BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 106
NIPSCO 2025 Rate Order

ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Bennett	√		
Freeman	√		
Veleta	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RETAIL RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS (BOTH EXISTING AND NEW); (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING, BUT LIMITED TO, AUTHORITY TO CAPITALIZE AS RATE BASE ALL EXPENDITURES FOR IMPROVEMENTS TO PETITIONER'S INFORMATION TECHNOLOGY SYSTEMS THROUGH THE DESIGN, DEVELOPMENT, AND IMPLEMENTATION OF A WORK AND ASSET MANAGEMENT ("WAM") PROGRAM; AND (5) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE PARTIAL WAIVER OF 170 IAC 4-1-16(f) AND PROPOSED REMOTE DISCONNECTION AND RECONNECTION PROCESS AND, TO THE EXTENT NECESSARY, IMPLEMENTATION OF A LOW INCOME PROGRAM.	**)** **)** **)** **)** **)** **)** **)** **)** **)** **)** **)** **)** **)** **)** **)** **)** **)**	**CAUSE NO. 46120** **APPROVED: JUN 26 2025**

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Chairman
Loraine L. Seyfried, Chief Administrative Law Judge

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On September 12, 2024, Northern Indiana Public Service Company LLC ("NIPSCO" or "Petitioner") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") seeking authority to increase its rates and charges for electric utility service and associated relief as discussed below.[1] On that same day, Petitioner filed its case-in-chief, workpapers, and the information listed in the minimum standard filing requirements set forth at 170 IAC 1-5. NIPSCO's case-in-chief included testimony, attachments, and workpapers from the following witnesses:[2]

- Vincent A. Parisi, President and Chief Operating Officer, NIPSCO;
- Erin E. Whitehead, Vice President of Regulatory Policy and Major Accounts, NIPSCO;
- Richard D. Weatherford, Manager, Regulatory – Rate Case Execution, NiSource Corporate Services Company ("NCSC");
- Emily J. Bytnar, Manager of Rate Case Execution, NCSC;
- Nick Bly, Director of Accounting, NCSC;
- Patrick L. Baryenbruch, President, Baryenbruch & Company, LLC;
- Orville Cocking, Senior Vice President of Electric Operations, NIPSCO;
- Stephen Holcomb, Director of Environmental Policy & Sustainability, NCSC;
- Rosalva Robles, Manager of Planning – Regulatory Support, NIPSCO;
- Kirstie Eyre, Compensation Manager, NCSC;
- John J. Spanos, President, Gannett Fleming Valuation and Rate Consultants, LLC;
- Vincent V. Rea, Managing Director, Regulatory Finance Associates, LLC;
- Jennifer A. Harding, Vice President of Tax, NCSC;[3]
- Melissa Bartos, Senior Vice President, Concentric Energy Advisors ("Concentric");
- John D. Taylor, Managing Partner, Atrium Economics, LLC ("Atrium"); and
- Candice Lash, Lead Regulatory Studies Analyst, NCSC.

As part of its requested relief, NIPSCO sought approval of an Alternative Regulatory Plan ("ARP") pursuant to Ind. Code § 8-1-2.5-6 to partially waive 170 IAC 4-1-16(f) and to approve Petitioner's proposed remote disconnection and reconnection process, and to the extent necessary to implement a low income program.

Petitions to Intervene were filed by United States Steel Corporation ("U.S. Steel"); NLMK Indiana, a division of NLMK USA ("NLMK"); NIPSCO Industrial Group ("Industrial Group");[4] Walmart Inc. ("Walmart"); Citizens Action Coalition of Indiana, Inc. ("CAC"); RV Industry

[1] On August 13, 2024, NIPSCO provided its notice of intent to file a rate case in accordance with the Commission's General Administrative Order 2013-5. Petitioner's Exhibit 1, Attachment 1-B.

[2] NIPSCO filed corrections or revisions to its case-in-chief on November 26, 2024, December 18, 2024, December 30, 2024, January 27, 2025, and February 6, 2025. NIPSCO also late-filed Attachments 1-C and 1-D (consisting of the Proofs of Legal Notice Publication and Customer Notice) to Mr. Parisi's testimony on January 20, 2025. NIPSCO originally filed the Verified Direct Testimony of Gregory Skinner, Vice President of IT Utilities Systems, NCSC that was not offered into evidence.

[3] NIPSCO initially filed the Verified Direct Testimony of Jonathan Bass, Director of Income Tax Planning & Controversy, NCSC.

[4] The companies that comprise the Industrial Group are BP Products North America, Inc., Cleveland-Cliffs Steel LLC, Linde, Marathon, and USG.

User's Group ("RV Group");[5] United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union AFL-CIO/CLC and its Locals 12775 and 13796 ("USW"); and Board of County Commissioners of LaPorte County, Indiana ("LaPorte County"). These petitions were granted without objection. The Indiana Office of Utility Consumer Counselor ("OUCC") also participated as a party.

Pursuant to Ind. Code § 8-1-2-61(b), public field hearings were held in Valparaiso, Indiana on November 26, 2024; in Hammond, Indiana on December 5, 2024; and in Gary, Indiana on December 5, 2024. Members of the public presented testimony at each of these hearings.

On December 19, 2024, the OUCC and certain intervenors filed their respective cases-in-chief. For purposes of its case-in-chief, the OUCC prefiled written consumer comments and testimony and attachments from the following witnesses:[6]

- Michael D. Eckert, Chief Technical Advisor, OUCC Electric Division;
- Brian R. Latham, Utility Analyst, OUCC Electric Division;
- Kaleb G. Lantrip, Utility Analyst, OUCC Electric Division;
- Brittany L. Baker, Utility Analyst, OUCC Electric Division;
- Brian A. Wright, Utility Analyst II, OUCC Electric Division;
- Roopali Sanka, Utility Analyst, OUCC Electric Division;
- Gregory L. Krieger, Utility Analyst, OUCC Electric Division;
- Leja D. Courter, Chief Technical Advisor, OUCC;
- John W. Hanks, Utility Analyst, OUCC Electric Division;
- April M. Paronish, Assistant Director, OUCC Electric Division; and
- Michael W. Deupree, a consultant with Acadian Consulting Group.

The OUCC also included with its pre-filed evidence written consumer comments pertaining to the relief requested in NIPSCO's Petition as Public's Exhibit No. 13. On December 30, 2024, and pursuant to a docket entry issued the same day, the OUCC late-filed the testimony and attachments of Roxie McCullar, consultant with William Dunkel and Associates.

The Industrial Group prefiled testimony and attachments from James R. Dauphinais and Michael P. Gorman, both Managing Principals with Brubaker & Associates, Inc., and Brian C. Andrews, a Principle with Brubaker & Associates, Inc.[7]

NLMK prefiled testimony and attachments from Jared R. Robertson, Senior Consultant for Energy Strategies, LLC.

Walmart prefiled the testimony and attachments of Lisa V. Perry, Director, Utility Partnerships – Regulatory for Walmart.

[5] The companies that comprise the RV Group are: LCI Industries, Inc., Forest River, Inc., Patrick Industries, Inc., and Thor Industries.
[6] The OUCC filed corrections to its case-in-chief on January 15 and January 31, 2025.
[7] The Industrial Group filed corrections to its case-in-chief on February 7, 2025.

The CAC prefiled the testimony and attachments of Benjamin Inskeep, Program Director for the CAC.[8]

The RV Group prefiled the testimony and attachments of Jeffry Pollock, Energy Advisor and President of J. Pollock, Incorporated and Jonathan W. Burke, Chief Energy Consultant at Tactical Energy Group, Inc.

U.S. Steel prefiled the testimony of Jill A. Schuepbach, a Principal in the Energy Practice of NewGen Strategies and Solutions, LLC for U.S. Steel.

LaPorte County prefiled the testimony and attachments of Connie Gramarossa, Board President of LaPorte County; Melissa Whited, Vice President of Synapse Energy Economics; and Michael R. O'Connell, Principal Consultant for Midwest Energy Consulting LLC.

On January 16, 2025, the Industrial Group prefiled cross-answering testimony of James R. Dauphinais; the CAC prefiled cross-answering testimony of Benjamin Inskeep; the RV Group prefiled cross-answering testimony of Jeffry Pollock;[9] and NLMK prefiled cross-answering testimony of Jared R. Robertson. On January 17, 2024, U.S. Steel prefiled cross-answering testimony of Jill Schuepbach and on January 23, 2024, the OUCC prefiled the cross-answering testimony of Michael W. Deupree.[10]

NIPSCO prefiled rebuttal testimony, exhibits, and workpapers on January 16, 2025, for the following witnesses:

- Erin E. Whitehead;
- Richard D. Weatherford;
- Nick Bly;
- Orville Cocking;
- John J. Spanos;
- Vincent V. Rea;
- Jennifer A. Harding;
- John D. Taylor;
- Alan Felsenthal, Managing Director, PricewaterhouseCoopers LLP; and
- Karl E. Stanley, Vice President of Supply & Optimization for NiSource, Inc.

On February 7, 2025, a Stipulation and Settlement Agreement ("Settlement" or "Settlement Agreement") was filed by NIPSCO, the OUCC, the Industrial Group, NLMK, U.S. Steel, Walmart, and the RV Group (collectively the "Settling Parties").

On February 7, 2025, NIPSCO prefiled the settlement testimony, attachments, and workpapers of Ms. Whitehead, Mr. Weatherford, and Mr. Taylor in support of the Settlement

[8] The CAC late-filed Attachment BI-4 (consisting of the Field Hearing Transcripts) to Mr. Inskeep's testimony on February 3, 2025.
[9] The RV Group also updated its list of companies to remove Patrick Industries, Inc.
[10] The OUCC filed corrections to its cross-answering testimony on January 31, 2025.

Agreement. Also on February 7, 2025, the following witnesses of the OUCC and other Settling Parties filed additional evidence supporting the Settlement Agreement:

- Brian R. Latham;
- Michael P. Gorman;
- James R. Dauphinais;
- Lisa V. Perry; and
- Jill A. Schuepbach

On February 28, 2025, the CAC filed additional testimony of Mr. Inskeep opposing the Settlement Agreement.

