and provides additional income for landowners, which

[72] These amounts are a subset of total costs discussed in Section 6.4.3

also will benefit the local economy. Ultimately, renewable energy projects support the attraction and retention of large customers.

Although CEI South supports cost effective and reliable renewable energy projects, CEI South must maintain strategic planning in the event large industrial customers locate to SW Indiana and require baseload generation for production. Site selectors and large industrial power users are typically sophisticated and fully understand the requirements to apply, receive approval and execute generation buildout. Comprehensive generation planning inclusive of renewable energy and dispatchable resources must be properly balanced to continue economic growth for our region.

For industrial customers to maintain their required voltage level, the CEI South system must be able to supply an adequate amount of reactive power (VARs). Transmission planning studies have shown that this cannot be accomplished without on-network reactive power supplying facilities, such as local synchronous generation. The CTs in the preferred portfolio provide this needed reactive power support. Even when they are not dispatched normally, CTs are able to be started and brought online quickly if needed for CEI South system reliability. CTs also prevent CEI South from entering into Reactive Power Payments through the MISO market, which would impact CEI South customers' bills.

Importantly, the current plan offers flexibility and a hedge assurance, reducing market risk for customers. Specifically, CEI South must remain nimble and dynamic for prospective industrial customers and to be able to adapt to the potential need for CCGT build out. CEI South aggressively pursues manufacturing opportunities which has direct, indirect and induced economic benefits for the region and state of Indiana. CEI South's ability to attract and retain these types of customers is vital to the region's economic wellbeing. Job growth leads to increased earning opportunity for local residents at the same time raising state revenue and tax base. Additionally, large power users assist all CEI South customers with lower utility rates by spreading the fixed cost recovery requirements for the rate base.

In addition, large customers and site selectors understand the comprehensive risks of market rate pricing and the corresponding volatility. The current IRP plan and the opportunity for future baseload generation allows for customers to remain confident in CEI South's ability to provide safe, reliable and cost-effective service. CEI South's generation strategy is an essential service for customers and the region's economic growth capability.

9.1.7 Fuel Inventory and Procurement Planning

It is impossible to perfectly predict price fluctuations in commodity prices such as coal and natural gas. CEI South uses coal contract strategies intended to even out short-term price fluctuations, such as locking in prices for various overlapping time horizons. Normally these contract renewals are staggered in time to even out short-term price fluctuations. Coal suppliers and transportation providers generally require firm commitments on quantities; however, CEI South coal contracts include optionality to adjust tonnage up or down to help manage operational variability which impacts inventory levels. Currently CEI South utilizes non-firm pipeline delivery and gas storage for the existing peaking units. It is planned that the future flexible combustion turbines at A.B. Brown and F.B. Culley, when converted, will utilize firm pipeline supply contracts.

SECTION 10
SHORT TERM ACTION PLAN

10.1 DIFFERENCES BETWEEN THE LAST SHORT-TERM ACTION PLAN FROM WHAT TRANSPIRED

CEI South pursued all the items listed in the 2019/2020 IRP short-term action plan.

10.1.1 Generation Transition

Following the conclusion of the 2019/2020 IRP, CEI South began a generation transition plan to replace the majority of its coal fleet with 700-1,000 MW of solar, 300 MWs of wind, and two highly dispatchable natural gas combustion turbines. CEI South pursued this plan, which includes securitization of AB Brown units 1&2 to help customers with affordability, through multiple filings in Cause numbers 45501, 45600, 45754, 45786, 45836, 45839, 45847, 45564, and 45722.

Consistent with the short-term action plan in the 2019/2020 IRP, CEI South received approval in the 45501 Order for two renewable projects – the Posey County Solar Project and Warrick County Solar Project (collectively the “45501 Solar Projects”), which were selected from the 2019 All-Source RFP. Additionally, CEI South received approval in the Commission’s June 28, 2022 Order in Cause No. 45564 to construct two CTs.

CEI South has also obtained approval in the Commission’s May 4, 2022 Order in Cause No. 45600 to (1) enter into a PPA to purchase energy, capacity, and Renewable Energy Credits (“RECs”) from a 185 MWac solar project in Vermillion County, Indiana, over a 15-year term (the “Vermillion County Solar Project”); and (2) enter into a PPA, to purchase energy, capacity, and RECs from a 150 MWac solar project in Knox County, Indiana, over a 20-year term (the “Knox County Solar Project” and collectively the “45600 Solar Projects”).

CEI South received approval in the Commission’s January 11, 2023 Order in Cause No. 45754 to purchase and acquire, indirectly through a BTA, a solar facility in Pike County, Indiana, that will have an aggregate nameplate capacity of approximately 130 MWac (the

"Pike County Solar Project"). In addition, CEI South has requested a CPCN in Cause No. 45836 to purchase and acquire, indirectly through a BTA, a wind facility in MISO's Central Region, and CEI south has requested a CPCN in Cause No. 45847, to amend the Posey County Solar Project. Both proceeds are pending as of the date of submitting this IRP.

10.1.2 DSM

The 2019 IRP did support continued energy efficiency programs designed to save 1.25% of eligible retail sales. CEI South proposed the 2021-2023 Electric DSM Plan to obtain approval of programs to achieve this level of savings. The Commission approved this plan on February 3, 2021 in Cause No. 45387. Consistent with the 2019 IRP, the framework for the 2021-2023 filed plan was modeled at a savings level of 1.3% of retail sales adjusted for an opt-out rate of 77% eligible load.

10.1.3 Solar Projects

The 50 MW Troy Solar Project, approved in Cause No. 45086 was completed and began putting power onto the grid on January 22, 2022. This project, which is located in Troy, IN was the first large scale solar project for CEI South. Learnings from this project helped CEI South in selection of proceeding solar projects in the generation transition plan. Additionally, CEI South, in partnership with Scannell and DOE installed rooftop solar comprising about 120 kW that entered commercial operation in December 2022. As with pilots that proceeded this project (Oak Hill and Volkman) this project helped CEI South understand what is needed to design, construct, and operate a facility on a leased rooftop.

10.1.4 Wind Project

CEI South is currently negotiating with a developer to secure a 200 MW wind generation facility, located in MISO Zone 4, under a Build Transfer Agreement. As of the date of submission of this IRP, the CPCN is still pending before the Commission in 45836.

10.1.5 F.B. Culley 2

In the last 2019/2020 IRP, CEI South CEI planned to close its smallest, most inefficient coal unit, Culley 2 (90 MWs) by the end of 2023. The Coal Combustion Residuals Part A Rule has provided CenterPoint Indiana South with a path to continue operating F.B. Culley 2 through 2025 by constructing a CCR compliant pond to dispose of bottom ash. The class 5 cost estimate to construct the pond to handle bottom ash from F.B. Culley 2 and maintain the capacity accreditation from F.B. Culley 2 to meet the MISO PRMR was estimated at the time to be $6 million with a current construction cost estimate of $8.9 million. This was lower cost than bids the Company received to purchase market capacity to meet the projected shortfall. As such CEI South plans to continue to operate this unit into 2025 to help shield customers from high capacity cost, which cleared at MISO's maximum price, CONE, in the 2022/2023 planning period.

10.1.6 Environmental Permits for ELG/CCR

The bottom ash system at F.B. Culley Unit 3 was converted to a dry system in the Fall of 2020. Work has also been completed to convert the FGD system to zero liquid discharge technology. These two technologies make Culley Unit 3 fully compliant with the ELG rule and the NPDES permit requirements for Culley 3. This work was essential to remain in compliance with ELG/NPDES requirement to cease the discharge of Unit 3 bottom ash by December 31, 2020 and a requirement to meet effluent limitations for FGD wastewater by December 31, 2023. The ZLD technology, along with construction of a new lined pond, also facilitated the continued use of the East Ash Pond, which was necessary for continued operation of Culley 3 beyond April 11, 2021 under the CCR Part A rule. These investments were necessary in order for Culley 3 to continue operations.

The West Ash Pond at F.B. Culley completed closure in December 2020. The closure design includes the construction of a lined contact storm water pond, which receives contact storm water from various areas of the plant. The construction of this pond, along with the installation of the dry bottom ash and FGD ZLD technologies enable the upcoming required closure of the F.B. Culley East Ash Pond.

The A.B. Brown Ash Pond is also facing forced closure later this year. Plans are currently underway for the excavation of all material from the A.B. Brown ash pond, with a majority of the ash being sent for beneficial reuse.

10.2 DISCUSSION OF PLANS FOR NEXT 3 YEARS

The short-term action plan describes the early steps to pursue the preferred portfolio, consistent with the objectives and risk perspectives listed in Section 2.3. Progress on the items listed below will be tracked and reported on in the next IRP. IRP estimates of each piece of the plan listed below can be found in Confidential Attachment 8.2 EnCompass Input Model Files. Individual cost estimates can also be found in Section 6 Resource Options.

10.2.1 Procurement of Supply Side Resources

As described above, the preferred portfolio included conversion of F.B. Culley 3 to natural gas by 2027, adding an additional 200 MWs of solar by 2030, and an additional 200 MWs of wind by 2030. Additionally, it calls for the expansion of demand response programs where possible in the near and long term, with engagment from a DR aggregator to help understand and execute on potential commercial and industrial programs and a pilot to better understand potential of a time based rate. CEI South must continue to plan, as some portions are more certain than others.

CEI South plans to close its smallest, most inefficient coal unit, Culley 2 (90 MWs) by 2025, and CEI South's contract for joint operations of Warrick unit 4 (150 MWs) expires by the end of 2023. CEI South has acquired capacity in the 2023/2024 planning season and is working to secure needed capacity for the 2024/2025 planning year to help meet MISO's planning reserve margin requirement until the two combustion turbines come online, along with solar and wind resources identified in the 2019/2020 IRP. As CEI South plans to convert F.B. Culley 3 to natural gas by 2027, the company will also work to acquire renewable generation to be in place by 2030 to meet CEI South's customers energy and capacity needs. This equates to approximately 200 MWs of installed capacity from solar generation and 200 MWs of installed capacity from wind generation.

Given fundamental changes in the market, renewables projects now require much longer lead times than in previous IRP cycles. There will not be time to wait for the next IRP to begin pursuing suitable projects to meet the needs of CEI South customers by 2030. To fill this need, CEI South plans to pursue attractive projects from its 2022 All-Source RFP consistent with the findings in the 2022/2023 IRP, to the extent that they are still available. It is likely that CEI South will go out for another RFP over the next year to identify other projects. There is high demand for these projects in Indiana as other utilities are also working through their own generation transitions. Affordable pricing will be important.

10.2.2 DSM

CEI South has filed to extend it's 2021-2023 filed plan for 2024 electric DSM plan on May, 25, of 2023. The 2025-2027 DSM plan will be filed late 2023 or early 2024 with energy efficiency savings guided by the 2022/2023 IRP process. Once plans are approved by the Commission, the CEI South Oversight Board, including the OUCC, CAC and CEI South, will oversee the implementation of energy efficiency programs.

10.2.3 Solar Projects

CEI South plans to acquire a 191 MW solar project located in Posey County, Indiana ("Posey Solar"). The acquisition is contingent on IURC review and approval under Cause 45847. The Posey Solar project is expected to be placed in service in the first quarter of 2025.

Also, CEI South plans to acquire a 130 MW solar project located in Pike County, Indiana ("Crosstrack"). The Crosstrack solar project has received IURC approval and is expected to be placed in service in the first quarter of 2025.

In addition, CEI South has entered into three solar purchase power agreements ("PPA").

The first is a 100 MW 25-year PPA located in Warrick County, Indiana ("Rustic Hills II"). The PPA is contingent on IURC review and approval under Cause 45839. The Rustic Hills II solar project is expected to be placed in service in the second quarter of 2025.

The second is a 185 MW 15-year PPA located in Vermillion County, Indiana ("Vermillion Rise"). The PPA is contingent on IURC review and approval under Cause 45839. The Vermillion Rise solar project is expected to be placed in service in the second quarter of 2025.

And the third is a 150 MW 20-year PPA located in Knox County, Indiana ("Wheatland"). The Wheatland solar project has received IURC approval and is expected to be placed in service in the third quarter of 2024.

For the future 200 MW of solar generation in the preferred portfolio, CEI South will solicit proposals through a Request for Proposal ("RFP") process, evaluate proposals using quantitative and qualitative information, and select a solar project(s) to be to be brought forth to the IURC for approval in the CPCN process.

10.2.4 Wind Projects

CEI South plans to acquire a 200 MW wind project located in MISO Zone 4 ("Wind Project"). CEI South is currently in negotiation to finalize a Build Transfer Agreement "BTA") and is contingent on IURC review and approval under Cause 45836. The Wind Project is expected to be placed in service 2025 – contingent on MISO interconnection study results timing.

CEI South will also solicit proposals for wind projects through within the RFP process, evaluate proposals using quantitative and qualitative information, and select a 200 MW wind project to be brought forth to the IURC for approval in the CPCN process. The remaining 400 MW of wind generation will be reevaluated in the next IRP.

10.2.5 Conversion of FB Culley 3

CEI South will seek approval from the Commission to convert F.B. Culley 3 to natural gas by 2027, consistent with the preferred portfolio. CEI South worked with 1898 to study the design conversion of F.B. Culley 3 from coal to natural gas firing to provide cost estimates consistent with AACE Class IV estimates. These planning estimates need to be refined. CEI South plans to work with boiler equipment manufacturers, consulting engineers, and construction companies to provide construction level estimates and schedules. Refining the planning typically takes 36 months to complete preliminary engineering, material procurement, contract negotiations and execution, fabrication, installation and commissioning. CEI South will work with nearby pipelines for a firm service contract to supply the plant with natural gas. Converting FB Culley 3 to natural gas may trigger air permitting modifications. CEI South will work our consultants and IDEM to determine the appropriate permitting requirements.

10.2.6 Combustion Turbines

CEI South continues to work towards commercial operation of the combustion turbines approved in Cause No. 45564. The project kickoff commenced in December 2022, and CEI South provided the Commission with Notice-to-Proceed following FERC approval of the pipeline that will supply the plant. CEI South continues to work closely with the EPC to keep costs at budgeted levels. Planned Initial Operations remain as scheduled for April 2025, with Planned Substantial Completion for May 2025, ahead of the 2025/2026 MISO planning year. The project is expected to provide approximately 460 MWs of capacity and has quick start, fast ramping capability to support renewable generation.

10.2.7 Ability to Finance the Preferred Portfolio

The Company expects to have sufficient funds to finance the preferred portfolio through a combination of internally generated cash flow from operations, external capital markets activity, and capital contributions from its parent company. CEI South's secured debt ratings are currently A1/A with a stable outlook from Moody's Investors Services and S&P Global Ratings, respectively.

10.2.8 Continuous Improvement

CEI South takes continuous improvement seriously and works to ensure that improvement opportunities are evaluated and where appropriate implemented. This is done in several ways. First, CEI South participates in the Director's report process and listens to critiques of its IRPs from multiple stakeholders. Second, CEI South always conducts post IRP discussions with internal team members, as well as outside consultants to determine what can be done better in the next IRP. Third, CEI South participates in stakeholder meetings of other Indiana utilities and follows stakeholder feedback in those processes. Fourth, CEI South collects information on IRPs through news articles, conferences and Indiana's annual Contemporary Issues meeting. Finally, improvement opportunities come directly through the stakeholder process with formal and informal meetings, as they did throughout this IRP.

CEI South listened to concerns of stakeholders around the black box nature of Aurora modeling software and took action to evaluate alternatives. Encompass was recommended by Citizens Action Coalition as a tool that provides more transparency, allowing for better participation throughout the process. CEI South agreed with stakeholders that EnCompass could help improve the collaborative process. Additionally, CEI South also introduced tech-to-tech calls between formal public stakeholder meetings and shared draft modeling results throughout the process, seeking feedback along the way. This process, which was suggested by stakeholders, helped to provide a forum for more meaningful, consistent dialogue. CEI South benefited from these conversations, which helped to clarify differences of opinion and concerns in a timely manner. Ultimately, the process was strengthened. CEI South worked hard to be transparent throughout.

10.3 Implementation Schedule for the Preferred Resource Portfolio

Below is a general timeline for the Preferred Resource Portfolio, subject to change.

Figure 10-1 – Implementation Schedule

Year	Quarter	Activity
2023	Q2	File for 2021-2023 DSM Extention and submit the 2022/2023 IRP
	Q3	
	Q4	CEI South Rate Case to include request for TOU pilot and proposed updates to DR tariffs
2024	Q1	File for 2025-2027 DSM Plan
	Q2	Issue Renewable RFP for renewable project's indicative pricing
	Q3	File CPCN for Culley 3 NG Conversion
	Q4	Begin 2025 IRP
2025	Q1	
	Q2	File Renewable CPCN(s)[73]
	Q3	Culley 3 NG Conversion CPCN Order
	Q4	File the 2025 IRP

[73] Timing subject to change depending on availability of suitable resources

SECTION 11
TECHNICAL APPENDIX

11.1 CUSTOMER ENERGY NEEDS APPENDIX

11.1.1 Forecast Inputs

11.1.1.1 Energy Data

Historical CEI South sales and revenues data were obtained through the billing system. The billing system contains detailed customer information including rate, service, North American Industrial Classification System ("NAICS") codes (if applicable), usage and billing records for all customer classes (more than 15 different rate and customer classes). These consumption records were compiled in a spreadsheet on a monthly basis. The data was then organized by rate code and imported into the load forecasting software.