On March 7, 2025, NIPSCO prefiled the settlement reply testimony of Ms. Whitehead and Mr. Taylor, the OUCC prefiled the settlement reply testimony of Mr. Deupree, U.S. Steel prefiled the settlement reply testimony of Ms. Schuepbach,[11] and the Industrial Group prefiled settlement reply testimony of Mr. Dauphinais. Also on March 7, 2025, the RV Group and Walmart filed their Joinder in Settlement Reply Testimony.

An evidentiary hearing was conducted in this Cause at 9:30 a.m. on March 25, 2025, in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the evidentiary hearing, the Settlement Agreement and the direct, cross-answering, rebuttal, settlement, opposing settlement, and settlement reply testimony and exhibits of each party as well as certain stipulations in lieu of cross-examination were offered and admitted into the record without objection.

The Commission, based upon applicable law and the evidence, finds as follows:

1. Notice and Jurisdiction. Legal and timely notice of the public hearings held in this Cause was given and published as required by law. NIPSCO is a public utility as defined in Ind. Code § 8-1-2-1(a) and an "energy utility" as that term is defined in Ind. Code § 8-1-2.5-2. NIPSCO is subject to the Commission's jurisdiction for approval of its rates and charges for electric utility service under Ind. Code §§ 8-1-2-42 and -42.7. NIPSCO has also elected to become subject to Ind. Code § 8-1-2.5-6. NIPSCO caused to be published the filing of its Petition pursuant to Ind. Code §§ 8-1-2-61 and 8-1-2.5-6 and mailed notice to its customers as required by 170 IAC 4-1-18(C). The Commission has jurisdiction over NIPSCO and the subject matter of this proceeding.

2. Petitioner's Organization and Business. NIPSCO is a public utility with its principal place of business located at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO renders retail electric utility service to more than 487,000 retail customers located in all or part of the following Indiana counties: Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, Saint Joseph, Starke, Steuben, Warren, and White. Additionally, NIPSCO is subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC") and is a member of Midcontinent Independent System Operator, Inc. ("MISO"), a regional transmission organization operated under FERC's authority

[11] U.S. Steel prefiled corrections to Ms. Schuepbach's testimony on March 17, 2025.

that controls the use of NIPSCO's transmission system and the dispatching of NIPSCO's generating units.

NIPSCO owns, operates, manages, and controls electric generating, transmission, and distribution plant and equipment and related facilities, which are used and useful for the convenience of the public in the production, transmission, distribution, and furnishing of electric energy, heat, light, and power to the public. NIPSCO classifies its property in accordance with the Uniform System of Accounts as prescribed by FERC and approved and adopted by the Commission.

3. Existing Rates. The Commission approved NIPSCO's current electric basic rates and charges in its August 2, 2023 Order in Cause No. 45772 ("45772 Order"). The petition initiating Cause No. 45772 was filed with the Commission on September 19, 2022; therefore, in accordance with Ind. Code § 8-1-2-42(a), it has been more than 15 months since NIPSCO filed its most recent petition for an increase in basic rates and charges and the filing of NIPSCO's Petition in this Cause.

In the 45772 Order, the Commission approved a Stipulation and Settlement Agreement ("45772 Settlement") which included a Stipulation and Settlement Agreement between NIPSCO and its industrial customers on Rate 831/531[12] implementation (the "Rate 831/531 Modification Settlement").[13]

4. Test Year and Rate Base Cutoff. As authorized by Ind. Code § 8-1-2-42.7(d)(1), NIPSCO proposed a forward-looking test period using projected data, with the test year used for determining projected operating revenues, expenses, and net operating income being the 12-month period ending December 31, 2025 ("Forward Test Year"). NIPSCO is utilizing the test year end, December 31, 2025, as the general rate base cutoff date. The historical base period is the 12-month period ending December 31, 2023.

In its Petition, NIPSCO proposed a two-phase rate implementation, with potential interim phases, to reasonably reflect actual rate base, including the utility property that is used and useful at the time rates are placed into effect. Base rates would be implemented in two steps, with the first step following issuance of an Order in this Cause and based upon the actual rate base and capital structure using a general rate base cutoff of May 31, 2025 (Step 1). The second step would take place following the close of the test year, based upon actual rate base and capital structure as of December 31, 2025 (Step 2).

NIPSCO proposed up to two additional steps for two "major projects" (as that term is defined in 170 IAC 1-5-1(l)). The two major projects are the Fairbanks Solar Generating Facility ("Fairbanks") and the Gibson Solar Generating Facility ("Gibson"). Each project is expected to cost greater than 1% of NIPSCO's projected net original cost rate base. A certificate of public convenience and necessity ("CPCN") was issued for Fairbanks originally in Cause No. 45511 and

[12] Rate 831 is the tariff rate approved for NIPSCO's large industrial customers in Cause No. 45159, which was later updated to Rate 531 in Cause No. 45772 and is being updated in this case to Rate 631.

[13] The Rate 831/531 Modification Settlement was entered into on September 12, 2022 by and between NIPSCO, Cleveland-Cliffs Steel LLC, Linde, Inc., BP Products North America, Inc., Cargill, Inc., NLMK Indiana, Pratt Paper (IN), LLC, and US Steel.

revised in Cause No. 46028. A CPCN was issued for Gibson originally in Cause No. 45926 and revised in Cause No. 46032. Fairbanks is expected to be in service by the Phase 1 general rate base cutoff and Gibson to be in service by July 31, 2025. NIPSCO proposed additional steps for these two projects to the extent they are not in service by May 31, 2025 by adjusting rates to reflect return (using the capital structure as of May 31, 2025) and depreciation rates reflected in the underlying Order issuing the CPCN. To the extent the projects are not in service by May 31, 2025 but are in service by the time Phase 1 rates are implemented, NIPSCO proposed to include the interim step in the Phase 1 implementation. NIPSCO was granted a waiver of the monthly investment reporting requirement set forth in 170 IAC 1-5-5(5)(D) but was required to declare major projects used and useful in accordance with 170 IAC 1-5-5.

5. NIPSCO's Requested Relief. NIPSCO seeks approval of changes to its basic rates and charges for electric utility service and associated accounting relief to provide NIPSCO with the opportunity to recover its ongoing costs of providing electric utility service and earn a fair return on the fair value of its property.

6. Opposition, Rebuttal, and Cross-Answering. The OUCC and intervenors raised numerous challenges to NIPSCO's filing, including, but not limited to, challenging rate base, rate of return, operation and maintenance ("O&M") expenses, depreciation rates, cost of service allocation, and rate design. The extent to which these parties disagreed with each other is reflected in their cross-answering testimony. The extent to which NIPSCO disagreed or agreed with the OUCC and intervenors was addressed in NIPSCO's rebuttal evidence.

7. Settlement Agreement and Supporting Testimony. The Settling Parties' witnesses presented testimony in support of the Settlement Agreement. They discussed the terms of the Settlement Agreement and explained how the Settlement Agreement resolves all issues presented in the case in a fair and reasonable manner, including issues related to the revenue requirement, cost of service, rate design, and cost allocation. The terms of the Settlement Agreement specifically state that it is a settlement of all issues among the Settling Parties in this Cause. In addition to the Settling Parties, LaPorte County and the USW agreed not to oppose the Settlement.

The Settling Parties' witnesses conveyed that the Settlement Agreement is a product of a diligent effort by all the Settling Parties to reach a comprehensive result. The complexity of the issues and the diverse interests of the Settling Parties dictated the need for compromise on the part of each party involved, and the Settlement Agreement, taken as a total package, reflects a delicate balance that the Settling Parties agree reasonably accommodates their interests.

Ms. Whitehead testified the Settlement is comprehensive in scope and proposes to fairly resolve all issues in dispute. She testified that it provides NIPSCO with an increase in rate revenue sufficient to enable it to meet its revenue requirement, including providing an opportunity to earn an adequate return on the investments made to serve its customers. She stated that after much compromise, NIPSCO agreed to a $111,616,865, or 30.28%, reduction from the increase requested in its case-in-chief.

According to Mr. Latham, if approved, the Settlement will provide certainty regarding critical issues that would have otherwise remained contested and reasonably resolves them. The

resolved issues include revenue requirements, authorized return, a proposed low income opt-out program, a proposed new multi-family rate class, and the allocation of NIPSCO's revenue requirement among its various rate classes. He explained that the Settlement is the product of intense negotiations, with each party making informed decisions and/or compromises regarding challenging issues and assessing the litigation risks. He said that while the Settlement represents a balancing of interests, the OUCC, as the statutory representative of NIPSCO's ratepayers, concluded the Settlement is a fair resolution, is within the range of outcomes supported by the case's evidence, and should be approved. He noted considerable effort was expended over multiple weeks in balancing the interests of customers and NIPSCO while engaging in arm's length negotiations.

Ms. Schuepbach testified that the Settlement terms represent an equitable compromise among the Settling Parties in this proceeding. Further, she explained that the terms agreed upon in the Settlement will keep NIPSCO profitable and will allow U.S. Steel to remain a customer on the NIPSCO system. She said that other customer classes benefit as well because of reductions in the overall system revenue requirement and the settlement class revenue allocators. She said the Settling Parties worked hard to agree on an outcome that represented the best possible result for each customer class and NIPSCO.

Ms. Perry asserted that the Settlement represents significant compromise among parties with diverse interests based on the evidence presented on the complex issues in this case. She maintained that the Settlement will produce an opportunity for NIPSCO to earn sufficient revenues to provide adequate service to its customers at a fair return while preserving customers' interests in safe and reliable service and reasonable rates.

Mr. Gorman testified the Settlement was the product of arm's length negotiations conducted in good faith by a range of parties with diverse interests represented by competent counsel, and subsequent to the presentation of their positions in evidentiary filings and discovery. Noting the case raised a number of issues on a variety of subjects, he said the Settling Parties were nevertheless able to achieve consensus on the terms of a comprehensive Settlement. In Mr. Gorman's opinion, the Settlement, taken as a total package, is a reasonable resolution that appropriately balances the various interests of the Settling Parties in a manner consistent with sound ratemaking principles.

Mr. Dauphinais testified that, as a total package, the Settlement resolves all of the issues in this complex proceeding on terms that are supported by the record, falls within the range of litigation positions put forward by the parties, and reflects reasonable compromises on the disputed issues. He expressed his belief that the cost of service and rate design terms operate in conjunction with the revenue terms to produce rates that are just and reasonable for all classes. He said each term is integral to the overall reasonableness of the Settlement.