11.1.1.2 Economic and Demographic Data

Economic and demographic data was obtained from S&P Global (formerly IHS Markit) for the state of Indiana and the Evansville Metropolitan Statistical Area ("MSA"). S&P Global is a trusted source for economic data that is commonly utilized by utilities for forecasting electric sales. The monthly data provided to CEI South contains both historical results and projected data throughout the IRP forecast period. This information is input into the load forecasting software and used to project residential, commercial (GS) and industrial (large) sales.

11.1.1.3 Weather Data

Historical and normal HDD and CDD are derived from daily temperature data for the Evansville airport. HDDs are defined as the number of degrees below a base temperature for a given day. CDDs are defined as the number of degrees above s base temperature for a given day. Normal degree-days are calculated by averaging the historical daily HDD and CDD over the last twenty years. Historical weather data is imported into the load forecasting software and is used to normalize the past usage of residential and GS customers. Similarly, the projected normal weather data is used to help forecast the future weather normalized loads of these customers.

In reviewing historical weather data, Itron found a statistically significant positive, but slow, increase in average temperature. This translated into fewer HDD and more CDD over time. Itron's analysis showed HDD are decreasing 0.2% per year while CDD are increasing 0.5% per year. These trends were incorporated into the forecast. Starting normal HDD were allowed to decrease 0.2% over the forecast period while CDD increased 0.5% per year through 2039. Figure 11.1 and Figure 11.2 show historical and forecasted monthly HDD and CDD.

Figure 11.1 – Heating Degree Days

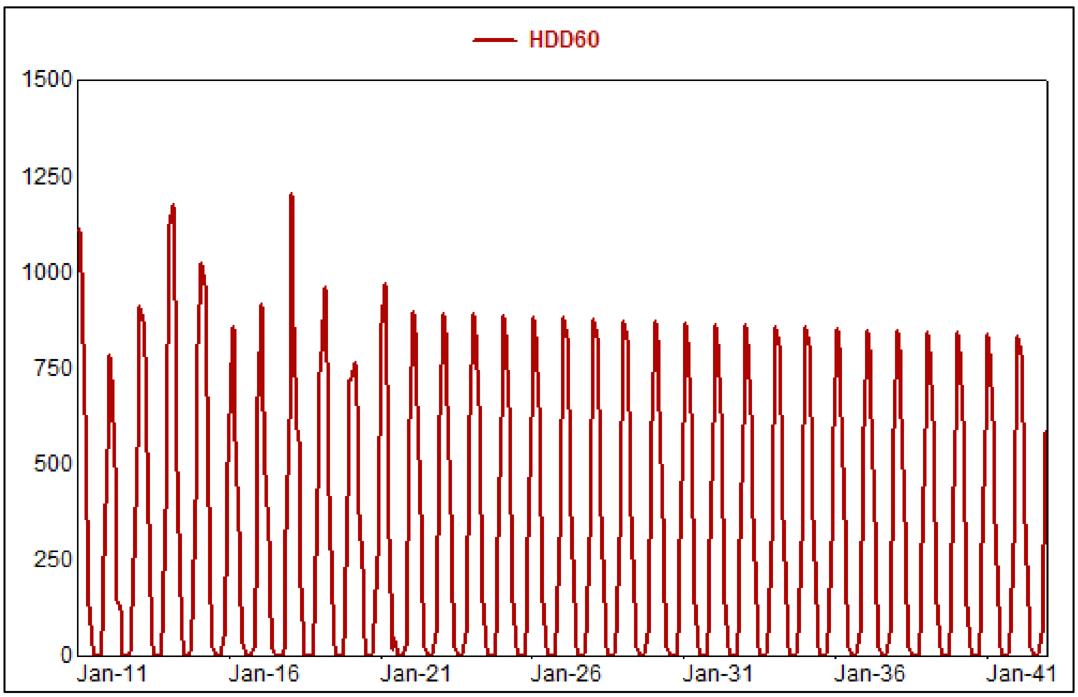
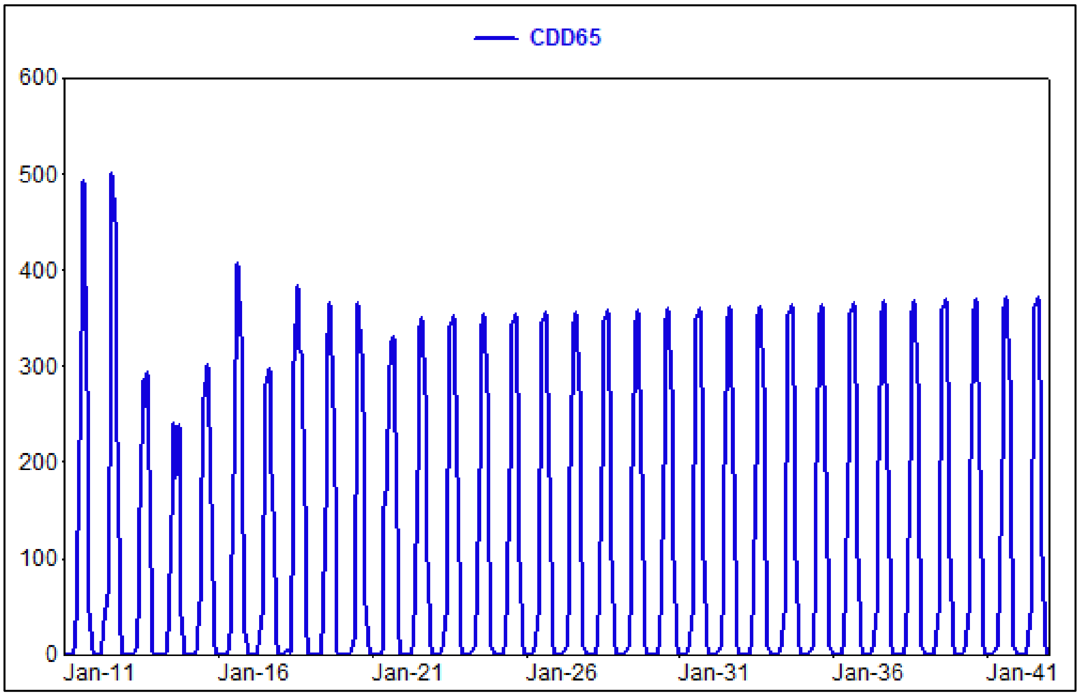


Figure 11.2 – Cooling Degree Days



11.1.1.4 Equipment Efficiencies and Market Shares Data

Itron Inc. provides regional EIA historic and projected data for equipment efficiencies and market shares. This information is used in the residential average use model and GS sales model. CEI South conducted an Electric Baseline survey in the third quarter of 2016 of CEI South's residential customers. This data was utilized to compare its territory market share data with the regional EIA data. To increase the accuracy of the residential average use model, regional equipment market shares were altered to reflect those of CEI South's actual territory.

11.1.2 Load Forecast Continuous Improvement

Itron continues to improve and evolve the SAE modeling framework. In addition to annually updating efficiency and saturations projections with the latest estimates from the EIA the framework has evolved to include utility specific DSM program activity data. The inclusion of a utility specific DSM variable in the modeling specification greatly improves model fit and enables the model to produce a baseline forecast excluding the impact of future DSM program activity. Additionally, Itron built a framework for the inclusion and use of trended normal weather where historical weather patterns show this to be appropriate.

The CEI South forecast now considers emerging technologies: customer distributed generation and electric vehicles. Customer owned PV adoption is modeled as a function of simple payback. The model explains historic adoption well and provides a framework that considers projected PV installation costs, electric prices and incentives. The adoption of electric vehicles is based on the consensus of EIA and Bloomberg's forecast of vehicle adoption. The result is a robust transportation model that includes a vehicle manufacturer component and a consumer choice component to estimate the mix of vehicles by powertrain type: gasoline, diesel, electric, plug-in hybrid electric, etc. The model accounts for projected fuel prices, electric prices, the decline in battery costs and federal incentives for electric vehicles.

Additionally, CEI South continually stays up to date with load forecasting topics in a variety of ways. First, CEI South is a member of Itron's Energy Forecasting Group. The Energy Forecasting Group contains a vast network of forecasters from around the country that share ideas and study results on various forecasting topics. CEI South forecasters attend an annual meeting that includes relevant topic discussions along with keynote speakers from the EIA and other energy forecasting professionals. The meeting is an excellent source for end-use forecasting directions and initiatives, as well as a networking opportunity. CEI South forecasters periodically attend continuing education workshops and webinars on various forecasting topics to help improve skills and learn new techniques. Additionally, CEI South discusses forecasts with the State Utility Forecasting Group and other Indiana utilities to better understand their forecasts. CEI South compares CEI South model assumptions and results to these groups to gain a better understanding of how they interpret and use model inputs.

11.1.3 Overview of Past Forecasts

The following tables outline the performance of CEI South's energy and demand forecasts over the last several IRPs by comparing Weather Normalized ("WN") sales and demand figurers to IRP forecasts from 2013-2022.

Weather-normalization is performed each month in order to analyze the variance from the forecast without the impact of weather. This is done by combining customer count, meter read schedule, billing month sales and daily temperature with estimates of the impact of changes in usage to variations of temperature. Underlying the estimates are average use models. Separate models have been estimated for residential and general service customer classes. These models have been estimated from historical billed sales and customer data. Actual weather data from NOAA is used to generate daily use per customer estimates for the revenue classes. The results are used to predict daily use estimates and are used to allocate billed monthly sales to the calendar-month period. The models are also executed using normal daily temperatures.

The following tables show the WN[74] and forecasted values for:

- Total Peak Demand
- Total Energy
- Residential Energy
- GS Energy
- Large Energy

[74] Note that large sales are not weather normalized.

Figure 11.3– Total Peak Demand Requirements (MW), Including Losses and Street Lighting

Year	2009 Total Demand Forecast (MW)	2011 Total Demand Forecast (MW)	2014 Total Demand Forecast (MW)	2016 Total Demand Forecast (MW)	2019 Total Demand Forecast (MW)	WN Total Demand (MW)	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.	2019 % Diff.
2013	1,115	1,156				1,144	2.6%	-1.0%			
2014	1,107	1,165				1,133	2.3%	-2.8%			
2015	1,100	1,164	1,155			1,113	1.1%	-4.6%	-3.8%		
2016	1,092	1,160	1,156			1,087	-0.5%	-6.7%	-6.3%		
2017	1,094	1,151	1,113	1,082		1,038	-5.4%	-11.0%	-7.2%	-4.3%	
2018	1,093	1,145	1,109	1,086		1,006	-8.6%	-13.8%	-10.2%	-7.9%	
2019	1,091	1,139	1,106	1,085	1,078	1,036	-5.3%	-9.9%	-6.7%	-4.7%	-4.0%
2020	1,084	1,144	1,106	1,088	1,106	984	-10.1%	-16.2%	-12.4%	-10.5%	-12.3%
2021	1,081	1,149	1,106	1,084	1,107	992	-9.0%	-15.8%	-11.5%	-9.2%	-11.5%
2022	1,076	1,155	1,107	1,083	1,129	988	-8.9%	-16.9%	-12.1%	-9.7%	-14.3%
Mean Absolute Error							5.4%	10.9%	9.5%	8.5%	12.9%

Figure 11.4 – Total Energy Requirements (GWh), Including Losses and Street Lighting

Year	2009 Total Energy IRP Forecast (GWh)	2011 Total Energy IRP Forecast (GWh)	2014 Total Energy IRP Forecast (GWh)	2016 Total Energy IRP Forecast (GWh)	2019 Total Energy IRP Forecast (GWh)	WN Total Energy Results (GWh)	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.	2019 % Diff.
2013	5,434	5,807				5,743	5.4%	-1.1%			
2014	5,403	5,803				5,797	6.8%	-0.1%			
2015	5,365	5,772	5,914			5,773	7.1%	0.0%	-2.4%		
2016	5,336	5,725	5,936			5,725	6.8%	0.0%	-3.7%		
2017	5,315	5,657	5,514	5,257		5,073	-4.8%	-11.5%	-8.7%	-3.6%	
2018	5,292	5,590	5,503	5,290		5,139	-3.0%	-8.8%	-7.1%	-2.9%	
2019	5,264	5,520	5,494	5,294	5,178	4,953	-6.3%	-11.5%	-10.9%	-6.9%	
2020	5,218	5,538	5,497	5,319	5,400	4,763	-9.6%	-16.3%	-15.4%	-11.7%	
2021	5,172	5,543	5,492	5,302	5,405	4,893	-5.7%	-13.3%	-12.2%	-8.3%	-10.5%
2022	5,134	5,554	5,494	5,303	5,527	4,716	-8.9%	-17.8%	-16.5%	-12.4%	-17.2%
Mean Absolute Error							6.4%	8.8%	10.6%	9.8%	13.8%

Figure 11.5 – Residential Energy (GWh)

Year	2009 Res. IRP Forecast (GWh)	2011 Res. IRP Forecast (GWh)	2014 Res. IRP Forecast (GWh)	2016 Res. IRP Forecast (GWh)	2019 Res. IRP Forecast (GWh)	WN Res. Results (GWh)	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.	2019 % Diff.
2013	1,391	1,419				1,421	2.1%	0.1%			
2014	1,365	1,399				1,412	3.3%	0.9%			
2015	1,332	1,371	1,404			1,444	7.8%	5.1%	2.8%		
2016	1,304	1,340	1,394			1,416	7.9%	5.4%	1.5%		
2017	1,282	1,305	1,383	1,407		1,398	8.3%	6.7%	1.1%	-0.6%	
2018	1,264	1,271	1,377	1,395		1,375	8.1%	7.6%	-0.2%	-1.5%	
2019	1,247	1,237	1,374	1,384	1,393	1,372	9.1%	9.8%	-0.1%	-0.9%	-1.6%
2020	1,218	1,240	1,373	1,375	1,386	1,408	13.4%	11.9%	2.5%	2.3%	1.5%
2021	1,216	1,239	1,370	1,366	1,376	1,414	14.0%	12.4%	3.1%	3.4%	2.7%
2022	1,222	1,244	1,373	1,362	1,378	1,378	11.3%	9.8%	0.4%	1.2%	0.0%
Mean Absolute Error							8.5%	7.7%	1.3%	1.9%	1.4%

Figure 11.6 – Commercial (GS) Energy (GWh)

Year	2009 Comm. (GS) IRP Forecast (GWh)	2011 Comm. (GS) IRP Forecast (GWh)	2014 Comm. (GS) IRP Forecast (GWh)	2016 Comm. IRP Forecast (GWh)	2019 Comm. IRP Forecast (GWh)	WN Comm. (GS) Results (GWh)	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.	2019 % Diff.
2013	1,304	1,383				1,294	-0.7%	-6.9%			
2014	1,307	1,399				1,312	0.4%	-6.6%			
2015	1,306	1,402	1,304			1,321	1.1%	-6.2%	1.3%		
2016	1,306	1,398	1,320			1,281	-1.9%	-9.1%	-3.0%		
2017	1,309	1,384	1,315	1,315		1,278	-2.4%	-8.3%	-2.9%	-2.9%	
2018	1,311	1,373	1,311	1,324		1,235	-6.1%	-11.1%	-6.1%	-7.2%	
2019	1,312	1,362	1,308	1,326	1,269	1,184	-10.8%	-15.1%	-10.5%	-12.0%	-7.2%
2020	1,308	1,374	1,311	1,325	1,280	1,117	-17.1%	-23.1%	-17.4%	-18.7%	-14.7%
2021	1,319	1,380	1,310	1,321	1,284	1,152	-14.5%	-19.8%	-13.8%	-14.7%	-11.5%
2022	1,332	1,389	1,313	1,322	1,290	1,156	-15.2%	-20.1%	-13.5%	-14.3%	-11.6%
Mean Absolute Error							7.0%	13.3%	9.6%	14.9%	11.5%

Figure 11.7 – Industrial (Large) Energy (GWh)

Year	2009 Ind. (Large) IRP Forecast (GWh)	2011 Ind. (Large) IRP Forecast (GWh)	2014 Ind. (Large) IRP Forecast (GWh)	2016 (Large) IRP Forecast (GWh)	2019 (Large) IRP Forecast (GWh)	WN Ind. (Large) Results (GWh)	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.	2019 % Diff.
2013	2,449	2,693				2,744	10.7%	1.9%			
2014	2,446	2,693				2,786	12.2%	3.3%			
2015	2,445	2,688	2,916			2,722	10.1%	1.2%	-7.1%		
2016	2,447	2,679	2,932			2,722	10.1%	1.6%	-7.7%		
2017	2,446	2,664	2,546	2,211		2,097	-16.7%	-27.1%	-21.4%	-5.5%	
2018	2,440	2,646	2,547	2,252		2,182	-11.9%	-21.3%	-16.7%	-3.2%	
2019	2,430	2,623	2,546	2,270	2,159	2,073	-17.2%	-26.5%	-22.8%	-9.5%	-4.1%
2020	2,419	2,625	2,549	2,312	2,348	1,971	-22.7%	-33.2%	-29.3%	-17.3%	-19.1%
2021	2,417	2,625	2,550	2,317	2,360	2,041	-18.4%	-28.6%	-25.0%	-13.5%	-15.6%
2022	2,410	2,622	2,550	2,322	2,464	1,942	-24.1%	-35.0%	-31.3%	-19.6%	-26.9%
Mean Absolute Error							15.4%	19.8%	22.0%	15.0%	21.3%

11.1.3.1 Actual and Weather Normalized Energy and Demand Levels

Figure 11.8 – Historic Peak Demand

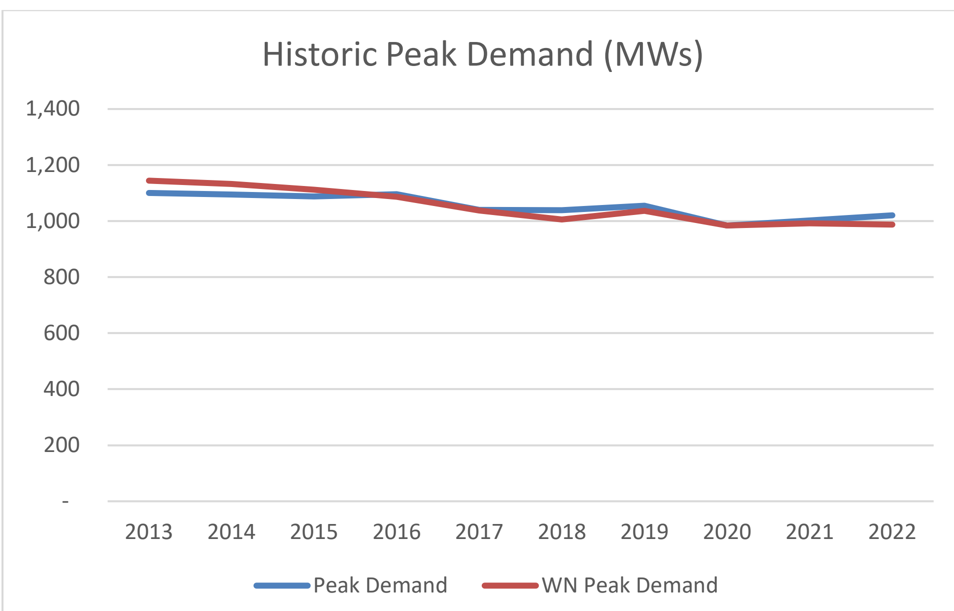
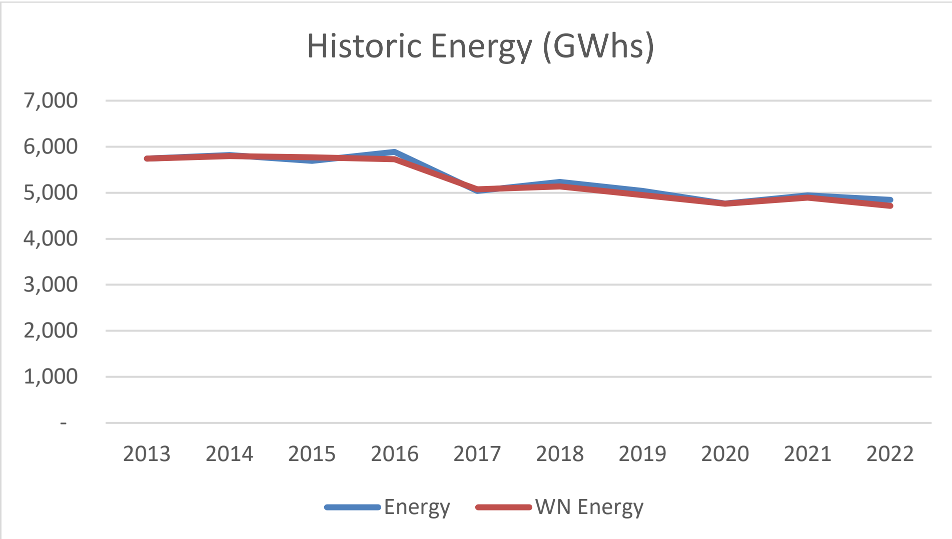