A. <u>Settlement Overview</u>. Ms. Whitehead explained that the specific objectives addressed in the Settlement are to establish a level of basic rates and charges for NIPSCO which are calculated to provide the opportunity to earn a fair return on the fair value of its plant and equipment.

Ms. Whitehead noted the Settling Parties have agreed that NIPSCO's base rates will be designed to produce gross revenue at proposed rates of $2,086,642,669, resulting in a proposed authorized net operating income of $651,868,680. Ms. Whitehead also supported the Settlement Agreement's stipulated return on equity ("ROE") of 9.75%. Mr. Weatherford explained that under the Settlement Agreement, the total increase in base rates results in a revenue increase from current base rates of $257,043,752. The stipulated revenue requirement under the Settlement results in a reduction of $111,616,865 from the amount NIPSCO originally requested in its case-in-chief. Mr. Weatherford presented all the settlement adjustments in his settlement testimony.

Mr. Latham explained that under the Settlement, NIPSCO's originally requested revenue increase is significantly reduced by agreement upon a lower revenue requirement amount and through rate design, thereby furthering affordability. Additionally, NIPSCO's residential customer charge remains unchanged at $14 in response to the many ratepayers who voiced opposition to NIPSCO's proposed increase in this charge.

As shown in Petitioner's Exhibit 2-S, Attachment 2-S-A, NIPSCO estimates that residential bills for the average customer consuming 672 kilowatts per hour ("kWh") would increase approximately 16.75% following Step 2 rate implementation, including anticipated changes in NIPSCO trackers. Ms. Whitehead testified that under NIPSCO's case-in-chief, residential customers would have received a 22.01% increase following Step 2 rate implementation, based on an average residential customer usage of 729 kWh. She noted that combining the multi-family rate (proposed Rate 615) into Rate 611 results in lower average overall residential customer consumption, which makes comparing these average residential bill impacts challenging.

B. <u>Revenue Requirement</u>. The Settlement Agreement provides that NIPSCO's base rates will be designed to produce $2,086,642,669 prior to application of surviving Riders. The increase in base rates results in an increase from current base rates of $257,043,752. The agreed upon revenue requirement reflects the depreciation study and accrual rates and amortization provided in the Settlement Agreement. The stipulated revenue requirement is calculated to produce authorized net operating income of $651,868,680. Mr. Weatherford described the Step 2 revenue requirement and sponsored the supporting schedules.

Mr. Gorman testified that the agreed upon revenue requirement reflects total reductions equal to just under 58% of the total value of the adjustments proposed by the Industrial Group.

C. <u>Original Cost Rate Base, Capital Structure, and Rate of Return</u>. The Settlement provides that the weighted average cost of capital times NIPSCO's original cost rate base yields a fair return for purposes of this case. Based upon this agreement, the Settlement provides that NIPSCO should be authorized a fair rate of return of 7.14%. The Settlement provides for a projected net original cost rate base at Step 2 of $9,129,813,441. The Settlement also provides for NIPSCO's forecasted capital structure, including its Prepaid Pension Asset and Post-Retirement Liability at zero cost as reflected in NIPSCO's direct and rebuttal testimony, and a stipulated ROE of 9.75%. The Settlement provides for the following forecasted capital structure at Step 2:

	Total Company Capitalization	Cost %	Weighted Average Cost %
Common Equity	$7,718,129,223	9.75%	5.17%
Long-Term Debt	$5,468,979,284	5.20%	1.95%
Customer Deposits	$59,885,295	5.63%	0.02%
Deferred Income Taxes	$1,691,723,532	0.00%	0.00%
Post-Retirement Liability	$(7,491,885)	0.00%	0.00%
Prepaid Pension Asset	$(372,308,313)	0.00%	0.00%
Post-1970 Investment Tax Credit	$174,612	7.87%	0.00%
Totals	**$14,559,091,748**		**7.14%**

In its case-in-chief, NIPSCO proposed a 10.6% ROE and several intervenors, including the OUCC and the Industrial Group, advocated for a considerably lower ROE. The testimony in support of the Settlement Agreement explained that as a result of the negotiations, a compromise was reached between the NIPSCO and intervenor ROE recommendations, resulting in a 9.75% ROE in the Settlement. Ms. Whitehead explained that if NIPSCO's ROE is set too low, it could lead to financial insecurity that would place increased risk on NIPSCO's ability to attract capital, which could also challenge NIPSCO's ability to obtain the capital necessary to continue to provide safe, reliable, and affordable service to its electric customers.

Ms. Whitehead explained that although settlement agreements are not precedential, the Settlement's agreed ROE of 9.75% is slightly lower than or equal to: (1) the negotiated NIPSCO ROE of 9.80% reflected in the settlement approved by the Commission in its 45772 Order; (2) the negotiated AES Indiana ROE of 9.90% approved by the Commission on April 17, 2024 in Cause No. 45911; (3) the negotiated Indiana Michigan Power Company ROE of 9.85% approved by the Commission on May 8, 2024 in Cause No. 45933; (4) the litigated Duke Energy Indiana, LLC ("Duke") ROE of 9.75% approved by the Commission on January 29, 2025 in Cause No. 46038; and (5) the negotiated CenterPoint Energy Indiana South ("CEI South") ROE of 9.8% approved by the Commission on February 3, 2025 in Cause No. 45990. She said for all these reasons, the Settlement Agreement represents a reasonable outcome related to ROE in this proceeding. The Settlement Agreement provides, at Section C.4., that the Agreement "has accounted for the overall level of risk presented to NIPSCO by the Agreement."

Mr. Latham testified the agreed original cost rate base of $9,129,813,441 is lower than the OUCC's recommended rate base of $9,229,256,490 as of December 31, 2025, which reflects the OUCC's recommended $556,951 inventory adjustment NIPSCO accepted in its rebuttal testimony. He explained that the OUCC's case-in-chief recommended a 9.00% cost of equity and that, in the context of the overall settlement, the OUCC considers the agreed 9.75% cost of equity to be a reasonable result. It is within the range of cost of equity evidence presented to the Commission and is a favorable decrease from NIPSCO's currently authorized level, particularly when combined with other compromises made in the Settlement.

Ms. Perry testified she provided numerous concerns with NIPSCO's proposed 10.6% ROE and presented evidence regarding Walmart's perspective on a reasonable authorized return. While the 9.75% ROE set forth in the Settlement may not be as low as Walmart would have advocated

for in litigation, for the purposes of settlement, Walmart believes that a 9.75% ROE provides NIPSCO the opportunity to earn a fair return while still protecting customers' expectations of safe and reliable service at just and reasonable rates.

Mr. Gorman testified that the Industrial Group recommended that NIPSCO's current cost of equity be set in the range of 9.10% to 9.70%, with a point estimate of 9.40%. His analysis was based upon observable market evidence, an assessment of the risk premium associated with market securities, and a general assessment of the market risk associated with investment in regulated utilities. He testified that a further reduction was appropriate to reflect the lower financial risk NIPSCO faces due to its equity rich capital structure to arrive at his recommended ROE of 9.15%. He also conducted an analysis which determined that his recommended ROE would continue to provide NIPSCO with access to adequate capital on reasonable terms. He testified that although 9.75% is higher than his recommended ROE, and slightly outside his recommended range, it is well below the 10.60% to 11.10% range proposed by NIPSCO. Further, the agreed upon ROE is slightly below NIPSCO's current authorized ROE of 9.80%, and below the midpoint between his recommended 9.15% and NIPSCO's requested 10.60% ROE. He stated that, given the totality of the evidence in this case, he considers the 9.75% ROE to be reasonable.

D. Depreciation and Amortization. The Settlement Agreement decreases depreciation expense by $12,270,000 from NIPSCO's case-in-chief filing, which is comprised of a $10,000,000 reduction as a result of reducing decommissioning costs and adjusting originally proposed service lives or net salvage components associated with certain depreciation accrual rates and a $2,270,000 reduction as a result of the $100,000,000 reduction to NIPSCO's case-in-chief projected Transmission & Distribution Rate Base. The proposed depreciation accrual rates by FERC Account that result from these changes are included in Joint Exhibit B to the Settlement.

The Settlement also decreases NIPSCO's amortization expense by $5,556,445 achieved by changing the amortization periods for the transmission, distribution, and storage system improvement charge ("TDSIC") and Electric Rate Case Expense regulatory asset balances from two to four years. NIPSCO will make a compliance filing at the conclusion of all amortization periods to remove the amortization from the revenue requirement, and rates will be adjusted accordingly. Mr. Weatherford explained the $5,556,445 deduction is comprised of a decrease of $4,909,882 for the extended amortization of the TDSIC regulatory asset to now amortize over an additional two-year period through August 2029, which deviates from NIPSCO's originally proposed amortization period of two years, and a decrease of $646,563 to reflect Electric Rate Case Expense of $2,586,251 to amortize over a period of four years. This reflects an increase of two years in the period over which the total will be amortized.

Mr. Latham testified that the Settlement Agreement's $12,270,000 depreciation reduction equates closely to the OUCC's recommended $12,557,795 reduction to NIPSCO's proposed depreciation. He also testified that the agreed $5,556,445 reduction to amortization expense is due to extending the amortization periods for the TDSIC and Electric Rate Case Expense regulatory asset balances from two to four years. He said extending the amortization period for these assets reduces the annual financial burden on ratepayers. NIPSCO agreed to also make a compliance filing at the conclusion of all amortization periods to remove the amortization from the revenue requirement and adjust rates accordingly. Mr. Latham explained that NIPSCO's agreement to adjust rates will lower rates as the amortization periods end.

Mr. Gorman testified that the Industrial Group proposed a significant reduction to NIPSCO's depreciation expense of $46.36 million, based, in large part, on the Industrial Group's concerns related to proposed increases in decommissioning costs for NIPSCO's steam production assets, as well as reductions in net salvage value. Mr. Gorman testified that in his view, the $10 million assigned by the Settlement to reduce decommissioning costs and adjust net salvage value is a reasonable result within the range of reasonably expected outcomes.

E. Pro Forma Net Operating Income at Present Rates. The Settlement Agreement resolved issues raised by the parties concerning pro forma net operating income at present rates for fuel costs and O&M expenses. The Settling Parties agreed that the base cost of fuel proposed in NIPSCO's case-in-chief will be reduced by $8,970,840 and agreed to a $20 million reduction to total O&M. This reduction is a compromise to resolve numerous disputed issues, including NIPSCO labor vacancies (generation and non-generation related), NCSC labor vacancies, vegetation management expense, and costs incurred to execute NIPSCO's rate case.