Figure 11.9 – Historic Energy



11.1.3.2 Load Shapes

Figure 11.10 – Historic Annual Load Shape

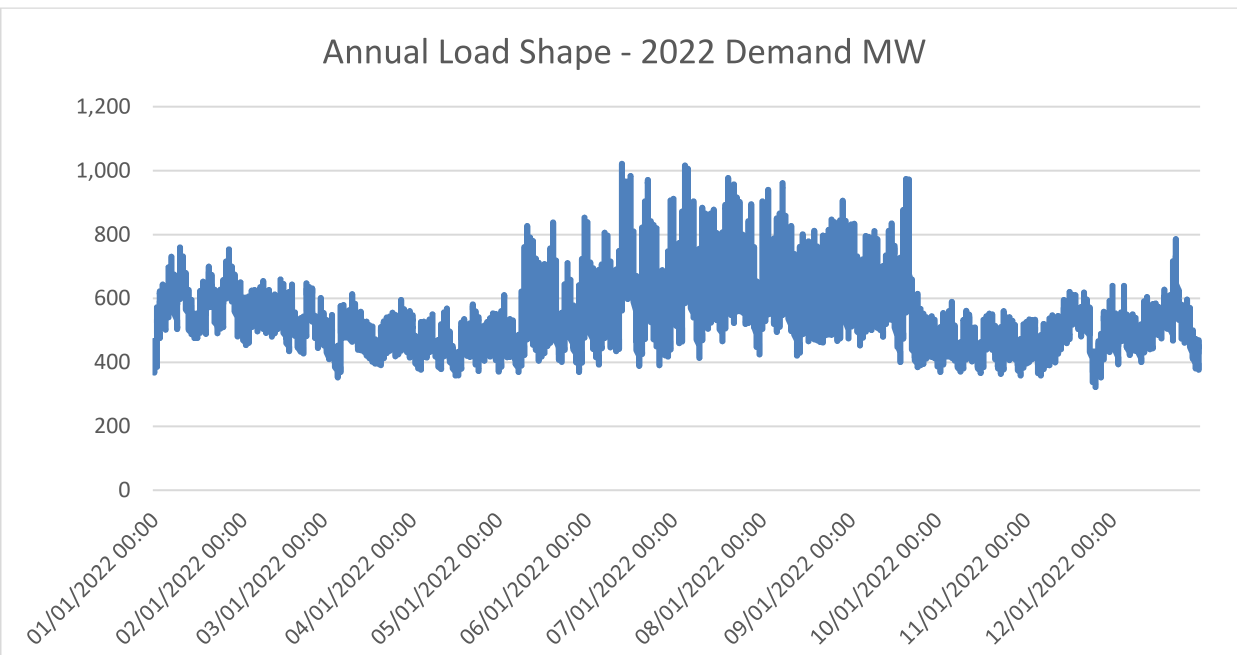


Figure 11.11 – Winter Peak Day

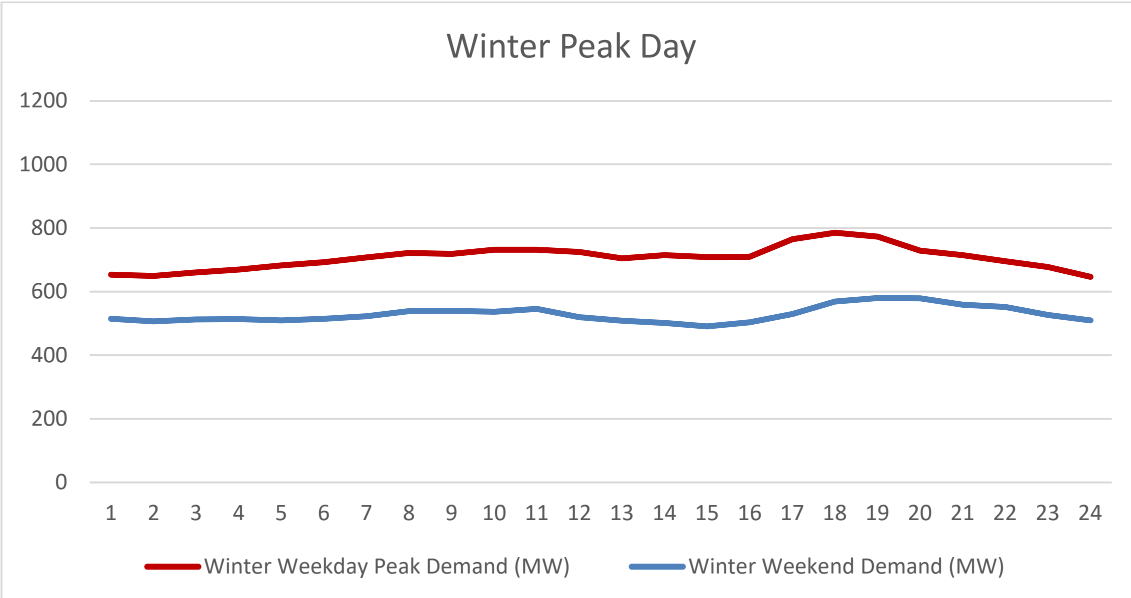


Figure 11.12 – Typical Spring Day

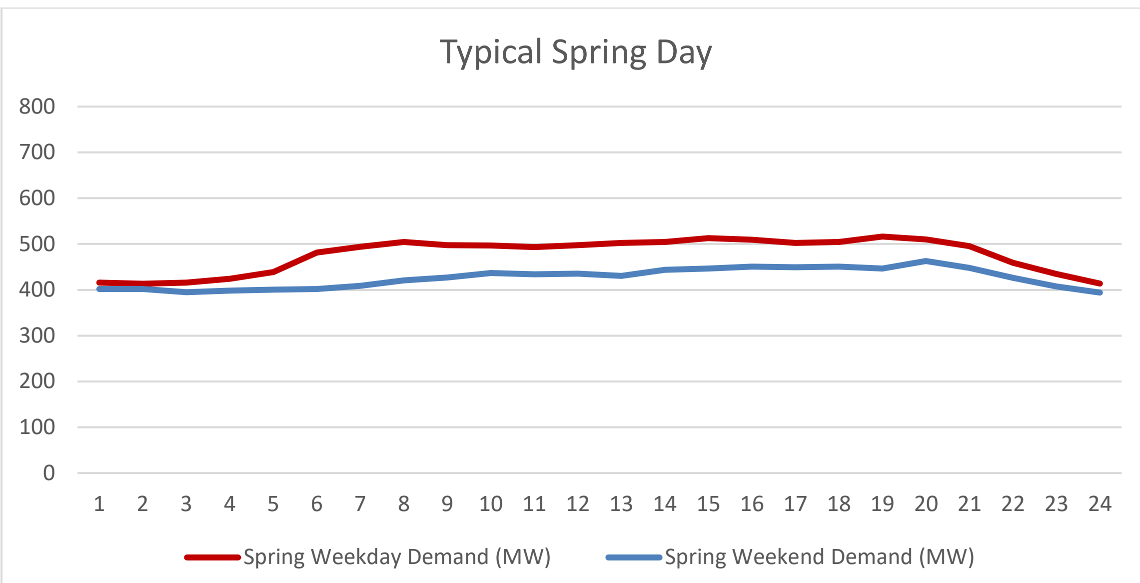


Figure 11.13 – Summer Peak Day

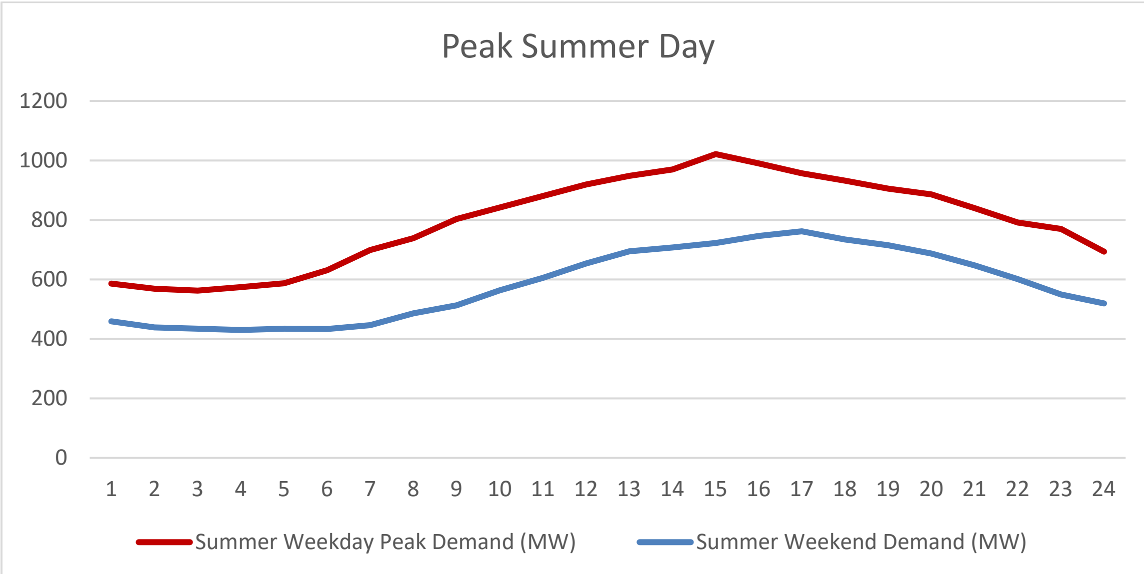


Figure 11.14 – Typical Fall Day

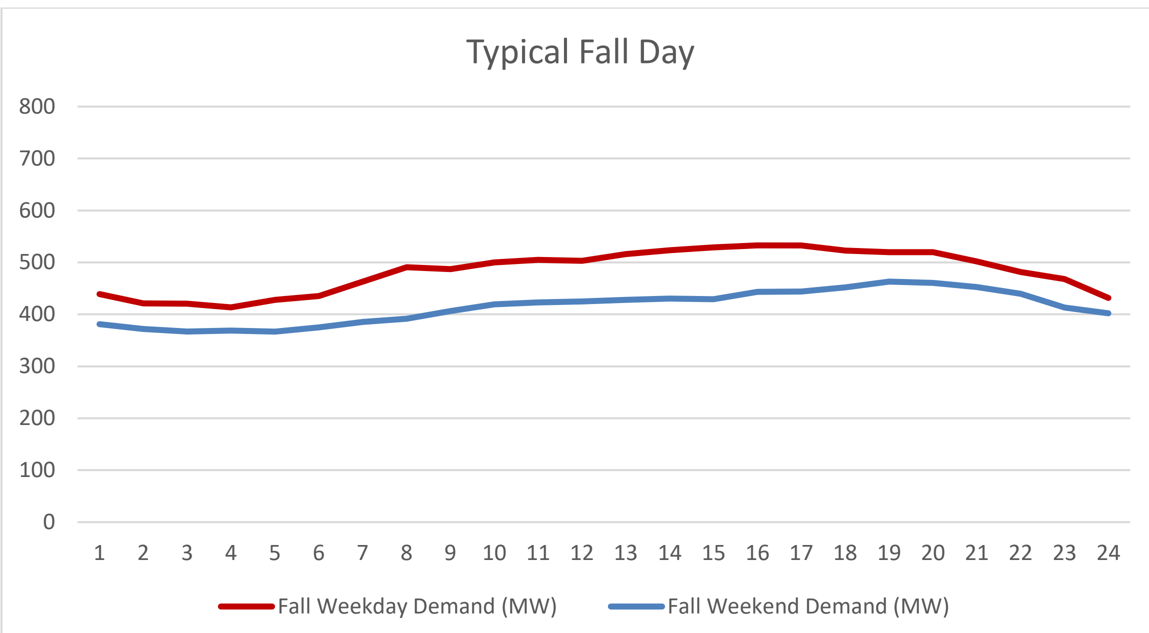


Figure 11.15 – January Load

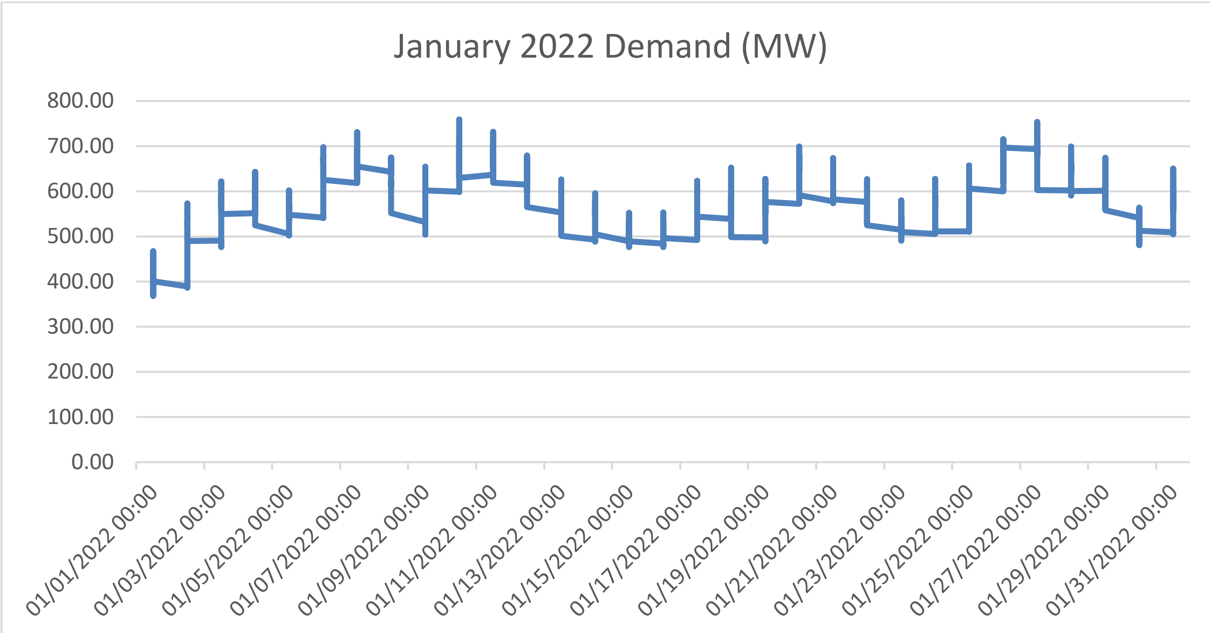


Figure 11.16 – February Load

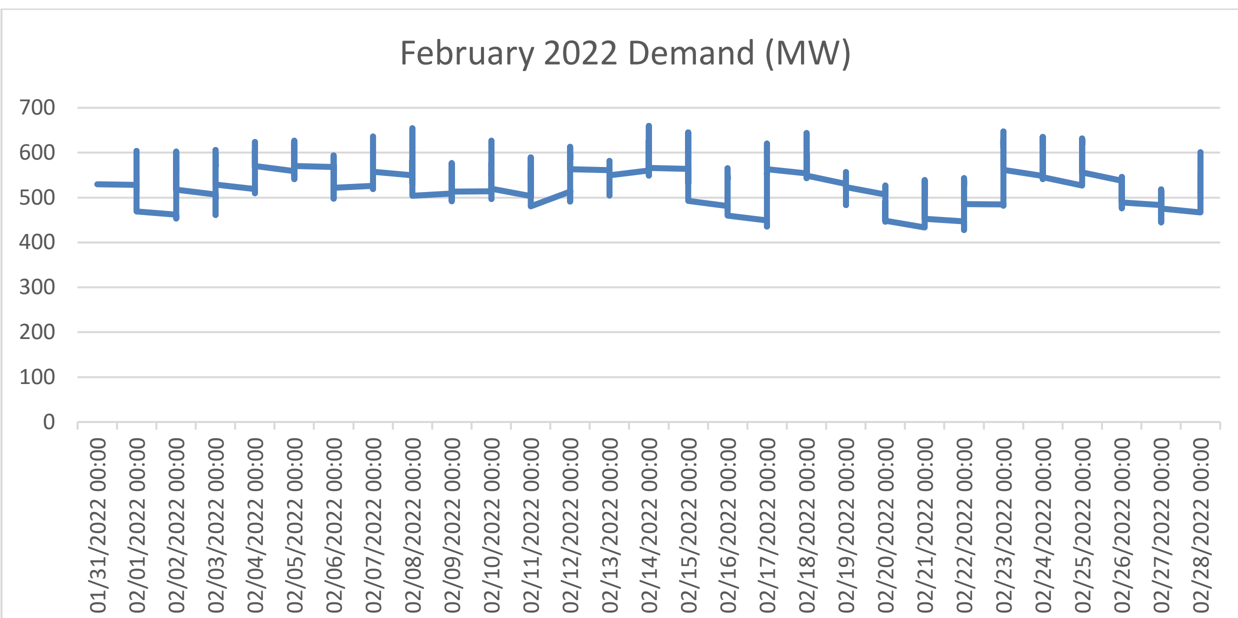


Figure 11.17 – March Load

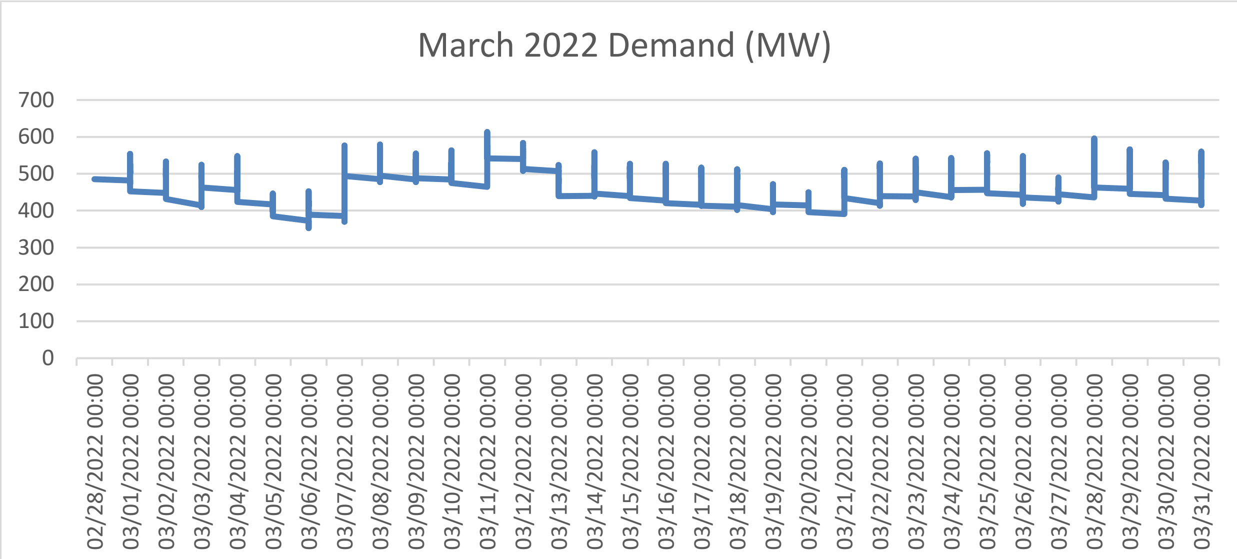


Figure 11.18 – April Load

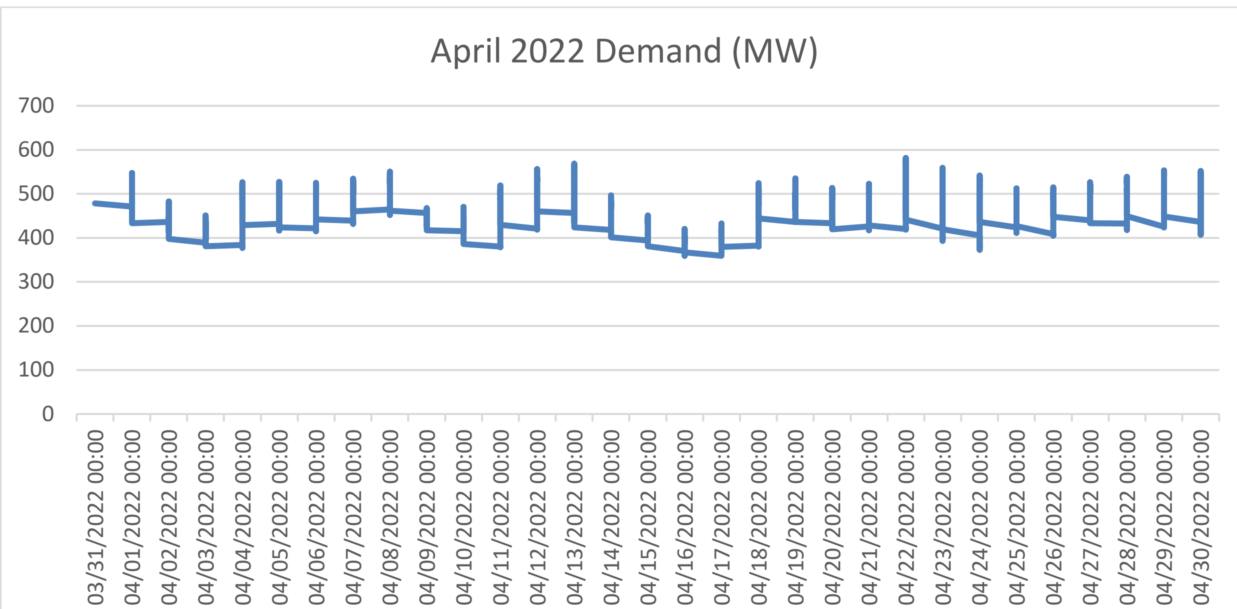


Figure 11.19 – May Load

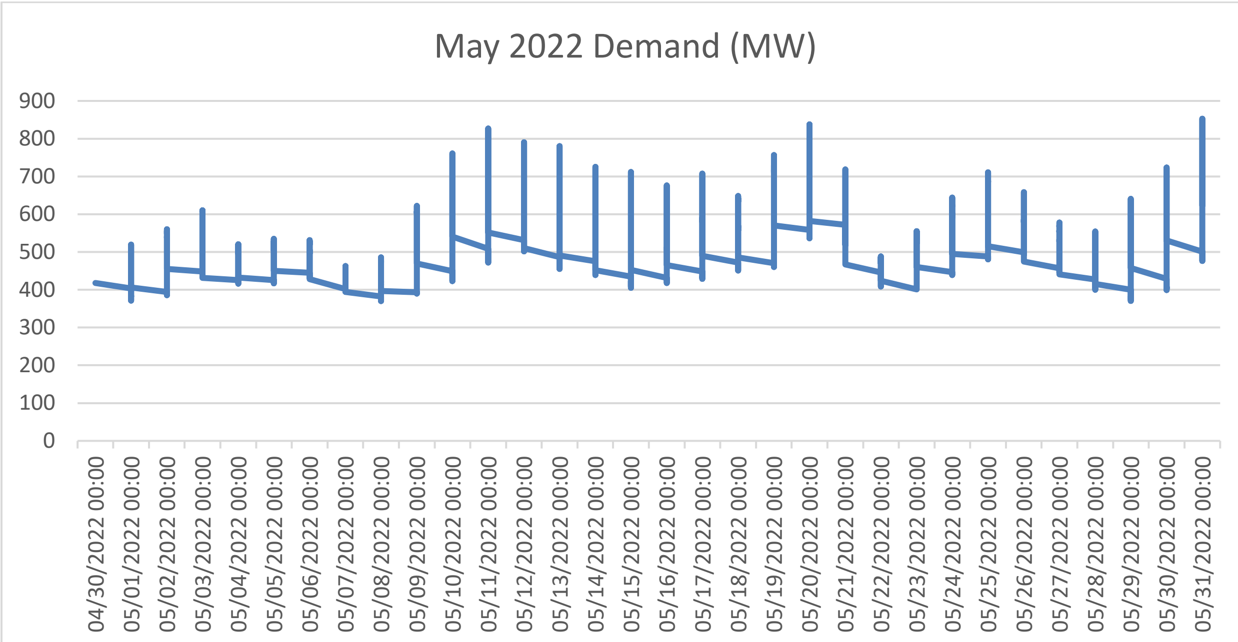


Figure 11.20 – June Load

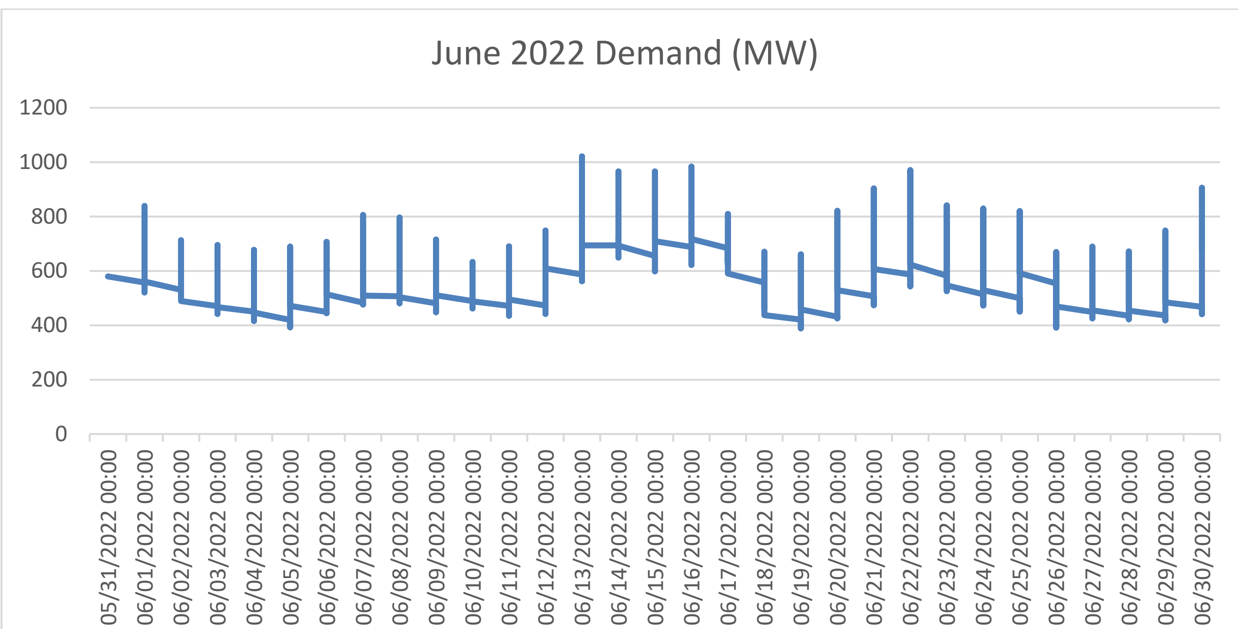


Figure 11.21 – July Load

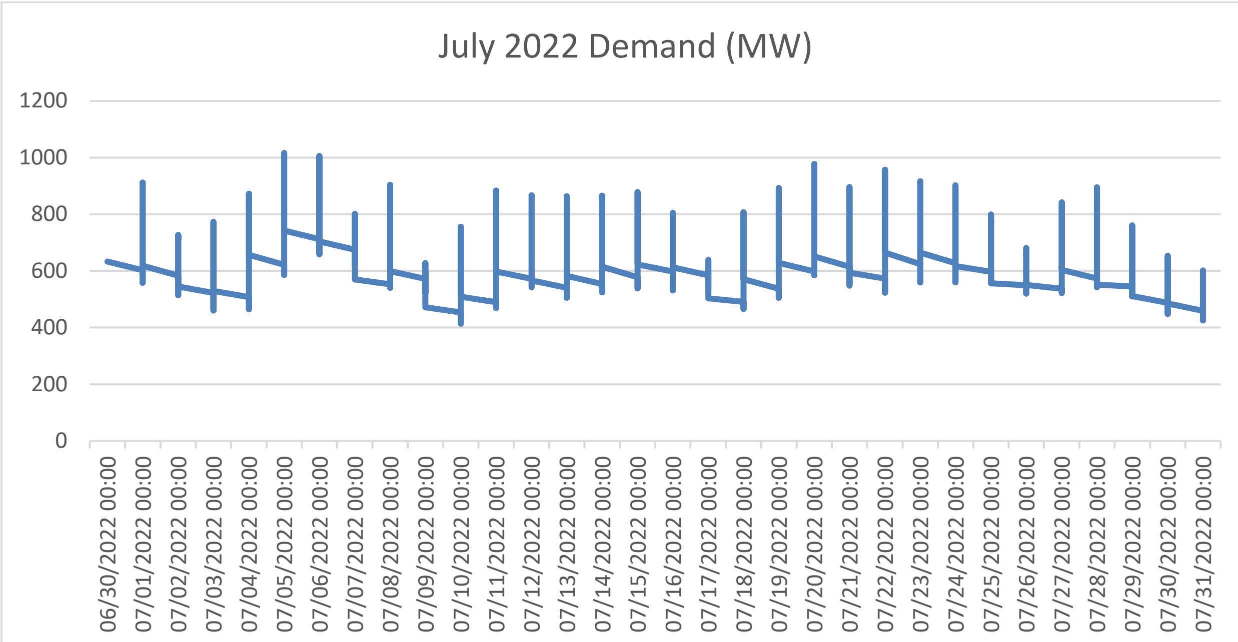


Figure 11.22 – August Load

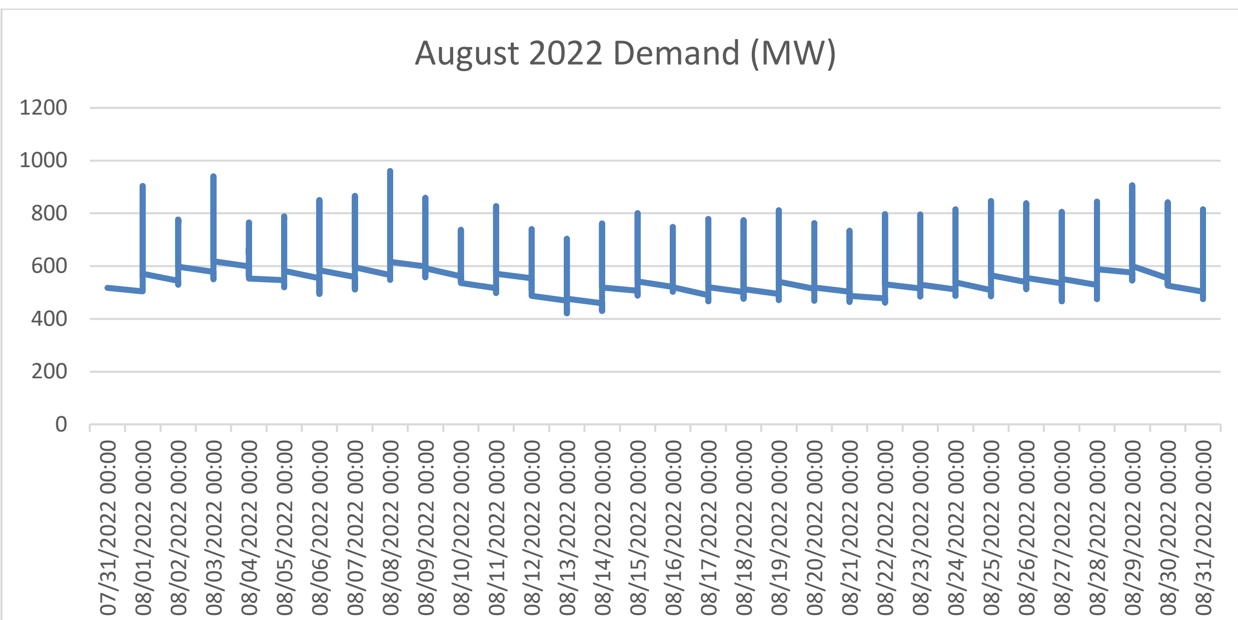


Figure 11.23 – September Load

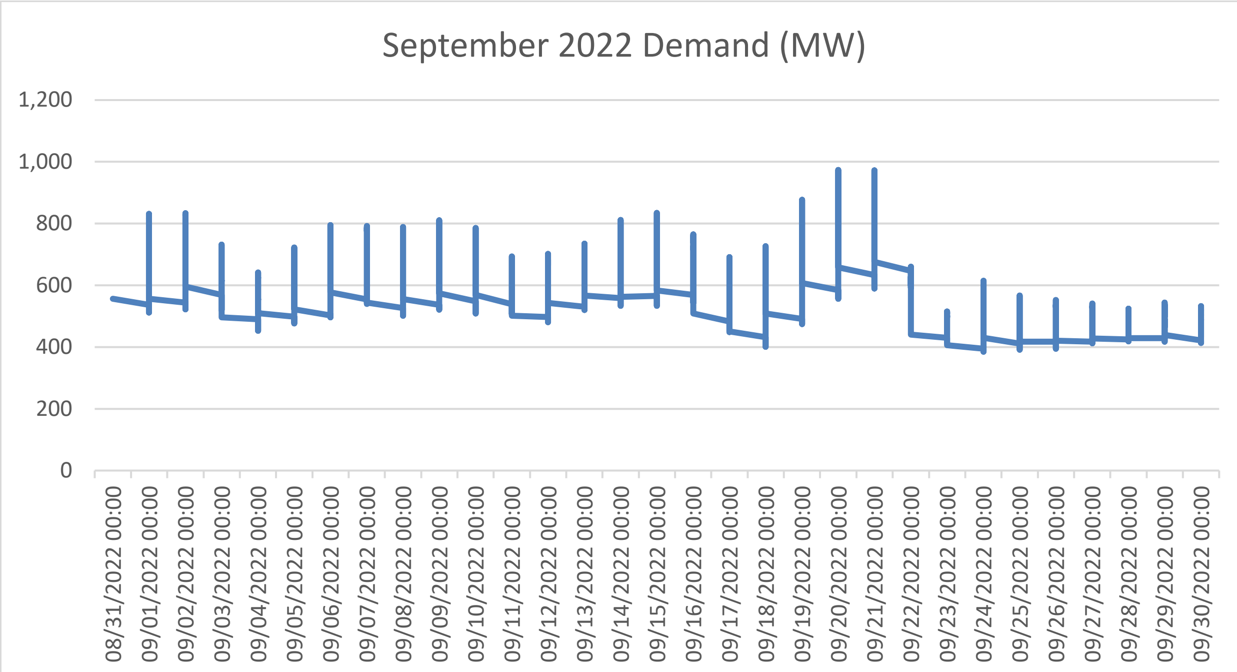


Figure 11.24 – October Load

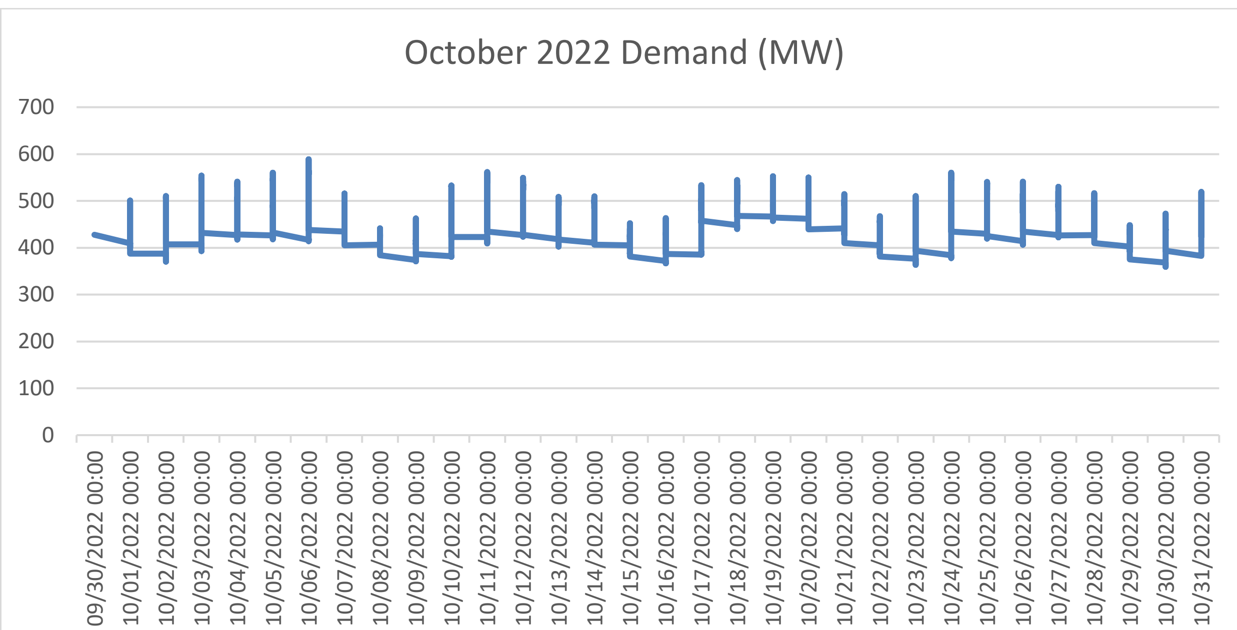


Figure 11.25 – November Load

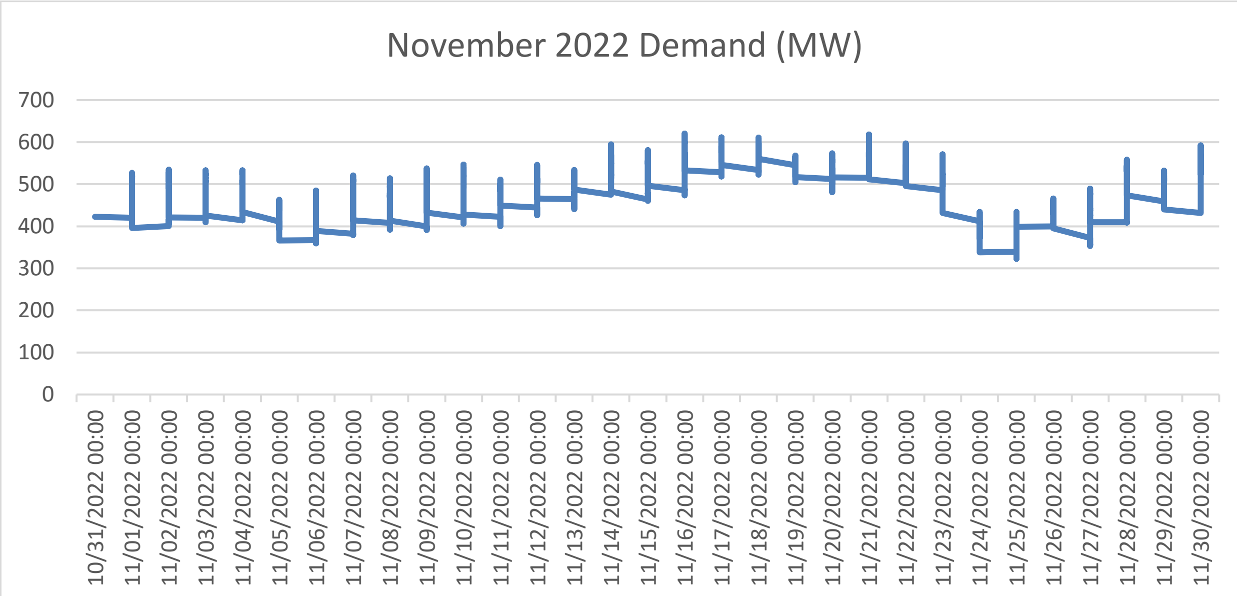
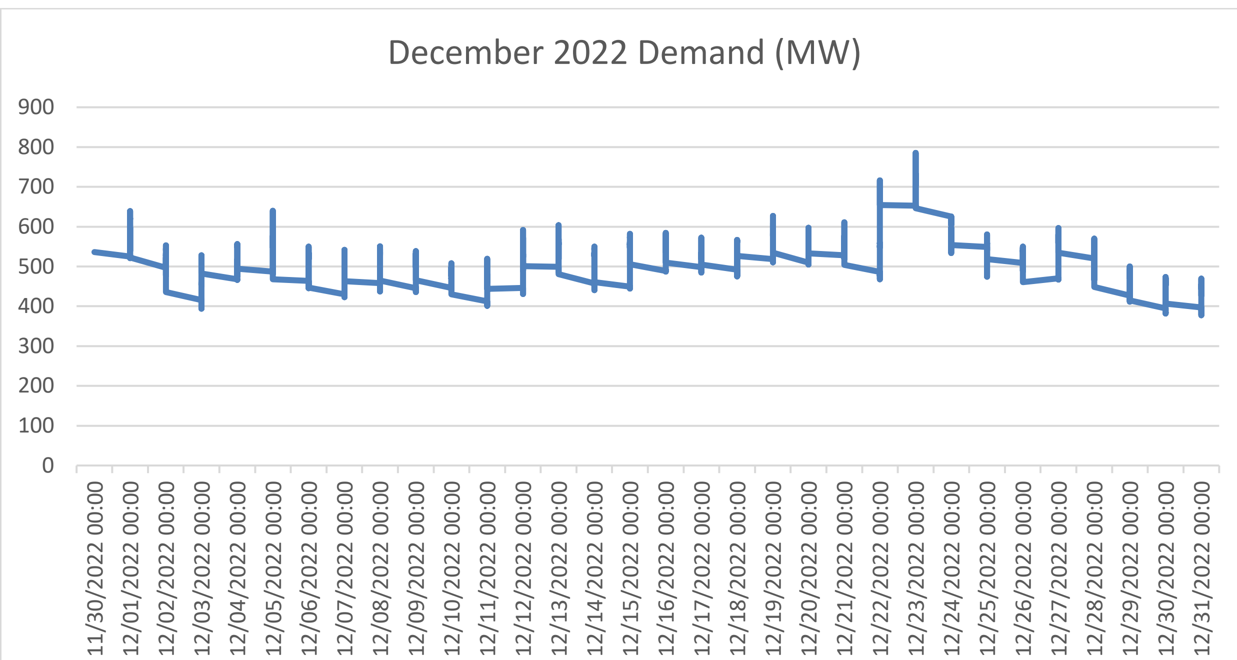


Figure 11.26 – December Load



11.2 ENVIRONMENTAL APPENDIX

11.2.1 Air Emissions

It was assumed that current or future generation resources would not exceed CEI South's allocated annual SO_2 and NOx emission allowances. CEI South's fleet of existing power generation facilities meet all rules and regulations related to SO_2 and NOx emissions while the cost of emission control equipment for SO_2 and NOx is factored into any new facilities that would be selected as part of a portfolio. However, the Revised CSAPR Update rule, finalized in March 2021 and effective beginning during the 2021 ozone season, reduced the number of seasonal NOx allowances that are allocated to electric generating units in 12 states. While CEI South has made operational and maintenance adjustments aimed at reducing NOx emissions during ozone season, the allocation reductions have resulted in CEI South having to purchase seasonal allowances from the market to cover the difference. On March 15, 2023, EPA released a pre-publication version of the Ozone Good Neighbor rule, which covers 23 states (an increase from the 12 covered by the Revised CSAPR Update rule) and will further revise the budget for the CSAPR NOx ozone season trading program. The rule also contains a "backstop" daily NOx emission rate that will apply beginning with the 2024 ozone season. Daily average emissions above the backstop rate will result in having to surrender extra allowances. This daily backstop emission rate, which is 0.14 lb/MMBtu, will apply to Unit 3 if finalized as proposed. Unit 3 currently has a 30-day rolling average NOx limit of 0.100 lb/MMBtu. The shorter averaging period will require CEI South to keep the daily average emission rate below the backstop rate in order to avoid having to surrender extra seasonal allowances. Air emissions allowance costs are accounted for within IRP modeling.

Figure 11.27 – Air Pollution Control Devices Installed

	F.B. Culley 2	F.B. Culley 3	Warrick 4	A.B. Brown 1	A.B. Brown 2
Vintage	1966	1973	1970	1979	1986
MW (net)	90	270	150	245	240
NO_X	Low NO_X Burner	SCR	SCR	SCR	SCR
SO_2	FGD	FGD	FGD	FGD	FGD

	F.B. Culley 2	F.B. Culley 3	Warrick 4	A.B. Brown 1	A.B. Brown 2
PM	ESP	FF	ESP	FF	ESP
MATs	Shared w/ U3	Injection	Injection	Injection	Injection
SO_3		Injection	Injection	Injection	injection

Figure 11.28 – CSAPR Seasonal NOx Allowances

	A.B. Brown	BAGS[75]	F.B. Culley	SIGECO W4	Total
2020	658	6	465	226	1355
2021	561	8	422	184	1167
2022	410	0	307	134	851
2023	TBD	0	TBD	TBD	TBD

11.2.2 Solid Waste Disposal

Scrubber by-products from A.B. Brown are sent to an on-site landfill permitted by Indiana Department of Environmental Management ("IDEM"). Since February 2010, the majority of A.B. Brown fly ash is diverted from the ash pond and sent for beneficial reuse to a cement processing plant in St. Genevieve, Missouri via a river barge loader and conveyor system. Recently, CEI South completed the infrastructure needed for the excavation and barge loading of ponded ash to also be sent for beneficial reuse in cement processing, to be sent for beneficial reuse by a cement processing plant in St. Genevieve, Missouri. This major sustainability project serves to mitigate negative impacts from the imposition of a more stringent regulatory scheme for ash disposal, as the majority of CEI South's coal combustion materials are now being diverted from the existing ash pond structures and surface coal mine backfill operations and instead transported offsite for recycling into a cement application. Additionally, these major sustainability projects serve to mitigate the negative impacts that are associated with closing the ash pond by leaving the CCR material in place.

Fly ash from the F.B. Culley facility is similarly transported off-site for beneficial reuse in cement. The F.B. Culley facility completed the conversion of the Unit 3 bottom ash system to a dry system in December 2020 and sends the bottom ash to beneficial reuse. The

[75] Retired

F.B. Culley facility recently completed construction of a GeoTube Containment Area that collects the bottom ash and drains the filtrate to a lined pond. The collected bottom ash will be sent to beneficial reuse. Additionally, the F.B. Culley facility recently completed the construction of a Spray Dryer Evaporator to handle the FGD Wastewater from the scrubber. The East Ash Pond (approximately 10 acres) is now no longer receiving any waste streams and will be closed. The West Pond (32 acres) completed closure in December 2020. The closure project included the construction of a new geosynthetic lined contact storm water pond that receives the coal pile run-off and other storm water that contacts industrial activity. Scrubber by-product generated by the F.B. Culley facility is also used for beneficial reuse and shipped by river barge from F.B. Culley to a wallboard manufacturer. In summary, the majority of CEI South's coal combustion material is no longer handled on site but is being recycled and shipped off-site for beneficial reuse.

11.2.3 Hazardous Waste Disposal

CEI South’s A.B. Brown and F.B. Culley plants are episodic producers of hazardous waste that may include paints, parts washer fluids, or other excess or outdated chemicals. Both facilities are typically classified as Small Quantity Generators. All hazardous waste is disposed of in accordance with Federal and state regulations.