Mr. Latham testified that the Settling Parties agreed NIPSCO's pro forma O&M expenses should be decreased by $20 million. He said this reduction is a general compromise to resolve numerous disputed O&M issues including labor vacancies, vegetation management expenses, and rate case expenses. He explained the OUCC advocated that ratepayers should not be financially responsible for all of NIPSCO's rate case expenses and a reduction was incorporated into the Settlement O&M expense. He stated the Settling Parties also agreed to a $8,970,840 reduction in fuel costs consistent with the OUCC's litigation position.

Mr. Gorman testified that the total reduction in NIPSCO's O&M expense of $20 million resolves a number of disputes between the parties, including NIPSCO's proposed increases in vegetation management program costs, unfilled labor positions, corporate shared services costs, and challenges to the recovery of litigation related expenses. In his opinion, the total adjustment reflects a reasonable resolution to the areas of dispute and good faith efforts to reach compromise in the face of both sides' litigation risk.

F. Low Income Program. The Settlement provides for the approval of NIPSCO's proposed bill assistance program (Rider 697 – Universal Service Program Rider) with the following changes: (1) in recognition of concerns the OUCC expressed, NIPSCO agrees to modify the bill assistance program from an opt-out program as proposed in NIPSCO's rebuttal to a voluntary, opt-in program; and (2) in recognition of concerns expressed by the Settling Parties, NIPSCO will make an annual, below the line (i.e., not to be recovered through rates) shareholder contribution of $1,500,000.

Mr. Latham testified the bill assistance in the Settlement is a ratepayer favorable outcome as NIPSCO will contribute a significantly greater amount of shareholder funding to the program than NIPSCO proposed in its case-in-chief ($400,000). He also testified that ratepayers will have the opportunity to opt into the program to help those needing assistance and that a benefit of opt-in over opt-out is that an opt-in plan does not rely on involuntary ratepayer contributions, but instead enables ratepayers to choose to participate in NIPSCO's assistance program.

G. Other Customer Issues. The Settlement includes the following additional provisions to address affordability: (1) the Settling Parties agreed to a reduction of NIPSCO's

customer deposit from $50 to $0 for all gas and electric customers who receive bill assistance through the Low Income Home Energy Assistance Program ("LIHEAP"); (2) for electric customers who are disconnected for non-payment of charges, NIPSCO agreed to waive its $90 electric reconnection charge (at the meter during normal business hours) set out in Section 15.1.1 of its General Rules and Regulations no later than with the implementation of Step 2 rates; (3) NIPSCO agreed to delay disconnection for non-payment of electric service if temperatures are below 20 degrees or above 90 degrees on the day of disconnection or are forecasted to be below 20 degrees or above 90 degrees the following two days; and (4) NIPSCO committed to a stakeholder process within six months of the date of a final order in this Cause with the intent of incorporating a public-facing electric vehicle ("EV") rate to facilitate charging at customer-owned locations in NIPSCO's next electric base rate case.

Mr. Latham testified the elimination of the customer deposit will benefit NIPSCO's gas and electric LIHEAP-eligible customers by making additional funds available to meet their day-to-day expenses rather than their cash being required for this deposit. He testified that waiving NIPSCO's $90 reconnection charge no later than the implementation of Step 2 rates will enable further potential ratepayer savings. Additionally, delaying disconnection for non-payment of electric service if temperatures are below 20 degrees or above 90 degrees on the scheduled day of disconnection or are forecasted to be below 20 degrees or above 90 degrees the following two days is beneficial during periods of extreme weather for ratepayers who may struggle to pay electric bills. Regarding the stakeholder process for a public-facing EV rate, Mr. Latham stated that, as the need for EV chargers grows, NIPSCO's commitment to a stakeholder process that incorporates input from all affected parties, including the public, should facilitate the availability of this additional electric infrastructure.

Ms. Perry stated that in her direct testimony, she recommended that NIPSCO offer a rate structure for business customers who are interested in owning and operating public EV charging equipment, specifically direct current fast chargers, to ensure that such chargers owned by a third-party are able to remain competitive. She said this would foster a robust marketplace for EV charging equipment, encouraging the expansion of a comprehensive EV charging network across Petitioner's service territory. She testified the stakeholder process and intent to incorporate a public facing EV rate in NIPSCO's next rate case adopts her recommendation and Walmart commends NIPSCO for being willing to take this necessary step to further the advancement of competitive EV development to the benefit of its service territory and hopes to see similar developments throughout Indiana.

H. <u>Phased Rate Implementation</u>. The Settlement provides that the rate changes will be implemented on a services rendered basis after NIPSCO's new tariffs have been approved by the Commission's Energy Division. Implementation of the agreed rate increase would occur in multiple steps, as follows:

Step 1 rates shall be implemented on a services rendered basis as soon as possible following the issuance of an order and will be based on actual net plant certified to have been completed and placed in service no later than May 31, 2025, except for the Fairbanks and Gibson projects. The Settling Parties agree that Step 1 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of May 31, 2025. Prior to implementation of Step 1 rates, NIPSCO will certify the net original cost rate base and

current capital structure as of May 31, 2025 and calculate the Step 1 rates using those certified figures. For purposes of Step 1 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of May 31, 2025. NIPSCO will provide all parties to this proceeding with its certification. The Settling Parties, and other interested parties to this proceeding, will have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. All parties to this proceeding shall be permitted to conduct discovery to verify relevant construction costs and in service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual net plant in service as of May 31, 2025, and rates will be trued up, with carrying charges, retroactive to the date Step 1 rates were put into place.

Step 2 rates shall be implemented on a services rendered basis as soon as possible after the end of the Forward Test Year and will be based on actual net plant certified to have been completed and placed in service no later than December 31, 2025. The Settling Parties agree that Step 2 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2025. Prior to implementation of Step 2 rates, NIPSCO will certify the net original cost rate base and current capital structure as of December 31, 2025 and calculate the Step 2 rates using those certified figures. For purposes of Step 2 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2025. NIPSCO will provide all parties with its certification. The Settling Parties, and other interested parties to this proceeding, will have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. The Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 rates were put into place.

In the event Fairbanks and/or Gibson are not in service by the general rate base cutoff for Step 1 (May 31, 2025) but come into service on or before the general rate base cutoff for Step 2 (December 31, 2025), the Settling Parties agree to up to two additional steps to include these projects in rates earlier than Step 2 (end of the Forward Test Year). The compliance filing(s) for the additional step(s) will be based on the addition to rate base and associated depreciation expense for Fairbanks or Gibson (whichever the case may be) upon the filing of a certification that the plant is in service. The rates will use the capital structure used for Step 1 rates. NIPSCO shall file a certification that the asset is in service, with a copy to all parties. The rates would take effect on the same interim-subject-to-refund basis as Step 1 and Step 2 rates, with the same period for other parties to raise objections. To the extent Fairbanks and/or Gibson are not in service by May 31, 2025, but are in service by the time of the Step 1 compliance filing in this Cause, NIPSCO may include the plant in Step 1 rates calculated as provided in this paragraph.

Mr. Latham testified that, as advocated by the OUCC, the Settling Parties agreed the rate changes will be implemented on a services-rendered basis after NIPSCO's new tariff has been approved by the Commission's Energy Division. This helps to ensure the new rates are not applied to electric service rendered before their approval. Step 1 rates will be implemented on a services-

rendered basis as soon as possible following the issuance of an order in this Cause and approval of NIPSCO's new tariffs.

I. Cost of Service and Rate Design. In the Settlement, the Settling Parties acknowledge that, as presented in NIPSCO's case-in-chief and rebuttal, certain rate classes are being subsidized by several other rate classes. The Settlement Agreement proposes to mitigate a portion of the on-going subsidy concerns raised by multiple parties in an effort to balance the goal of subsidy reduction with a policy of gradualism. Consistent with the mitigation approach approved in the 45772 Order, the Settlement revenue requirement reduction (i.e., the settled annual revenue requirement below NIPSCO's as-filed case in chief) will be apportioned as follows: (1) set revenues for Rate 631 at cost of service based on 162.061 megawatts ("MW") of allocated Tier 1 demand; (2) no revenue change to Rate 642 and Rate 643; (3) credit $575,000 of the Settlement revenue requirement decrease first to each Rate 623 and Rate 626; (4) allocate 25% of the remaining Settlement revenue requirement decrease to the subsidizing classes in proportion to their excess revenues (25% portion); and (5) allocate the remaining amount on an across-the-board basis in proportion to NIPSCO's case-in-chief proposed revenues (the "25% portion"). Because Rate 631 is being brought to parity assuming 162.061 MW of allocated demand, it will not receive either a reduction relating to the 25% portion or a reduction related to the 75% portion, nor will Rate 642 and Rate 643 as there is no change in their revenues. Rate 611 will participate in the across-the-board reduction (the "75% portion"). The provisions of this paragraph are to be implemented in the cost of service and rates included with NIPSCO's testimony supporting the Settlement Agreement.

In Petitioner's Exhibit 16-S, Mr. Taylor presented the Settlement revenue apportionment, and the Settlement proposed class rate increases in Attachment 16-S-A. Table 1 in Mr. Taylor's settlement testimony shows the mitigation of interclass subsidies from the case-in-chief proposal to the Settlement. He presented Attachment 16-S-B which shows detailed calculations for each rate component of each rate schedule, as well as how the targeted total rate schedule revenue will be achieved using the proposed rates and volumes. Further, Attachment 16-S-B shows the transition of revenues at current rates and existing 500 series rate classes to the proposed revenues at the 600 series rate classes. Mr. Taylor sponsored Attachment 16-S-C, showing the typical bill impacts for residential customers. Mr. Taylor also sponsored Attachment 16-S-D as a revised version, consistent with the Settlement, of Attachment 16-H to Petitioner's Exhibit 16, providing the updated tracker allocators that result from the Settlement changes to cost of service and revenue mitigation.

The Settlement Agreement provides that, in light of issues raised by the OUCC, the Industrial Group, U.S. Steel, and the CAC, NIPSCO will study its cost of service production, transmission, and distribution classification and allocation ("Allocation Study") before filing its next general electric rate case. This will include the study of the classification and allocation of production, transmission, and distribution customer, demand, and energy related costs both in base rates as well as in the fuel adjustment clause ("FAC") and resource adequacy ("RA") trackers. In its next general rate case, NIPSCO will file testimony addressing the results of the Allocation Study and supporting its decision regarding whether to make changes to the classification and allocation of production, transmission, and distribution costs.