11.2.4 Water Consumption and Discharge

A.B. Brown and F.B. Culley currently discharge process and cooling water to the Ohio River under NPDES water discharge permits issued by the IDEM. A.B. Brown utilizes cooling towers while F.B. Culley has a once through cooling water system. In fall 2014, both plants installed chemical precipitation water treatment systems to meet Ohio River Valley Sanitation Commission (“ORSANCO”) regional water quality standards mercury limit of 12 ppt monthly average.

11.3 DSM APPENDIX

11.3.1.1 DSM Planning Process

One of the key objectives of the IRP is to "provide all customers with a reliable supply of energy at the lowest reasonable cost." The level and costs of DSM to be offered in CEI South's service territory are important outcomes of the IRP process. The IRP will determine the appropriate level of DSM to include in the preferred resource plan. However, for CEI South, the IRP is not the appropriate tool to determine which specific programs to include in a DSM plan. Instead, every 2-3 years CEI South engages in a multi-step planning process designed to select programs that meet the level of savings established in the preferred resource portfolio. Once the level of DSM to be offered has been established by the IRP and a portfolio of programs to meet the savings levels has been designed, the last step in the planning process is to re-affirm the cost effectiveness of the proposed programs.

11.3.1.2 Cost Benefit Analysis

Utilizing the DSMore cost/benefit model, the measures and programs were analyzed for cost effectiveness. The model includes a full range of economic perspectives typically used in EE and DSM analytics. Inputs into the model include the following: participation rates, incentives paid, energy and demand savings of the measure, life of the measure, avoided costs, implementation costs, administrative costs, incremental costs to the participant of the high efficiency measure and escalation rates and discount rates. CEI South considers the results of each test and ensures that the portfolio passes the Total Resource Cost test as it includes the total costs and benefits to both the energy company (program administrator) and the consumer. The outputs include all the California Standard Practice Manual results:

- Participant Cost Test
- Ratepayer Impact Measure Test
- Utility Cost Test ("UCT")
- Total Resource Cost Test ("TRC")

The cost effectiveness analysis produces two types of resulting metrics:

- Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
- Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

The Participant Cost Test shows the value of the program from the perspective of the energy company's customer participating in the program. The test compares the participant's bill savings over the life of the DSM program to the participant's cost of participation.

The Utility Cost Test shows the value of the program to the utility considering only avoided utility supply costs (based on the next unit of generation) in comparison to the utility program costs.

The Ratepayer Impact Measure ("RIM") Test shows the impact of a program on all utility customers through impacts on average rates. This perspective also includes the estimates of revenue losses, which may be experienced by the utility as a result of the program.

The TRC Test shows the combined perspective of the energy company and the participating customers. This test compares (1) the level of benefits associated with the reduced energy supply costs to (2) the costs incurred by the energy company and by program participants. In completing the tests listed above, CEI South used 6.19% as the weighted average cost of capital, which is the weighted cost of capital that was approved by the IURC on May 29, 2019 in Cause No. 44910.

Figure 11.29 – CEI South Cost Effectiveness Tests Benefits & Costs Summary

Test	Benefits	Costs
Participant Cost Test	• Incentive payments • Annual bill savings • Applicable tax credits	• Incremental technology/equipment costs • Incremental installation costs
Rate Impact Measure Test	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs • Lost revenue due to reduced energy bills
6.19Utility Cost Test (Program Administrator Cost Test)	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs
Total Resource Cost Test	• Avoided energy costs • Avoided capacity costs • Applicable participant tax credits	• All program costs (not including incentive costs) • Incremental technology/equipment costs (whether paid by the participant or the utility)

11.3.2 Gross Savings 2021-2023

Figure 11.30 – 2021-2023 Plan Gross kWh Energy Savings

	2021[76]		2022[77]		2023[78]	
Sector	**Gross kWh Energy Savings**	**KW Demand Savings**	**Gross kWh Energy Savings**	**KW Demand Savings**	**Gross kWh Energy Savings**	**KW Demand Savings**
Residential	19,719,005	4,392	15,671,971	3,794	15,590,458	6,310
Commercial & Industrial	20,179,465	5,358	17,643,327	3,004	27,923,605	4,105
Total	39,898,470	9,750	33,315,297	6,799	43,514,063	10,415

[76] 2021 Evaluation Results used for 2021
[77] 2022 Evaluation Results used for 2022
[78] 2023 Operating Plan used for 2023 Savings

DSM Programs

CEI South has offered tariff-based DSM resource options to customers for many years. Consistent with a settlement approved in 2007 in Cause No. 43111, the Demand Side Management Adjustment ("DSMA") was created to specifically recover all CEI South's Commission approved DSM costs, including (at that time) a DLC Component. The Commission, in its order in Cause No. 43427, authorized CEI South to include both Core and Core-Plus DSM Program Costs and related incentives in an Energy Efficiency Funding Component ("EEFC") of the DSMA. The EEFC supports the Company's efforts to help customers reduce their consumption of electricity and related impacts on peak demand. It is designed to recover the costs of Commission-approved DSM programs from all customers receiving the benefit of these programs. In Cause Nos. 43427, 43938 and 44318, the Commission approved recovery of the cost of Conservation Programs via the EEFC. This rider is applicable to customers receiving service pursuant to Rate Schedules RS, B, SGS, DGS, MLA, OSS, LP and HLF.

11.3.3 Impacts

The table below demonstrates estimated energy (kWh) and demand (kW) savings per participant for each program.

Figure 11.31 – 2021 Evaluated Electric DSM Program Savings

Program	Residential/ Commercial	Participants *	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Specialty Lighting	Residential	153,173	35%	5,861,368	38	2,062,730	808	0.005	400.5
Residential Prescriptive	Residential	7,667	58%	3,371,863	440	1,955,763	1,658	0.216	1,495.5
Residential New Construction	Residential	256	57%	144,301	564	82,251	57	0.223	65.4
Income Qualified Weatherization	Residential	7,644	100%	374,823	49	374,823	56	0.007	112.0
Residential Behavioral Savings	Residential	49,228	100%	7,089,988	144	7,089,988	1,431	0.029	1,350.0
Appliance Recycling	Residential	1,497	52%	1,376,142	919	710,771	214	0.143	95.0
Smart Cycle (Smart Thermostats)	Residential	178	94%	90,238	507	85,073	-	-	550.0
Community-Based LED Distribution	Residential	53,672	91%	1,410,282	26	1,278,861	167	0.003	161.0
C&I Prescriptive	Commercial	31,062	76%	13,038,378	420	9,909,167	3,757	0.121	2,368.8
C&I Custom	Commercial	17	93%	1,714,556	100,856	1,594,537	376	22.098	578.3
Small Business Energy Solutions	Commercial	20,820	88%	5,426,531	261	4,775,347	1,225	0.059	449.7
Portfolio Total		325,215	75%	39,898,470	123	29,919,313	9,750	0.030	7,626.2

* Participants are the Verified installations

Figure 11.32 – 2022 Electric DSM Operating Plan Program Savings

Program	Residential/ Commercial	Participants	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Specialty Lighting	Residential	126,549	35%	5,209,860	41	1,838,599	718	0.006	253.5
Residential Prescriptive	Residential	6,772	60%	2,460,580	363	1,469,508	1,024	0.151	552.9
Residential New Construction	Residential	42	57%	20,933	498	11,932	8	0.200	4.8
Income Qualified Weatherization	Residential	3,217	100%	182,201	57	182,201	44	0.014	43.7
Residential Behavioral Savings	Residential	136,449	100%	5,396,100	40	5,396,100	1,684	0.012	1,684.5
Appliance Recycling	Residential	1,078	52%	1,009,663	937	521,359	155	0.144	83.3
Smart Cycle (Smart Thermostats)	Residential	82	94%	39,550	482	37,277	-	-	-
Community-Based LED Distribution	Residential	60,262	100%	1,353,085	22	1,353,085	160	0.003	160.2
C&I Prescriptive	Commercial	482	63%	10,641,878	22,079	6,704,383	1,532	3.178	964.9
C&I Custom	Commercial	47	58%	1,444,307	30,730	837,698	367	7.801	212.7
Small Business Energy Solutions	Commercial	14,686	88%	5,557,142	378	4,890,285	1,106	0.075	973.5
Portfolio Total		349,666	70%	33,315,297	95	23,242,425	6,799	0.019	4,933.9

* Participants are the Verified installations

Figure 11.33 – 2023 Electric DSM Operating Plan Program Savings

Program	Residential/ Commercial	Participants	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Prescriptive	Residential	22,079	56%	5,608,817	254	3,119,934	624	0.028	347.0
Residential New Construction	Residential	275	54%	42,857	156	23,143	29	0.105	15.7
Income Qualified Weatherization	Residential	760	100%	279,724	368	279,724	83	0.109	83.0
Community Connections	Residential	29,361	100%	591,172	20	591,172	18	0.001	17.9
Residential Behavioral Savings	Residential	44,661	100%	6,790,000	152	6,790,000	1,340	0.030	1,339.8
Appliance Recycling	Residential	1,370	67%	1,213,178	886	815,198	194	0.142	130.3
Conservation Voltage Reduction	Residential	4,491	100%	805,226	179	805,226	613	0.136	612.8
SmartDLC - Wifi DR/DLC Changeout	Residential	500	100%	259,484	519	259,484	550	1.100	550.0
BYOT (Bring Your Own Thermostat)	Residential	2,600	100%				2,860	1.100	2,860.0
Commercial & Industrial Prescriptive	Commercial	17,943	86%	15,000,000	836	12,900,000	2,567	0.143	2,207.8
Commercial & Industrial Custom	Commercial	59	96%	5,000,000	84,746	4,800,000	671	11.365	643.7
Small Business Direct Install	Commercial	181	93%	6,500,000	35,912	6,045,000	471	2.601	437.8
Conservation Voltage Reduction	Commercial	560	100%	1,423,604	2,542	1,423,604	396	0.708	396.3
Portfolio Total		124,840	87%	43,514,063	349	37,852,486	10,415	0.083	9,642.1

11.3.4 Avoided Costs

The avoided power capacity costs are reflective of the estimated replacement capital and fixed Operations and Maintenance ("O&M") cost. For this avoided cost analysis, a 236 MW 1x F-class simple cycle gas turbine was used as the comparison due to the low capital and fixed O&M costs. The operating and capital costs are assumed to escalate with inflation throughout the study period. Transmission and distribution capacity are accounted for within the transmission and distribution avoided cost.

The marginal operating energy costs were based off the modeled CEI South system marginal energy cost from the base optimized scenario under base assumptions. This included estimated capital, variable operation and maintenance and fuel costs. The marginal system cost reflects the modeled spinning reserve requirement and adjusted sales forecasts accounting for transmission and distribution losses.

The table below shows avoided costs when energy efficiency is selected through the IRP modeling process. As energy efficiency competes against other supply side resources and is selected, then the cost of a 236 MW 1x F-class simple cycle gas turbine is avoided.

Figure 11.34 – Avoided Costs

Year	Avoided Capital/O&M Cost $/kW	Transmission & Distribution Avoided Capital Cost $/kW	Total Capacity Avoided Cost $/kW	Natural Gas Forecast $/MMBtu	System Marginal Cost $/MWh
2023	$119.51	$9.31	$128.82	$5.68	$68.32
2024	$122.25	$8.94	$131.19	$4.65	$52.70
2025	$125.05	$8.82	$133.88	$4.43	$47.17
2026	$127.92	$8.94	$136.87	$4.50	$47.48
2027	$130.85	$9.15	$140.00	$4.57	$41.96
2028	$133.85	$9.42	$143.28	$4.70	$41.14
2029	$136.92	$9.63	$146.55	$4.87	$40.28
2030	$140.06	$9.91	$149.97	$5.05	$41.62
2031	$143.27	$10.19	$153.47	$5.23	$40.86
2032	$146.56	$10.36	$156.92	$5.39	$39.79
2033	$149.92	$10.60	$160.51	$5.55	$40.31
2034	$153.36	$10.85	$164.20	$5.72	$42.31
2035	$156.87	$11.11	$167.98	$5.83	$43.66
2036	$160.47	$11.36	$171.83	$6.03	$45.41
2037	$164.15	$11.61	$175.76	$6.26	$47.36
2038	$167.91	$11.88	$179.79	$6.48	$49.01
2039	$171.76	$12.15	$183.91	$6.71	$51.39
2040	$175.70	$12.43	$188.13	$7.00	$53.62
2041	$179.73	$12.72	$192.44	$7.22	$55.48
2042	$183.85	$13.01	$196.85	$7.59	$58.29

11.4 RESOURCE OPTIONS APPENDIX

11.4.1 Existing Resource Studies

11.4.1.1 Coal to Gas Conversion

The conversion of F.B. Culley Unit 2 and 3 existing coal fired boilers to burn natural gas instead of coal was studied. Conceptual design studies were developed by an engineering firm to determine natural gas conversion MW output, heat rate performance, emissions and balance of plant equipment. Engineering and construction estimates were developed to determine high level AACE Class IV installation costs. The converted unit 3 is expected to be operated as a peaking facility on 100% natural gas. Natural gas conversion of the units reduces boiler efficiency compared to the coal fired design and slightly increases net plant heat rate.

11.4.1.2 ACE Rule Compliance (CO_2 Proxy)

In the 2022-2023 IRP CEI South used the estimated costs for F.B. Culley 3 to comply with the ACE Rule as a proxy for future carbon legislation. These costs were originally developed for the 2019 IRP before retirement decisions were made for A.B. Brown 1 & 2 and FB. Culley 2. The sections below explain how these costs were originally developed for all coal units.

The Affordable Clean Energy ("ACE") rule, finalized by the United States EPA June 19, 2019 and ultimately vacated on January 19, 2021, established new standards for reducing greenhouse gas emissions for coal fired electric utility generating units. The rule was reinstated on October 27, 2022, thereby requiring states to submit their state plans required under the rule. On March 2, 2023, EPA extended the state submittal deadline to April 15, 2024. Most recently, on May 11, 2023, EPA announced a proposal to repeal the ACE rule. ACE details specific heat rate improvement techniques, called Best System of Emission Reduction ("BSER"), were meant to be the best technology options or other measures that have been known to reduce plant heat rate.

The specific candidate technology options are as follows:

- Steam turbine blade path upgrades.
- Redesign or replacement of the economizer.
- Air heater and duct leakage control.
- Variable frequency drive ("VFD") deployment.
- Neural networks.
- Intelligent sootblowing ("ISB").
- Boiler Feed Pump Upgrades.
- Equipment & facilities improvements to enhance O&M practices.

In the 2019/2020 IRP potential alternatives for improvements at the four coal fired units A.B. Brown Units 1 & 2 and F.B. Culley Units 2 & 3 were assessed to meet the goals of the ACE rule, on a 2019 Cost Basis. Applicability of candidate technologies for the four existing coal fired units is found in the "ACE Heat Rate Improvement Study" located in technical appendix 6.6. The characteristics of the four plants were reviewed and each plant was examined according to applicable BSER alternatives. Estimates of heat rate improvement, annual carbon dioxide reduction, O&M and a rough order of magnitude capital cost estimate were developed for each applicable alternative.

11.4.1.3 Cogeneration Study

A study was performed to evaluate the performance of a potential cogeneration partnership with a CEI South industrial customer. Conceptual design studies were developed by an engineering firm to determine the cogeneration MW output, capital cost, and O&M cost. Engineering and construction estimates were developed to determine high level AACE Class V estimates.