The 45772 Settlement contemplated future reductions in Rate 531 Tier 1 contract demand and called for progressively narrowing the disparity between the Rate 531 allocated Tier 1 demand and the actual Tier 1 contract demands of customers in that class to bring that rate to parity with the cost to serve. The Settling Parties in this Cause agreed that the provisions of the 831/531 Modification Settlement and Section B.7.(e) through (g) of the 45772 Settlement continue to apply. The Settling Parties further agreed that the method for future reduction in Rate 631 Tier 1 allocated and contract demand provided for in the 831/531 Modification Settlement will be accomplished through the approach recommended by Mr. Dauphinais, with the exclusion of costs associated with Sugar Creek Generating Station, as recommended by Ms. Schuepbach. Using this approach, and reflecting the revenue adjustments under the Settlement, the allocated Rate 631 Tier 1 demand shall be 162.061 MW.

The Settling Parties agreed to Mr. Dauphinais's recommendation of proportional reductions to Rate 631 Tier 1 contract demand to progressively narrow the disparity between Rate 631 allocated demand and class contract demand to move the rate toward the actual cost of service. The minimum contract demand assumed for purposes of the Settlement is 153.692 MW. The Rate 631 charges (transmission, energy, and demand) will be based upon the 153.692 MW of assumed contract demand, which is expected to be consistent with executed Rate 631 contracts. The Settling Parties agree that further reductions to Rate 631 Tier 1 cost allocations in future rate proceedings should continue to follow the methodology set forth in Paragraph 7(f) of the 45772 Settlement employing the computational methodology utilized in the Settlement.

The Settlement also addresses a number of rate design issues unrelated to Rate 631. The Settlement provides that the revenue requirement decrease allocated to Rate 626 will be applied 50% to Rate 626's demand charge and 50% to its energy charge. The Settlement adopts the customer charges proposed by NIPSCO, except NIPSCO's existing monthly charge of $14 shall remain for Rate 611.

Mr. Taylor testified the Settlement allocated cost of service study ("ACOSS") structure and methodologies remain consistent with those described in his direct and rebuttal testimonies. The changes to the revenue requirement related to legacy coal generation were reflected in an update to the Rate 631 allocated demand in the Settlement ACOSS and the resulting Rate 631 cost of service is the basis of the revenue increase for that customer class. The Settlement ACOSS was further used to inform revenue apportionment to NIPSCO's other remaining customer classes. Mr. Taylor testified that while the ACOSS supports a higher residential customer charge, the Settling Parties agreed that the customer charge for Rate 611 will remain at $14 per month.

Mr. Latham testified the Settling Parties spent considerable time negotiating the revenue allocation among NIPSCO's rate classes. He said that because the OUCC represents all customer classes, the OUCC works to help ensure cost increases are fairly distributed across rate classes, while also being mindful of the importance of applying the principle of gradualism. The Settling Parties agreed to the customer charge increases NIPSCO proposed in its case-in-chief, with one exception. As recommended in the OUCC's direct testimony, NIPSCO's monthly customer charge for residential customers (Rate 611) will remain at $14. He said maintaining this charge is beneficial because ratepayer actions to mitigate the volumetric component of their bills may have a greater effect on the overall bill when the fixed charge is lower than the amount NIPSCO proposed in its case-in-chief.

Ms. Schuepbach testified the revenue requirement by customer class is based on the use of a four coincident peak ("4CP") allocation factor for production demand costs. Although her recommendation for the allocation of transmission costs by voltage was not addressed in this case, NIPSCO agreed to conduct an Allocation Study before filing its next general electric rate case. She said NIPSCO will either propose new methods for the classification and allocation or file testimony with the results of its analysis demonstrating why its current approach is still appropriate. She expects the Allocation Study to subfunctionalize transmission costs by voltage and then allocate the costs to each customer class based on the voltage at which they receive service for all rate base and revenue requirement components. She also expects NIPSCO to provide the results of the subfunctionalization analysis, describe how it affects the cost allocation to each rate class and for NIPSCO's Riders. She expects the allocation of transmission costs to Rate 631 to decrease as the majority of Rate 631 customers do not take power at, or use, the 69 kilovolt system.

Ms. Schuepbach testified the Rate 631 Tier 1 load and cost allocation in the Settlement Agreement is easy to understand, easy to duplicate, and defendable based on the language in the 45772 Settlement. She stated that when NIPSCO files its next general rate case, she expects to see the Rate 631 Tier 1 load and cost allocation calculation include only legacy coal assets, no trackable fuel, and be based on actual data for the coal plants. She expects that, as the coal legacy revenue requirement decreases, so will the allocated demand costs to Rate 631, and Rate 631 will reach 70 MW by 2035 when the coal legacy assets are fully depreciated and amortized.

Ms. Schuepbach testified the Settling Parties agreed to mitigate a portion of the settled revenue requirement increase to be consistent with a policy of gradualism. She said this mitigation is consistent with the 45772 Settlement, in that the differential continues to narrow between actual class capacity subscriptions and the allocated class capacity level. Rate 631 is held at parity based on a set total class demand level, as it was in the prior rate cases. She explained that absent Rate 631, there were and are valid concerns that industrial customers could shift their production to locations outside of NIPSCO and Indiana. She said that the Settlement revenue requirement allocated to each customer class was a product of negotiations that represented a reasonable compromise among the Settling Parties, considering very different views on the proper cost of service allocation methodologies. She opined that, in recognition that one allocation method compared to another dramatically shifted costs among rate classes, the Settlement Agreement represents a reasonable balance among the different perspectives that yields results that do not unduly harm one rate class over another and does not endorse one allocation method over another. She stated that with respect to U.S. Steel, the resulting rate increases to Class 631 of 10.32% represent an improvement compared to NIPSCO's original revenue proposal.

Ms. Schuepbach stated that for settlement purposes, the overall class rate increases are reasonable. The demand charge is significantly higher than most utility demand charges, but this is partially due to the difference between the demand costs allocated to Rate 631 and the actual contracted demand for the Rate 631 customers. She said if the demand costs of $65,921,733 are allocated to Rate 631 based on 162.1 MW of demand, the average rate is $33.90 per kW. However, the actual contract or billing demand for the class is 153.7 MW, resulting in a rate of $35.74 per kW, which is 5.4% higher. She said this disconnect between the allocated demand and the contract demand puts additional upward pressure on the demand charge.

Ms. Perry stated Walmart initially recommended that any reduction in revenue requirement from NIPSCO's originally requested amount be allocated by applying 50% of the overall revenue reduction to those rate classes who are paying in excess to their cost-based levels, except that in no event should a subsidizing rate class be moved to a subsidized position. The remaining 50% of the overall revenue reduction should be evenly applied to mitigate the proposed increases for all rate classes on an equal percentage basis. She testified that, while not adopting her proposal specifically, the revenue allocation set forth in the Settlement Agreement essentially adopts her proposal in concept. She stated that providing for a subsidy reduction by using 25% of the overall reduction in annual revenue (as opposed to Walmart's recommended 50%), combined with the additional marginal credit to Rate 626, is a reasonable compromise that benefits all classes while moving no class from a subsidized position to a subsidizing position or vice versa. However, she stated Walmart continues to maintain that greater movement to rectify subsidies is necessary.

Ms. Perry noted Walmart's initial concern that the structure of Rate 626 did not reflect appropriate intra-class cost causation by recovering demand-related costs through the energy component of the rate. Thus, she recommended that if a lower revenue requirement than that proposed by NIPSCO was approved, then the reduction to Rate 626's revenue requirement should be used to reduce the energy charge until the allocations match NIPSCO's cost of service study. She testified the Settlement Agreement adopts a compromise position that results in reasonable movement towards a cost-based rate design structure for Rate 626 that is also revenue neutral to all other rate classes.

Mr. Dauphinais stated the cost of service study presented in this case by NIPSCO was supported by expert testimony and was further supported by several parties including the Industrial Group. He noted its consistency with the cost of service methodology previously approved by the Commission and said the subsidy reduction provision is essentially identical to the corresponding provision in the 45772 Settlement. Several parties, including the Industrial Group, proposed greater reductions to inter-class subsidies, and other parties proposed less. Mr. Dauphinais testified the Settlement strikes a reasonable balance between the respective positions taken by the parties. The Settlement calls for NIPSCO to conduct an Allocation Study and to report on that study in its next rate case filing. He said it is always appropriate for a utility to review and assess reasonable approaches to analyzing cost of service in light of current circumstances and this provision properly leaves the decision to NIPSCO as to whether or not to propose any changes in its next rate case.

Mr. Dauphinais testified that under the 45772 Settlement, which includes the Rate 831/531 Modification Settlement, there will be progressive reductions to both the differential between imputed class demand used for allocation purposes and actual contract demand, as well as contracted Tier 1 demand in excess of the tariff minimum under Rate 631 and successor rates. In both respects, the reductions are calibrated to decreases in costs related to legacy coal plants as recovered in base rates. While this mechanism was approved by the Commission in NIPSCO's last rate case, he said there were some differences among the parties regarding the appropriate way to implement the mechanism. In the Settlement Agreement, the parties agreed to adopt the methodology proposed in his direct testimony, as well as a recommendation proposed in Ms. Schuepbach's testimony. He said the agreed methodology provides clarity regarding the implementation of the Rate 631 Tier 1 adjustment mechanism approved in the 45772 Order, is

consistent with the terms of that previously approved agreement, and provides appropriate guidance and framework for future implementation in successive rate proceedings.

J. Multi-Family Rate. In the Settlement, the Settling Parties agree NIPSCO's proposed multi-family rate, Rate 615, shall not be implemented. NIPSCO will collect additional data on residential customer housing types to better identify multi-family customers and further analyze cost differentials between single- and multi-family residential customers and may consider requesting a new multi-family rate for qualifying residential customers in its next rate case. Once additional analysis is complete, NIPSCO will meet with the CAC, the OUCC, and any other interested stakeholders prior to filing its next base rate case to discuss a potential multi-family rate and will provide interested stakeholders with the results of its analysis.