11.4.2 Approximate Net and Gross Dependable Generating Capacity

Figure 11.35 – Approximate Net and Gross Dependable Generating Capacity

	Gross Dependable Capacity (MW)	Net Dependable Capacity (MW)
A.B. Brown 1	265	245
A.B. Brown 2	260	240
A.B. Brown 3	74	74
A.B. Brown 4	74	74

	Gross Dependable Capacity (MW)	Net Dependable Capacity (MW)
F.B. Culley 2	100	90
F.B. Culley 3	287	270
Warrick 4	162	150
Troy Solar	50[79]	50

11.4.3 New Construction Alternatives

Figure 11.36 – New Construction Alternatives

Technology	Fuel	Screened	Capacity (kW)
Hydroelectric	Hydro	No	36,000/22,000
Generic Wind	Wind	No	200,000
Li-Ion Battery Storage (paired 50MW Generic Wind) (4 hour)	Storage	No	10,000
Generic Solar PV	Solar	No	10,000
Generic Solar PV	Solar	No	50,000
Generic Solar PV	Solar	No	100,000
Li-Ion Battery Storage (paired 50MW Generic Solar PV) (4 hour)	Storage	No	10,000
Li-Ion Battery Storage (4 hour)	Storage	No	10,000
Li-Ion Battery Storage (4 hour)	Storage	No	50,000
Li-Ion Battery Storage (4 hour)	Storage	No	100,000
Long Duration Storage	Storage	No	300,000
Demand Side Management Vintage 1 (2025-27)	Storage	No	Varies
Demand Side Management Vintage 2 (2028-30)	Storage	No	Varies
Demand Side Management Vintage 3 (2031-42)	Storage	No	Varies
Supercritical with Carbon Capture & Storage	Coal	No	500,000
Ultra-supercritical with Carbon Capture & Storage	Coal	No	750,000
F-Class CT	Natural Gas	No	229,000
J-Class CT	Natural Gas	No	372,000
GH-Class CT	Natural Gas	No	287,000
F-Class CCGT (Fired)	Natural Gas	No	363,000
F-Class CCGT (Unfired)	Natural Gas	No	365,000
GH-Class CCGT (Fired)	Natural Gas	No	428,000
GH-Class CCGT (Unfired)	Natural Gas	No	431,000
J-Class CCGT (Fired)	Natural Gas	No	1,101,000
J-Class CCGT (Unfired)	Natural Gas	No	551,000
Brown 5&6 Retrofit	Natural Gas	No	257,000

[79] Maximum output shown but output varies from season to season and day to day

Technology	Fuel	Screened	Capacity (kW)
Co-Gen	Natural Gas	Yes[80]	22,000
FB Culley Conversion	Natural Gas	No	Varies
Aeroderivative[81]	Natural Gas	No	255,000
Reciprocating Internal Combustion Engines (6x9)	Natural Gas	No	54,500
Reciprocating Internal Combustion Engines (618)	Natural Gas	No	110100
Small Modular Reactor	Nuclear	No	77,000
Annual MISO Capacity Market Purchase	Capacity	No	Varies

11.5 RISK APPENDIX

The probabilistic risk assessment allows for the development of portfolio results based on a range of possible input values developed from the same stochastic process. The probability risk assessment is based on defining uncertainty around monthly coal prices, natural gas prices, CO_2 prices, peak load and capital costs for solar, wind and storage. With the uncertainty around the variables defined by probability distributions, the variables were modeled stochastically using EnCompass' monte carlo sampling capability. 200 iterations were run to create 200 sets of stochastically developed inputs. These 200 sets of stochastic inputs were then run through the dispatch model one set at a time for the selected portfolios. 200 instances of key metrics from the dispatch modeling were used to form distributions around the key output metrics. Thus, stochastically developed inputs allow for the testing of each portfolio's performance across a wide range probable market conditions.

The development of probability distributions around uncertainty variables, combined with running these distributions through a stochastic process to develop 200 sets of inputs, is key to the probability risk assessment approach. The probability distributions used in the assessment are described in more detail below.

80 Co-generation facilities are dependent on being co-located with an industrial customer; this option was not considered in reference case optimization.
81 Aeroderivative units were not originally included as a new construction alternative and were later added and tested in specific runs based on RFP bid received.

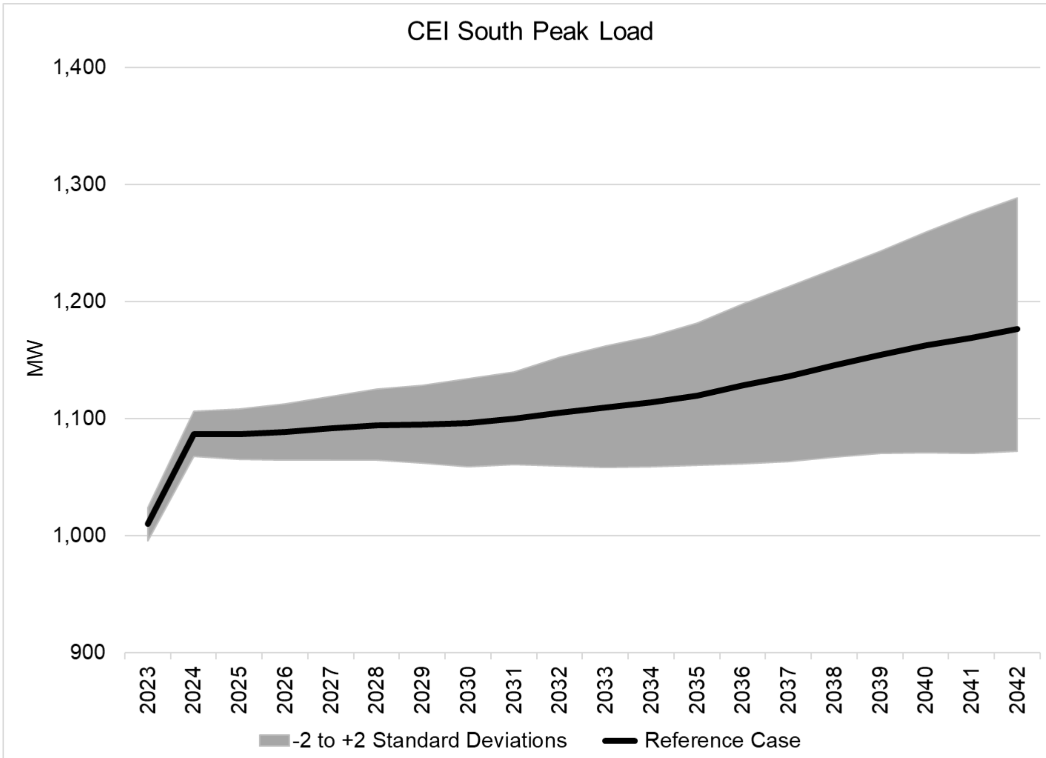
11.6 Probability Distributions

To perform the probabilistic modeling (stochastics), a set of monthly probability distributions that describe uncertainty was required for each of the key market driver variables described above (natural gas prices, coal prices, CO_2 prices, peak demand and capital costs for renewables). Monthly lognormal probability distributions were assumed for natural gas prices, coal prices and peak demand. Monthly discrete distributions were assumed for CO_2 prices and renewables capital costs. The lognormal probability distributions were stochastically simulated together in EnCompass with cross-variable correlation. 200 iterations were run stochastically, which produced 200 sets of correlated inputs for natural gas prices, coal prices and peak demand. This stochastics runs in EnCompass assumed 100 percent mean reversion. The discrete distributions for CO_2 prices and renewables capital costs were assigned to each of the 200 stochastic iterations based on assumed correlations. This resulted in 200 sets of probabilistic inputs that were then fed through the dispatch cost modeling. The following sections describe the methodologies for developing these stochastic variables.

11.6.1 Load Uncertainty

To account for electricity demand variability that derives from economic growth, weather, energy efficiency and demand side management measures, 1898 & Co. developed defined uncertainty around the monthly expected peak load for the CEI South control area. Varying the components that make up peak demand, 1898 & Co. developed a set of likely peak demand scenarios, ranging low end expectations to high end expectations. Monthly averages and standard deviations were developed from these demand scenarios and applied to a lognormal distribution to develop the monthly peak demand probability distribution used in the stochastic modeling.

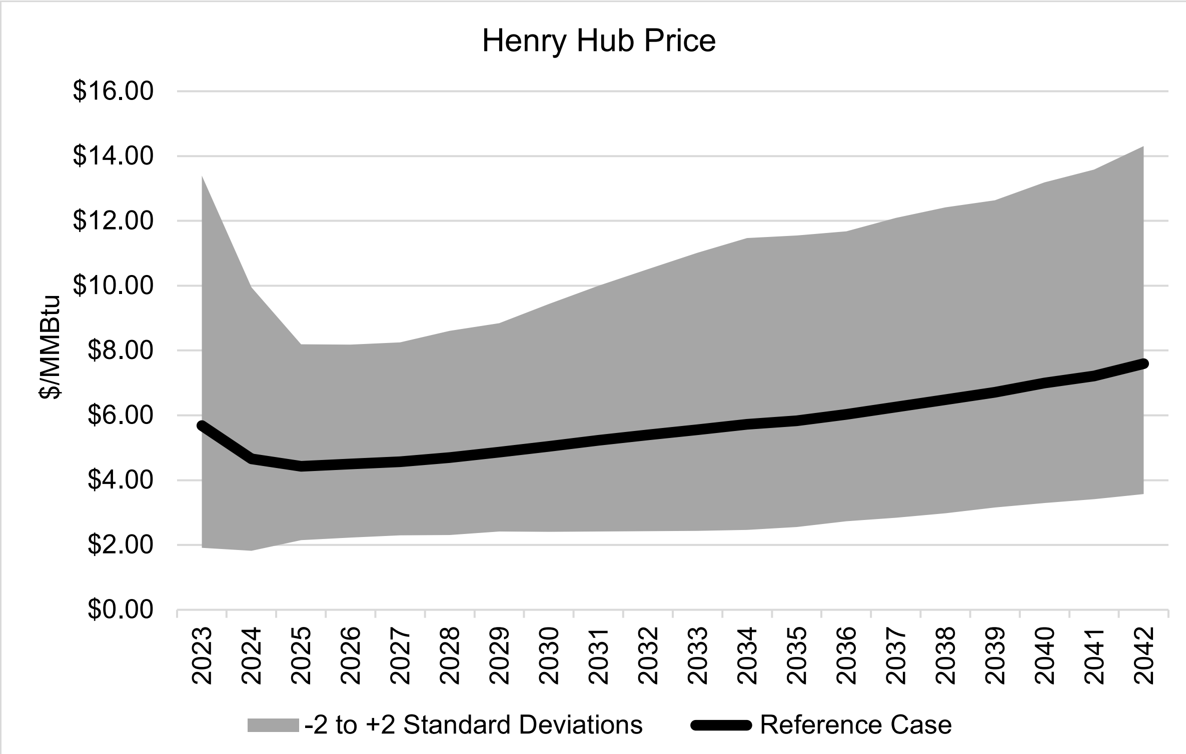
Figure 11.37 –CEI South Load Distribution (Megawatts)



11.6.2 Natural Gas Price Uncertainty

To define the uncertainty around natural gas prices to be used in the stochastic modeling, 1898 & Co. relied on the base, high and low Henry Hub natural gas price forecast from CEI South's price forecast vendor ABB. Specifically, 1898 & Co. developed monthly standard deviations from the base, high and low forecasts, divided the result by the base price forecast to arrive at a percent standard deviation. The monthly percent standard deviations were then applied to the consensus Reference Case pricing to impute monthly lognormal probability distribution for natural gas pricing, which were in turn used in the stochastic modeling that developed the 200 sets of stochastic inputs.

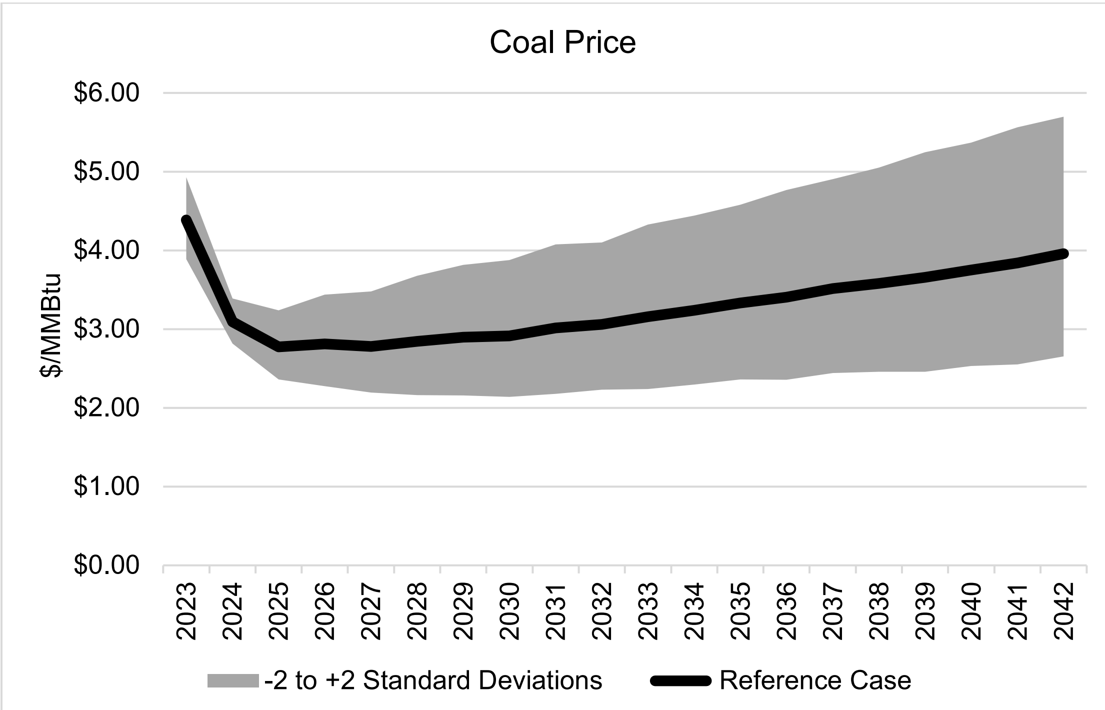
Figure 11.38 –Natural Gas (Henry Hub) Price Distribution (Nominal$/MMBtu)



11.6.3 Coal Price Uncertainty

To define the uncertainty around coal prices to be used in the stochastic modeling, 1898 & Co. relied on the base, high and low coal price forecasts from CEI SOUTH's price forecast vendor ABB. Specifically, 1898 & Co. developed monthly standard deviations from the base, high and low forecasts, divided the result by the base price forecast to arrive at a percent standard deviation. The monthly percent standard deviations were then applied to the consensus Reference Case pricing to impute monthly lognormal probability distribution for coal pricing, which were in turn used in the stochastic modeling that developed the 200 sets of stochastic inputs.

Figure 11.39 –Coal Price Distribution (Nominal$/MMBtu)



11.6.4 CO_2 Emissions Price Uncertainty

No CO_2 emissions prices are assumed for the Reference Case, rather CO_2 prices are assumed for the High Regulatory and Decarbonization/Electrification scenarios. Because of these assumptions, CO_2 price uncertainty is assigned on a discrete basis. Specifically, 1898 & Co. assigned a zero price for CO_2 for the first 120 iterations out of the 200 iterations of stochastic inputs. The next 40 iterations were assigned the CO_2 price from the Decarbonization/Electrification scenario. The last 40 iterations were assigned the highest case CO_2 prices, which are those from the High Regulatory scenario.

11.6.5 Capital Cost Uncertainty

1898 & Co. developed base, high and low solar, wind and storage resource capital costs for use in the scenario analyses. The base forecast for renewable capital costs were developed using the average price for purchase options received in the All-Source RFP.

The proposals reflect up to date near term renewable purchase options and were forecasted through the study period using capital cost estimates from the NREL. The low forecast follows the same methodology for development; however, the lowest purchase price was used as the starting point for the forecast. Finally, the high forecast begins from the highest renewable purchase option price and continues through the study period at the assumed escalation rate (2.3%).

The base, high and low capital costs were developed based on fundamental assumptions and do not conform to a specific probability distribution type. As a result, the renewables capital costs were not included in the stochastics analysis performed in EnCompass for natural gas prices, coal prices and peak demand. Instead, the base, high and low renewables capital costs were treated as discreet distributions and assigned to the 200 iterations for inclusion with the other stochastically develop input variables. The low capital costs were assigned to the first 50 iterations of stochastic variables. The base, or Reference Case capital costs were assigned to the next 100 iterations. The high capital costs were assigned to the final 50 iterations. Because it is unlikely capital costs would stay high or low for every year of the study period, the order of iterations was randomly shuffled every four years prior to the 50/100/50 iteration assignments. With this approach, any one iteration would have a combination of base, high and low capital costs in four-year segments.

Figure 11.40 – Solar Capital Costs Alternate Scenarios (100 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2022	$1,943	$1,700	$2,057	$1,172
2023	$1,943	$1,700	$2,057	$1,149
2024	$1,943	$1,700	$2,057	$1,125
2025	$1,943	$1,700	$2,057	$1,100
2026	$1,943	$1,700	$2,057	$1,073
2027	$1,891	$1,663	$2,104	$1,044
2028	$1,836	$1,626	$2,152	$1,014
2029	$1,777	$1,589	$2,201	$981
2030	$1,714	$1,552	$2,252	$946
2031	$1,737	$1,515	$2,303	$959
2032	$1,761	$1,478	$2,356	$973
2033	$1,785	$1,442	$2,410	$986
2034	$1,809	$1,405	$2,465	$999
2035	$1,834	$1,368	$2,522	$1,013
2036	$1,858	$1,331	$2,580	$1,026
2037	$1,883	$1,294	$2,639	$1,040
2038	$1,908	$1,257	$2,699	$1,054
2039	$1,933	$1,220	$2,761	$1,067
2040	$1,958	$1,183	$2,825	$1,081
2041	$1,983	$1,146	$2,889	$1,095
2042	$2,009	$1,109	$2,956	$1,109

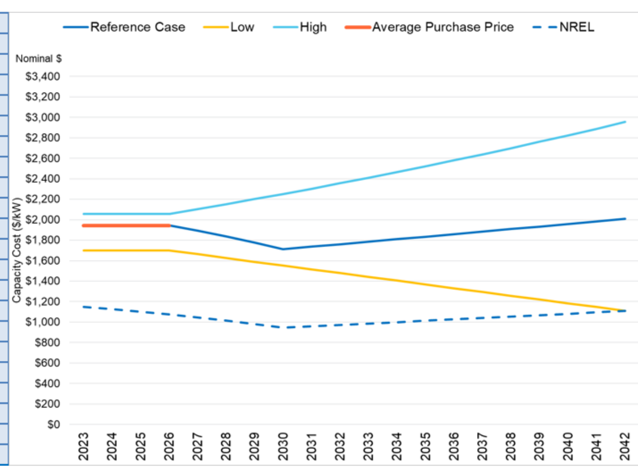


Figure 11.41– Wind Capital Costs Alternate Scenarios (200 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2022	$2,314	$2,100	$2,314	$1,423
2023	$2,314	$2,100	$2,314	$1,400
2024	$2,314	$2,100	$2,314	$1,377
2025	$2,314	$2,100	$2,314	$1,351
2026	$2,314	$2,100	$2,314	$1,325
2027	$2,265	$2,055	$2,367	$1,297
2028	$2,212	$2,011	$2,421	$1,266
2029	$2,155	$1,966	$2,477	$1,234
2030	$2,095	$1,921	$2,533	$1,199
2031	$2,121	$1,877	$2,592	$1,214
2032	$2,148	$1,832	$2,651	$1,230
2033	$2,175	$1,787	$2,712	$1,245
2034	$2,202	$1,743	$2,774	$1,260
2035	$2,229	$1,698	$2,837	$1,276
2036	$2,256	$1,653	$2,903	$1,291
2037	$2,283	$1,609	$2,969	$1,307
2038	$2,310	$1,564	$3,037	$1,323
2039	$2,337	$1,519	$3,107	$1,338
2040	$2,365	$1,474	$3,178	$1,354
2041	$2,392	$1,430	$3,251	$1,369
2042	$2,419	$1,385	$3,325	$1,385

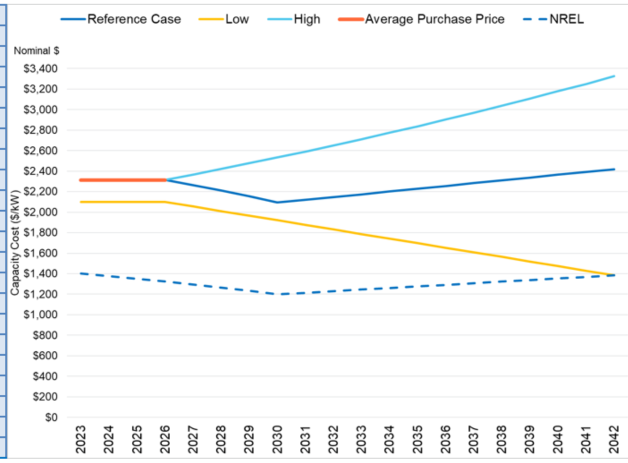
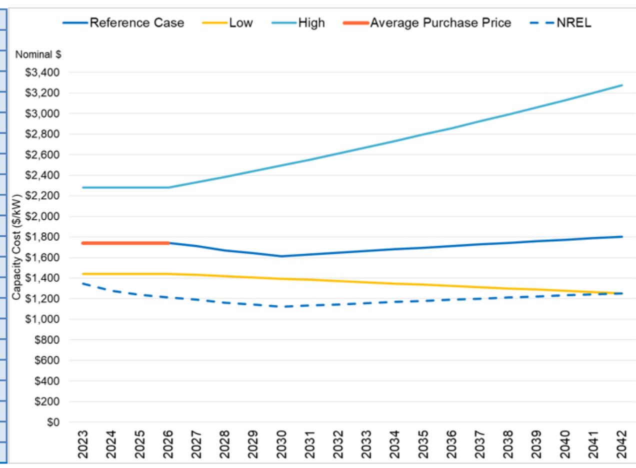


Figure 11.42– Lithium-Ion 50 MW/ 200 MWh Battery Storage Capital Costs Alternate Scenarios ($/kW)

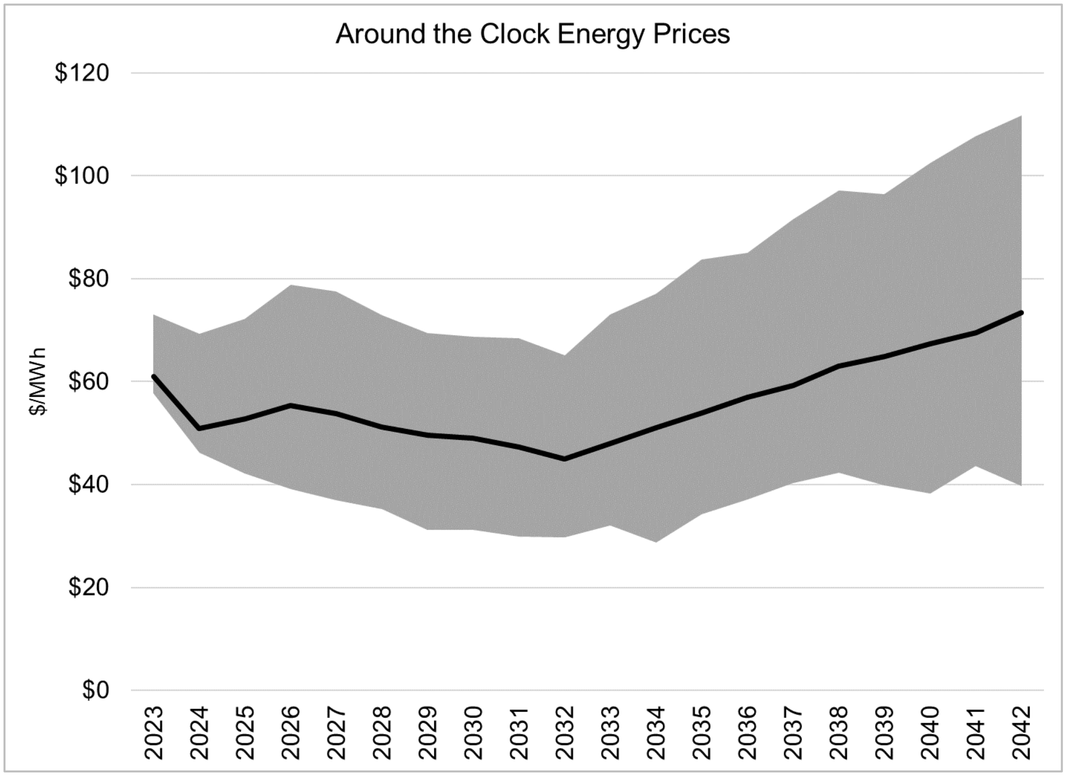
Year	Reference Case	Low	High	NREL
2022	$1,742	$1,443	$2,279	$1,434
2023	$1,742	$1,443	$2,279	$1,344
2024	$1,742	$1,443	$2,279	$1,277
2025	$1,742	$1,443	$2,279	$1,236
2026	$1,742	$1,443	$2,279	$1,211
2027	$1,711	$1,431	$2,331	$1,190
2028	$1,669	$1,419	$2,385	$1,160
2029	$1,643	$1,407	$2,439	$1,142
2030	$1,614	$1,395	$2,495	$1,122
2031	$1,632	$1,383	$2,553	$1,134
2032	$1,648	$1,372	$2,611	$1,146
2033	$1,664	$1,360	$2,671	$1,157
2034	$1,680	$1,348	$2,732	$1,168
2035	$1,696	$1,336	$2,795	$1,179
2036	$1,712	$1,324	$2,859	$1,190
2037	$1,727	$1,312	$2,924	$1,201
2038	$1,743	$1,300	$2,991	$1,212
2039	$1,758	$1,289	$3,060	$1,222
2040	$1,773	$1,277	$3,130	$1,233
2041	$1,788	$1,265	$3,202	$1,243
2042	$1,802	$1,253	$3,275	$1,253



11.6.6 Energy Price Distribution

1898 & Co. updated energy prices that were input into EnCompass for each of the 200 draws. 1898 & Co. used the national database licensed from Horizon Energy, LLC as the starting point for creating the energy prices. Using the different IRP scenarios, unique energy prices forecasts were developed. The energy prices and associated natural gas prices from the scenario model runs were used to develop monthly implied market heat rate curves. These monthly implied market heat rates were applied to monthly natural gas price for the 200 iterations to arrive at monthly energy prices for each iteration.

Figure 11.43 –Stochastic Inputs – Energy Prices – Market Forecast



11.6.7 Affordability Ranking

Figure 11.44– Probabilistic 20-Year Mean NPV $ Million[82]

Portfolio	20 Year NPVRR ($M)	Cents/kWh Delivered	% Above Reference Case
Reference Case	$4,214	6.52	100.0%
F-Class CT	$4,499	6.96	106.7%
Convert F.B. Culley 3 to Natural Gas by 2027	$4,503	6.96	106.8%
Convert F.B. Culley 3 to Natural Gas by 2030	$4,508	6.97	107.0%
Replace FB Culley 3 with Storage and Solar	$4,539	7.02	107.7%
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	$4,559	7.05	108.2%
Replace FB Culley 3 with Storage and Wind	$4,580	7.08	108.7%
Business as Usual	$4,581	7.08	108.7%
Diversified Renewables	$4,583	7.09	108.8%
Diversified Renewables (Early Storage & DG Solar)	$4,676	7.23	111.0%

11.7 TRANSMISSION APPENDIX

11.7.1 Transmission and Distribution Planning Criteria

CEI South continually assesses the performance of its electric transmission and distribution systems to ensure safe and reliable service for its customers. The primary goals of CEI South's planning process can be summarized as follows:

a) Developing a transmission system capable of delivering voltage of constant magnitude, duration and frequency at levels which meet CEI South customers' needs during normal conditions and during a system contingency or set of contingencies;

b) Minimizing thermal loadings on transmission facilities to be within operating limits during normal conditions and to be within emergency limits during contingency conditions;

[82] The energy delivered is a 20-year present value of the Energy Requirement discounted at 5.71 percent, rather than a total sum. This reflects a levelized net present value calculation for the cost per delivered kWh.

c) Analyzing the dynamic stability of the transmission system under various contingency conditions;
d) Ensuring the fault current duty imposed on circuit breakers does not exceed the interrupting capability established by the equipment manufacturer;
e) Optimizing the system configuration such that costs (capital and operating) are minimized while maintaining reliability and providing a plan for system upgrades to meet performance requirements;
f) Coordinating transmission planning activities in broader regional evaluations with the MISO, ReliabilityFirst ("RF") and neighboring transmission owners;
g) Performing an annual assessment of the electric transmission system over a ten-year planning horizon;
h) Performing analysis of reactive power resources to ensure adequate reserves exist and are available to meet system performance criteria;
i) Analyzing the performance of its distribution system to ensure reliability, adequacy to meet future load growth and to address age and condition of existing facilities; and
j) Ensuring compliance with FERC, NERC and RF Reliability Standards for transmission planning.

11.7.2 MISO Regional Transmission Planning

MISO performs the NERC functional role of Planning Coordinator on behalf of CEI South. In its NERC functional role of Transmission Planner, CEI South supports MISO's regional transmission planning processes.

MISO develops regional transmission models that are used for a variety of near-term and long-term planning studies. On an annual basis, MISO builds models to represent a 10-year planning horizon. The modeling process begins in September and concludes the following August. CEI South is responsible for submitting the required modeling data to MISO pursuant to NERC MOD-032.

CEI South participates in MISO coordinated Seasonal Transmission Assessments ("CSA") for spring, summer, fall and winter peak loads as applicable. MISO's Seasonal Assessments review projected demand and resources for the MISO footprint and assess adequacies and risks for upcoming seasons. The CSAs consider planned and unplanned generation and transmission outages. CEI South also participates in MISO Generator Interconnection and Transmission Service Requests planning processes as required.

CEI South participates in MISO's regional Transmission Expansion Plan ("MTEP"). The system expansion plans produced through the MTEP process ensure the reliable operation of the transmission system, support achievement of state and federal energy policy requirements and enable a competitive electricity market to benefit all customers. The planning process, in conjunction with an inclusive, transparent stakeholder process, identifies and supports development of transmission infrastructure that is sufficiently robust to meet local and regional reliability standards, enables competition among wholesale capacity and energy suppliers in the MISO markets and allows for competition among transmission developers in the assignment of transmission projects.

MISO approved a 345kV Market Efficiency Project between CEI South's Duff substation and Big Rivers Electric Corporation's Coleman EHV substation during the MTEP 2015 planning cycle. The project was completed and placed into -service in late 2020. Pursuant to FERC Order 1000, MISO solicited competitive bids to construct the 345kV line. CEI South partnered with PSEG in submitting a proposal to MISO to construct the line; however, the project was awarded to Republic Transmission, LLC. CEI South, as the incumbent transmission owner, was responsible for the Duff substation modifications required for the project. The overall project cost was shared according to MISO's Tariff. The project not only provided regional economic benefits, but also enhanced grid reliability in the area of CEI South's Newtonville substation.

11.7.3 Transmission Assessment

CEI South's most recent transmission assessment was completed in 2019. The study used the final Multiregional Modeling Working Group ("MMWG") 2018 Series Models, which includes the CEI South full detailed model. The MMWG is responsible for developing a library of solved power flow models and associated dynamics simulation models of the Eastern Interconnection. The models are used by the NERC Regions and their member systems in planning future performance and evaluating current operating conditions of the interconnected bulk electric systems. Siemens PTI PSS/E version 33.11 software was used to conduct the assessment.

CEI South's internal planning procedures direct the specific tasks and methods for conducting this study. The internal procedures also define the ratings methodology used for the existing and proposed facilities. All simulations were performed using Steady State Power Flow models using AC analysis. Models were solved using the Fixed Slope Decoupled Newton-Raphson ("FDNS") solution method with stepping transformer tap adjustments, switched shunts enabled, area interchange control enabled for tie lines and loads, DC taps disabled and VAR limits applied automatically. Dynamic simulations were not completed in 2019, as previous dynamic studies were still deemed valid. Dynamic simulations were completed with MTEP-19.

The CEI South Bulk Electrical System (100kV and above) is expected to be stable and perform well through 2029. Normal system conditions do not result in any voltage problems or thermally overloaded facilities. Some facility outage contingencies create thermal overloads and voltage violations. When these violations cannot be effectively mitigated by operational guides, CEI South plans projects to mitigate the violations.

CEI South recently completed a new 138kV line from Toyota South substation to Scott Township substation which provides a key customer improved reliability. Prior to this new line, the loss of the existing two 138kV lines (both from Francisco substation) into Toyota substation resulted in the loss of service to the Toyota manufacturing facility. This line also serves as a second line into Scott Township substation, which was on a radial 138kV line. Scott Township substation provides voltage support for most of the load along the Highway 41 North corridor. This new line is also a parallel path to the Francisco to Elliott 138kV line and increases post-contingent import capability.

As previously mentioned, the new 138kV East/West line from AB Brown station to Pigeon Creek to Warrick North station also provides several key benefits to the transmission system. This line was completed and put into service in February 2023. Overall benefits include a reduced power flow on the 69kV system, improved import capability from the 345kV system, better flexibility on 138kV outages, and system support for future generation changes.

The only mentionable extreme contingency is for the complete loss of the A.B. Brown 138kV substation. This substation loss has the potential to cause voltage loss to the Mt. Vernon area and numerous large industrial customers. NERC requirements do not require that CEI South prevent this event. The standards only require that extreme contingencies not cause cascading outage and impair the Bulk Electric System (“BES”). The electric transmission system outside of Mt. Vernon is not affected; however, an outage of this magnitude would require a notification to NERC.

Several 69kV lines were recently completed as alternate feeds to reduce outage times.

- A new 69kV line installed between Boonville and Boonville Pioneer Substation (placed in-service in 2021).
- A new 69kV line installed as a second source to Paradise distribution substation (placed in-service in 2021)

These are not NERC reliability driven projects but should reduce outage durations to customers caused by transmission outages in these areas and should improve reliability indices and metrics.

Several new substations will be completed in 2023 to account for additional residential and industrial load growth. Anderson Road is a new distribution substation recently installed to meet residential load growth. There are also plans to add additional power transformers at existing distribution substations to support load growth and facilitate 4kV to 12kV conversion projects. Darlington Road is a 138kV transmission station installed to support approximately 80MW for Kaiser Aluminum with two dedicated 138kV feeders.

SECTION 12
TECHNICAL APPENDIX ATTACHMENTS

Attachment 1.1 Non-Technical Summary

Attachment 1.2 CEI South Technology Assessment Summary Table

Attachment 3.1 Stakeholder Materials

Attachment 4.1 2022/2023 CEI South Long-Term Electric Energy and Demand Forecast Report

Attachment 4.2 CEI South Hourly System Load Data

Attachment 4.3 2023-2024 MISO LOLE Study Report

Attachment 4.4 Confidential Long-Term Electric Energy and Demand Input/Output files

Attachment 6.1 CEI South Electric 2021-2023 DSM Plan

Attachment 6.2 2022 DSM Market Potential Study

Attachment 6.3 All-Source RFP

Attachment 6.5 Conversion Studies (CT conversion, FB Culley Conversion, and Cogen)

Attachment 6.6 ACE Rule Heat Rate Study

Attachment 8.1 Balance of Loads and Resources

Attachment 8.2 Confidential EnCompass Input/Output Model Files