Mr. Taylor testified that both the OUCC and the CAC addressed proposed Rate 615, expressing concerns about the robustness of Petitioner's analysis that was used to establish the rate. Both parties were critical about NIPSCO's ability to identify the potential multi-family customers, the associated load research information used to quantify those customers' demand requirements, and the planning and engineering information used to determine the cost of service differences between single family and multi-family premises. Ultimately, the CAC recommended the adoption of Rate 615 whereas the OUCC recommended denial pending more thorough study. In recognition of these concerns, the Settling Parties agreed to forgo the separation of multi-family customers from Rate 611 at this time.

Mr. Latham testified NIPSCO will continue to collect data on residential customer housing types to better identify its multi-family customers and analyze the cost differentials between NIPSCO's single- and multi-family residential customers. He said this additional insight into NIPSCO's customer housing types and a more robust sample than NIPSCO used in this proceeding should facilitate a better informed analysis when considering a separate multi-family rate and its prospective impact upon NIPSCO's rate classes.

K. Data Center Sub-docket. Certain parties requested the creation of a sub-docket for purposes of developing a standard tariff offering and addressing other pertinent issues related to new large load customers that may locate in NIPSCO's electric service territory. The Settlement recognizes that since the filing of NIPSCO's case-in-chief and the OUCC's and intervenors' cases-in-chief, a filing was made related to NIPSCO's proposed overall strategy to serve large load customers, in which it was acknowledged that NIPSCO has not entered into any special contract or equivalent agreement for energy services for a large load customer. NIPSCO expressed its intention that any large load customer that may enter into a contract for electric service will commit to pay the direct, incremental costs associated with serving their load and some portion of the costs of NIPSCO's existing electric system. Accordingly, NIPSCO agreed that to the extent it enters into such contract(s), NIPSCO commits to timely file a proposal with the Commission to pass back to NIPSCO's current electric customers the revenues collected that are related to payment for recovery of some portion of the costs of NIPSCO's existing electric system paid by the large load customer(s). Under the Settlement, no party waives or is otherwise limited in making any argument in pending Cause No. 46183 or related dockets surrounding large load customers, but NIPSCO is precluded from requesting that any portion of the above identified revenues not be passed to NIPSCO's then current electric customers.

Mr. Latham stated that NIPSCO intends for any large load customer that may enter into a contract for electric service to commit to pay the direct, incremental costs associated with serving its load and some portion of NIPSCO's existing electric system costs. To the extent NIPSCO enters into such contracts, he stated NIPSCO committed to timely filing a proposal to pass back to its current electric customers the revenues collected related to payments for recovery of the portion of the costs of NIPSCO's existing electric system paid by large load customers. He explained it is beneficial to NIPSCO's pre-existing ratepayers if large load customers fund a portion of system costs because this funding would reduce system costs for NIPSCO's other ratepayers and be realized when NIPSCO receives an order on its "pass-back" filing.

Ms. Schuepbach testified that, although NIPSCO has stated existing customers will not be harmed or saddled with any incremental costs associated with large load customers, she hopes her concerns regarding the transparency of the transactions between NIPSCO and the large load customers and unintended effects on existing rate payers will be addressed in Cause No. 46183.

L. Other Relief Requested by NIPSCO. Section B.14. of the Settlement Agreement provides that any matters not addressed by the Settlement Agreement but expressly supported by NIPSCO's testimony should be approved as NIPSCO proposed or, if modified in NIPSCO's rebuttal, consistent with such modification, without waiving the right to challenge such resolution prospectively.

M. Typical Bill Comparison. Attachment 2-S-A of Petitioner's Exhibit 2-S shows the estimated impact on an average residential customer's monthly electric bill and how that compares to the estimated bill impact on customers in NIPSCO's case-in-chief. Ms. Whitehead said that NIPSCO estimates that residential bills for the average customer consuming 672 kWh would increase approximately 16.75% following Step 2 rate implementation, inclusive of anticipated changes in trackers. In NIPSCO's case-in-chief, residential customers would have received a 22.01% increase following Step 2 rate implementation based on average residential customer usage of 729 kWh. She explained that combining the multi-family rate (Rate 615) into Rate 611 results in lower average overall residential customer consumption, making the comparison of these average residential bill impacts challenging.

Mr. Taylor presented the typical bill impacts for residential customers on Attachment 16-S-C of Petitioner's Exhibit 16-S.

N. Addenda to the Settlement Agreement. Ms. Whitehead explained that Addendum A contains separate terms between NIPSCO and LaPorte County, which were reached to address concerns raised by LaPorte County and that allowed it to not oppose the Settlement. Addendum B contains separate terms between NIPSCO and the RV Group, which were reached to address concerns it raised and that allowed the RV Group to sign the Settlement. She said neither of the addenda have a direct base rate impact, but do, in part, respond to and address concerns raised by both parties. Because there is no direct base rate impact, NIPSCO does not believe the Commission needs to take any action on the addenda. However, they were included to ensure the Commission was aware of these terms, to memorialize NIPSCO's commitments to these parties, and to provide the basis for the positions to either not oppose or to sign on to the Settlement

O. Public Interest. Ms. Whitehead testified that the Settlement is consistent with the public interest. She stated the regulatory compact is, by necessity, a balancing of interests between the utility and its stakeholders. As a general matter, negotiated resolutions to complex issues are consistent with the public interest because the result is the byproduct of input and compromise by the various parties that are directly impacted by the outcome. Ms. Whitehead testified that with respect to the issues addressed in this Cause, NIPSCO was able to reach an agreement that provides for rates and charges sufficient to allow for the recovery of the cost of providing service to its customers, as well as a return of and on its investments in plant and equipment needed to serve its customers. She said the issues addressed in the Settlement and supporting testimony demonstrate the value of compromise in the context of the public interest.

Mr. Latham testified the Settling Parties each made concessions involving considerable give and take on multiple contested issues to reach an overall agreement, reducing the risk and expense of litigation. He testified that the Settlement Agreement, considered in its entirety, serves the public interest by guaranteeing ratepayer savings of $111,616,865 annually, if approved, compared to NIPSCO's case as initially filed. The OUCC considers the Settlement Agreement to be both reasonable and in the public interest, given the facts and applicable law.

8. Opposition to Settlement Agreement. Mr. Inskeep testified as to the CAC's opposition to the Settlement. Specifically, he contends that the Settlement: (1) provides for a modest 30.3% reduction to NIPSCO's overall revenue increase but residential customers will see a much smaller 23.6% reduction; (2) is premised on the acceptance of NIPSCO's ACOSS featuring a 4CP cost allocation that unfairly assigns large portions of production costs to residential customers, even though the Commission recently determined in a different utility's rate case that the 12 coincident peak ("12CP") cost allocation method was superior, and the resulting rates are unjust and unreasonable; (3) contains a term related to NIPSCO conducting an Allocation Study as part of its next rate case that is wholly inadequate; (4) misallocates renewable energy and battery energy storage tax credits, which redistributes millions of dollars each year in tax credits paid for by residential customers, to non-residential customers; (5) provides for an unfairly large portion of the reduction in revenue requirement to go towards reducing the rates of non-residential customers, leaving little benefit and extraordinary rate increases for the residential class; (6) fails to include NIPSCO's proposed multi-family rate, instead lumping this distinct rate class in with Rate 511, leading to rates that far exceed the cost of service for multi-family customers based on NIPSCO's ACOSS; (7) transmogrifies what had been a well-designed low income program into one that mirrors recently failed programs of other Indiana electric utilities, with substantially fewer benefits for eligible customers and without a long-term sustainable funding mechanism; and (8) does not provide adequate ratepayer protections with respect to significant data center load growth being actively negotiated by NIPSCO today.

Mr. Inskeep argued the Settlement is not in the public interest because it is inconsistent with Indiana's affordability pillar and would result in residential rate shock inconsistent with the principles of gradualism and make multi-family residential customers worse off than what NIPSCO presented in its case-in-chief. He said the terms impose a preference for non-residential rate classes over residential customers, resulting in unjust and unreasonable rates. Mr. Inskeep testified that critical residential affordability protections initially proposed by NIPSCO were removed or significantly weakened. He recommended the Commission reject the Settlement or substantially modify its terms.

9. Settlement Rebuttal. Several of the Settling Parties filed settlement rebuttal testimony. The RV Group and Walmart submitted a joinder in specific statements and positions taken by Mr. Taylor and Mr. Dauphinais.

Ms. Whitehead testified that her direct and rebuttal testimony detailed NIPSCO's proposals intended to address customer affordability. She testified the Settlement further reduces NIPSCO's as-filed revenue requirement by over $110 million and contains several provisions designed to address the needs of NIPSCO's lower income electric customers. She stated the agreed revenue reduction is significant and the revenue allocation is fair and reasonable. She stated that while the CAC opposes the Settlement, it contains a number of items that align with the CAC's preferred positions, including no increase in the residential customer charge, a reduction to NIPSCO's ROE, eliminating the security deposit for LIHEAP-qualified customers, and timely phase out of the electric reconnection charge for non-payment. She noted the Settlement is either supported or not opposed by nearly every party and was diligently negotiated in an effort to reach a reasonable outcome that benefits all rate classes. She testified that ultimately, within the constraints available in a highly complex rate case, the Settlement addresses customer affordability for all rate classes through creative problem solving and meaningful adjustments and should be approved in its entirety without modification.

Responding to Mr. Inskeep's contention that the Settlement's overall revenue reduction is modest and inconsistent with the affordability pillar, Ms. Whitehead testified there was a significant focus on affordability by all parties involved in this case. She identified the steps that NIPSCO took to mitigate the bill impact of its initially requested rate relief, which was driven by nearly $2 billion in pre-approved investments in renewable generation assets. She noted that no party, including the CAC, opposed recovery of NIPSCO's generation assets expected to be in service by December 31, 2025. Ms. Whitehead stated NIPSCO's pre-filing mitigation steps included: eliminating paysite convenience fees for customers paying their bill by cash or check; implementing a unique ratemaking construct to reduce NIPSCO's total rate request to: (1) reflect retirement of Schahfer Units 17 and 18 that will occur on December 31, 2025 (i.e., beyond the Forward Test Year) and (2) reduce base cost of fuel related to the Investment Tax Credit ("ITC") and Production Tax Credit ("PTC"); (3) proposing a rate phase-in approach for the Gibson and Fairbanks projects that reduces the cost to customers; (4) proposing depreciation accrual rates that do not reflect the most current estimates for cost of removal associated with the Bailly Generating Station and instead utilizing the estimates supporting current, and lower, depreciation rates; and (5) requesting a lower than recommended ROE.

Regarding the CAC's assertion that NIPSCO's residential customers will experience rate shock, Ms. Whitehead testified that Mr. Inskeep's residential bill presentation is inaccurate. She said the figure only projects NIPSCO's rates through 2026 and does not reflect the Commission's approval of recent rate increases to residential bills for CEI South and Duke of approximately 8.08% and 13.11%, respectively. She testified the Settlement furthers affordability because the Settling Parties agreed to nearly $112 million of reductions to NIPSCO's proposed revenue requirement, primarily relating to NIPSCO's proposed ROE, O&M expense, and depreciation and amortization expense. Ms. Whitehead testified that as a result of the Settlement, NIPSCO estimates that the residential bill increase for an average NIPSCO customer has been reduced from 22.01% to 16.75%, which is broken into multiple steps over several months. She said, by comparison, the agreed revenue requirement reduction in this Cause exceeds that approved in CEI South's electric

rate case (Cause No. 45990) while also incorporating customer affordability measures and reasonably balances the remaining pillars of reliability, resiliency, stability, and environmental sustainability. She acknowledged that a rate increase of any amount can impact customers, particularly those with limited or fixed incomes, but stated the Settlement contains specific measures designed to target assistance to those customers who need it the most.

Ms. Whitehead testified that in addition to the reduction to NIPSCO's proposed revenue requirement, other non-revenue requirement terms in the Settlement that benefit residential customers include: (1) eliminating the $50 customer deposit for NIPSCO's gas and electric customers who receive bill assistance through LIHEAP; (2) no later than the implementation of Step 2 rates, waiver of NIPSCO's $90 electric reconnection charge for electric customers who are disconnected for non-payment of charges; (3) delay of disconnection of electric service if temperatures are below 20 degrees or above 90 degrees on the scheduled day of disconnection or if forecasted the following two days; and (4) no increase to the monthly residential customer charge of $14. The Settlement also reflects creation of a bill assistance program for NIPSCO's low income electric customers funded by an annual $1.5 million contribution from NIPSCO shareholders and voluntary customer contributions.

In response to Mr. Inskeep's criticism of the bill assistance program provided for in the Settlement, Ms. Whitehead testified that the parties' testimony in this Cause reflects disagreement on the appropriate design of a bill assistance program for low income customers, primarily as to whether a non-bypassable, opt-in, or opt-out program design was appropriate. She said NIPSCO agreed to modify its proposed program to achieve a global settlement in this case with all Settling Parties. She also noted that the Commission has not approved an electric low income program structured like NIPSCO's proposed program, and in Cause No. 45465, the Commission rejected NIPSCO's low income program for electric customers due to its opt-out nature. She testified that while NIPSCO appreciates the CAC's continued support of meaningful bill assistance programs to low income customers, denying or modifying the Settlement based on the program's modified design would serve only to harm the eligible low income customers who stand to benefit from the bill assistance that will now be available. She noted that NIPSCO's shareholder contribution is considerable and Petitioner is committed to targeting all bill assistance funding to customers most in need.

As for the elimination of the multi-family rate proposed in NIPSCO's direct case, Ms. Whitehead testified that the parties could not agree on the strength of NIPSCO's supportive data or how many multi-family customers there are in NIPSCO's territory. She noted that although the CAC recommended approval of NIPSCO's multi-family rate, Mr. Inskeep advocated additional data be provided in NIPSCO's next rate case related to metering and transformer costs. She testified that ultimately, the Settlement addresses the concerns raised by the OUCC, a key stakeholder in terms of representing the interests of residential ratepayers, regarding the level of analysis NIPSCO had undertaken to support its multi-family rate.

Responding to Mr. Inskeep's concern that the Settlement does not provide adequate ratepayer protection with respect to significant data center load growth, Ms. Whitehead testified the Settlement describes NIPSCO's intention as it relates to how large load customers that enter into a contract for electric service will commit to pay the direct, incremental costs associated with serving their load and some portion of the costs of NIPSCO's existing electric system. She

disagreed that such treatment is discriminatory or warrants additional scrutiny and consideration. She said NIPSCO has not entered into any contract for electric service with any large load customer and the Forward Test Year in this case does not include any anticipated load growth associated with any such customer. She indicated Mr. Inskeep's present concerns – which are hypothetical and premature – are best addressed within the context of a regulatory filing related to the approval of any such special contract. She also noted that one of the parties who proposed creating a data center subdocket in this Cause, U.S. Steel, signed on to the Settlement and supports its intended outcome.

Mr. Taylor replied to Mr. Inskeep's testimony on cost allocation and rate design. He disagreed with the CAC's assertion that a 4CP cost allocation for production costs is not reasonable in light of MISO's resource adequacy requirements. He testified that NIPSCO has always had the obligation to provide safe and reliable electric service to its customers in all hours of the year and this obligation existed before MISO was created. He said this obligation does not mean that all hours of the year contribute equally (or at all) to the investments necessary to provide reliable service. Rather, the investments driven by a very small number of hours, which have traditionally been in the summer, have caused the investment in the generation system that is able to provide reliable service in all hours of the year. Mr. Taylor stated this reality has not changed with the seasonal resource adequacy construct, meaning that the investments NIPSCO has made to meet its summer needs allow it to also meet its other seasonal requirements. Mr. Taylor testified that, while NIPSCO's 2024 IRP shows it may need to invest in additional resources to meet the winter season requirements in 2028, this depends on a number of factors and NIPSCO has not proposed any such investments to the Commission. He said Mr. Inskeep's testimony conflates compliance within the IRP models with what seasons are actually binding and driving investment; it is the latter that is relevant.

Mr. Taylor also testified that the CAC's initial position was to abandon the 4CP allocator in favor of the Probability of Dispatch method, or an alternative position of a Peak and Average allocation method. He explained that his rebuttal testimony critiqued the CAC's positions, which the Commission has rejected many times. He also noted that the CAC did not attempt to refute his rebuttal position related to these allocators but instead made a catch-all recommendation to use 12CP, which was provided with no analysis and only one sentence for support.

In response to Mr. Inskeep's continued disagreement with the allocation of PTCs and ITCs using class energy as the basis for allocations and flowing the tax credits back to customers through the FAC, Mr. Taylor testified that all four of the solar and solar plus storage projects NIPSCO seeks to include in its Step 2 rate base were pre-approved by the Commission with authority to pass back PTC and ITC proceeds through NIPSCO's FAC. He explained that no party, including the CAC, opposed this pass back mechanism in those proceedings and the manner in which costs are allocated and recovered through the FAC has not changed since the Commission's approval.

Mr. Taylor explained that PTCs are not generated just because the plant exists; the energy must be produced for a PTC to be created, and the PTCs are nominated in units of dollar per unit of energy produced. He testified that both renewable and fossil-fuel units are subject to variation in output due to a number of factors, including weather, curtailments, and a host of other external influences that can impact production. Mr. Taylor explained that under the CAC's approach, one could argue that fuel expense for a coal or gas resource should be allocated using a production-

demand allocator because the fuel could not be combusted to produce energy without the existence of the plant itself. On the other hand, the plant capacity which serves as the basis for participation within the resource adequacy framework is available without producing energy.

Mr. Taylor testified that, of the total expected tax credits included in the Forward Test Year, roughly 93% are PTCs and the remaining 7% are ITCs. He explained that ITCs differ from PTCs in that the tax credits are not a function of production but rather a function of the existence of the plant (and meeting the eligibility requirements) but noted that the Commission has already directed NIPSCO to return the ITCs through the FAC, which is based on energy. Mr. Taylor explained that changing the ITC allocation to the production-demand allocator would result in a reduction to the residential revenue target of approximately $350,000 before FAC impacts, but this would not result in realized lower rates for residential customers as they are already receiving a significant subsidy from other customers. He also indicated that billing system adjustments would be needed to code a demand allocation into NIPSCO's FAC, an undertaking that is neither quick nor cost-free. Additionally, Mr. Taylor explained that Mr. Inskeep's recommendation to adjust the PTC/ITC allocation as a single item creates a process concern because a holistic review of cost allocation is needed to ensure equity across all customer groups. He said a holistic review is necessary to ensure there are no unintended consequences, that all sides are considered, and interactions between different changes are fully vetted and understood.

Regarding the CAC's concerns with the steps taken in the Settlement to apportion the agreed reduction in NIPSCO's revenue requirement to the customer classes, Mr. Taylor said the steps taken are nearly identical to those taken in the 45772 Settlement – including setting the revenue increase for the residential class at slightly above system average. He explained that the 45772 Settlement also included a term regarding the step down of Rate 531 allocated demand and the present Settlement merely implements that approved term. Mr. Taylor also noted that, while Mr. Inskeep expressed concern about the impact of NIPSCO's rate request on schools, he did not acknowledge that schools fall within the "non-residential" rate classes and stand to benefit from the needed mitigation steps included in the Settlement.

Mr. Taylor responded to the CAC's criticism that the residential rate class will experience only a 23.6% revenue requirement reduction when the overall Settlement revenue is reduced by 30.3%. Mr. Taylor stated that a system average increase not only prohibits any movement towards class parity with cost of service, but exacerbates the cross subsidy to the residential class. He said that his Table 1 shows that even under a 12CP production allocation, residential customers would still receive a subsidy of over $99 million, negating the CAC's opposition to the residential class revenue increase under the Settlement. He said that, even in a litigated outcome where the CAC's preferred outcome of 12CP is approved, it is likely a residential class revenue increase would be at or above the Settlement amount.

In response to the CAC's concerns about the absence of a multi-family rate, Mr. Taylor testified that not implementing such a rate at this time was part of the negotiation process in response to both the CAC's and the OUCC's concerns with the scope of data to support NIPSCO's proposal. He noted that Mr. Inskeep was initially critical of NIPSCO's analysis regarding the evaluation of metering and transformer costs, resulting in the CAC's recommendation for a more comprehensive evaluation in NIPSCO's next rate case. Mr. Taylor stated that the Settling Parties ultimately agreed NIPSCO would not create the multi-family rate at this time, but to conduct

further study. Mr. Taylor further testified that although the proposed multi-family rate was an effort to reduce intra-class subsidies, under the Settlement, residential customers continue to be treated equally and as a homogenous rate class.

Mr. Deupree disagreed with the CAC's position that the Settlement provides inadequate benefits to residential ratepayers. He testified that as originally proposed, NIPSCO's overall revenue increase was $368.7 million, or a 20.1% increase in Petitioner's total revenues. Under the Settlement Agreement, this proposed overall revenue increase is reduced by $111.6 million to $257.0 million. He explained that all major rate classes benefit from the reduction in NIPSCO's proposed rate increase, including residential customers. Under NIPSCO's case-in-chief, residential ratepayers would have received a $134.1 million rate increase ($124.5 million increase for single-family Rate 511 and $9.6 million for multi-family Rate 515). Under the Settlement Agreement, this revenue increase is reduced to $103.4 million, a savings for residential ratepayers of approximately $30.7 million.

Mr. Deupree testified that the Settlement reasonably resolves the differences among the parties on the ACOSS. He stated the Settlement Agreement attempts to balance some parties' desire to reduce residential subsidies under NIPSCO's current rates with concerns over the accuracy of Petitioner's ACOSS due to the allocation of costs associated with production plant.

As for the CAC's concerns regarding the allocation of benefits associated with tax credits, Mr. Deupree explained that NIPSCO's proposed pass back of tax credit proceeds to customers through the FAC, which utilizes an energy allocator, is consistent with the Commission's CPCN orders. He stated that while there are arguments for the allocation of ITC benefits on the basis of underlying production plant, he does not agree with the proposal to allocate PTC benefits on the basis of production plant in the future. Mr. Deupree testified that PTCs accrue with renewable generation, so NIPSCO will earn more PTC benefits in years when its solar and wind generators produce more power than in years in which less renewable energy is generated; therefore, Mr. Deupree concluded that PTC benefits are directly associated with total customer energy requirements and not peak demand requirements. He testified that the Settlement Agreement recognizes NIPSCO will comprehensively review cost allocations before its next base rate case, including allocation of energy-related costs in base rates and the FAC and RA trackers.

Mr. Deupree stated that his direct testimony explained the OUCC's concern that NIPSCO's multi-family rate proposal was supported by very limited analysis and research that may not be representative of actual residential customers in Petitioner's service territory. Specifically, Mr. Deupree testified that NIPSCO's proposal was supported by a load research sampling of only 127 residential customers out of a residential customer base of 431,840 (only 0.03%). Likewise, only 21 of these load research customers were found to be multi-family customers, while NIPSCO estimated there were approximately 68,195 multi-family customers on its system. He testified that although Mr. Inskeep's testimony opposing the Settlement describes Petitioner's analysis as robust, his direct testimony raised concerns similar to those of the OUCC. Mr. Deupree stated he disagrees that not implementing the multi-family rate disproportionately harms lower-income households. He said it has not been demonstrated that all, or even most, prospective multi-family customers are low income customers. Mr. Deupree testified that the agreement not to implement the multi-family rate reflects the OUCC's concern that establishment of a separate multi-family rate in the current proceeding would have likely resulted in single-family customers paying higher

rates, harming these low income customers. Mr. Deupree explained that under the Settlement, NIPSCO will continue to collect data on residential customer housing types to better identify its multi-family customers and the differences in the costs to serve these customers compared to single-family customers and provide the results of this additional study to the CAC and the OUCC. He stated that this study should provide greater insight for facilitating a more robust proposal in future proceedings.

Mr. Deupree testified that the Settlement Agreement modifies NIPSCO's proposed bill assistance program from an opt-out program to a voluntary, opt-in program. He stated that NIPSCO also agreed to make an annual, non-recoverable, $1.5 million contribution from its shareholders, as compared to its initial proposed $400,000 shareholder contribution. Mr. Deupree stated this reduces the potential impact of the proposed program on ratepayers, including low income customers, while still enabling assistance from customers who choose to participate in Petitioner's assistance program. He noted that involuntary assistance programs similar to what NIPSCO originally proposed have been rejected by the Commission in multiple prior proceedings. Mr. Deupree stated the increase in Petitioner's financial contribution and the change to a voluntary assistance program under the Settlement Agreement mitigate the Commission's previous concerns.

Mr. Deupree testified that the Settlement Agreement includes NIPSCO's stated intent that new data center customers pay for all direct incremental costs associated with serving these customers. The Settlement Agreement also conveys the intent that new data center customers will pay a portion of existing system costs, thus reducing existing customers' rates. He explained that the CAC appears to be concerned that the Settlement Agreement language is broad and fails to expressly define what is included in "direct, incremental costs" or what is meant by "some portion" of existing system costs. Disagreeing with those concerns, Mr. Deupree said the Settlement Agreement preserves flexibility in considering individual proposals from potential data center customers while recognizing NIPSCO's commitment to ensure that the addition of these new customers does not result in higher costs for NIPSCO's existing customers. It also recognizes NIPSCO's commitment to potentially reduce rates to existing customers by allocating certain existing system costs to new data center customers.

Mr. Dauphinais responded to the CAC's suggestion that the Commission should reject the Settlement because it uses a 4CP method for production costs in the underlying cost of service study instead of a 12CP allocation. Mr. Dauphinais stated this provision in the Settlement is consistent with the cost of service methodology approved by the Commission in prior NIPSCO electric rate cases, including Cause No. 45159 in which the Commission rejected the CAC's arguments. Mr. Dauphinais reiterated that the seasonal requirements do not alter the fact that the NIPSCO system retains a clear summer-peaking status that drives its capacity needs, and that the production assets acquired by NIPSCO to meet its summer (June through September) peak demand continues to inherently provide sufficient capacity to meet its MISO requirements for the rest of the year. He pointed out that Mr. Inskeep's opposition testimony does not rebut that analysis.

Mr. Dauphinais stated that the Commission's approval in Cause No. 46038 of Duke's proposal to use a 12CP allocation of production costs does not indicate that the Settlement's agreement to use a 4CP method is unreasonable. He explained that the Duke case involved

significantly different circumstances and noted that although the Commission had approved a 4CP study in Duke's prior rate case, the Duke system had been allocated on a 12CP basis for many years prior to that. By contrast, Mr. Dauphinais highlighted that, in this case, NIPSCO proposed a 4CP allocation for production costs, consistent with its established cost of service studies as approved over a number of past rate cases.

Mr. Dauphinais testified that the situation here parallels CEI South's electric rate case, Cause No. 45990, wherein CEI South sponsored a cost of service study utilizing a 4CP allocation for production assets, consistent with its longstanding methodology approved by the Commission in past cases. He said the Commission approved a settlement among less than all the parties which adopted the 4CP allocation for production costs. He noted that, in that case, the CAC opposed that settlement and argued that the 4CP methodology was unreasonable. Mr. Dauphinais stated the Commission approved the settlement in the CEI South case the week following the order in Duke's rate case, which shows the Commission did not regard the adoption of Duke's proposed cost of service study to be a barrier to approval of the cost of service terms in the CEI South settlement.

Mr. Dauphinais testified that the CAC attempted to distinguish the CEI South case on the premise that there the Commission only rejected proposals for energy-based allocation methods, whereas in this case the CAC proposed a 12CP allocation for production costs. But, in both cases, the CAC's litigation position advocated an energy-based methodology, particularly the Probability of Dispatch method. He explained that in the CEI South case, the Commission not only rejected energy-based methods, but specifically found that CEI South's system does not pass the three FERC tests which provide guidance as to whether the 12CP method would be appropriate. He said the same status supports the cost of service terms of the Settlement in this case.

Mr. Dauphinais stated that the Settlement here, like that approved in the CEI South case, provides for a substantial reduction in the revenue increase sought by the utility, to the benefit of all customer classes, while providing for continued use of the utility's established cost of service methodology. In addition, he noted the Settlement in this case, unlike the CEI South settlement, was entered into and endorsed by the OUCC and other parties representing multiple customer classes. Thus, he disagreed with any attempt to characterize the Settlement as favoring industrial customers to the detriment of residential customers.

Mr. Dauphinais stated that Mr. Inskeep's objection to the agreed reduction in Tier 1 demand levels for the Rate 631 class does not raise any valid concern. He explained that the process to progressively reduce the Tier 1 demand level for Rate 631 customers – both to bring imputed demand for cost allocation purposes closer to actual contract demand and to move eligible customers closer to the tariff minimum – was a feature of the 45772 Settlement. Mr. Dauphinais testified that the computation of adjustments to Tier 1 demand is correlated to reductions in the costs of legacy coal plants embedded in base rates and the agreed reduction in this case implements the 45772 Settlement. He explained that the difference between the 164 MW initially proposed by NIPSCO in its direct case and the 162 MW provided for in the Settlement is attributable to the substantial reduction in the revenue requirement under the Settlement. He said those reductions result in less coal plant-related costs being reflected in NIPSCO's base rates, and hence have a modest effect on the computation of new Tier 1 demand levels.

Mr. Dauphinais testified that Mr. Inskeep's position regarding the revenue distribution provision in the Settlement is not reasonable. He explained that NIPSCO's existing rate structure features substantial inter-class subsidies, with several rate classes paying rates in excess of system-average while the residential rate yields revenue significantly below a system-average return. He testified that several parties supported reductions in the current subsidies for the residential class and that the Settlement starts with the revenue distribution proposed by NIPSCO but then devotes a defined 25% component of the agreed decrease below NIPSCO's proposed revenue to reducing subsidies with the remainder allocated to all classes. Mr. Dauphinais testified that this provision mirrors the subsidy mitigation term in the 45772 Settlement. He stated that the CAC's effort to institutionalize a clear deviation from cost-based rates by maintaining the subsidy is unreasonable.

Ms. Schuepbach responded to Mr. Inskeep's allegations regarding cost shifting or subsidization by stating they are inaccurate for several reasons. First, the Commission found in Cause Nos. 45159 and 45772 that Rate 831/531 is not subsidized. Second, the proposed demand allocation to Rate 631 is consistent with the 45772 Order and the Settlement, which provides that future reductions to Tier 1 load and cost allocations will be correlated to further reductions in the costs of legacy coal assets reflected in NIPSCO's base rates. Third, Rate 831/531/631 has historically subsidized other customer classes and continues to do so. Ms. Schuepbach explained that, at a minimum, this rate is overallocated costs in production demand, transmission expenses, and FAC expenses. Ms. Schuepbach testified that Rate 631 is set to parity for rate mitigation (revenue distribution), meaning the rates will be set to collect revenues based on the ACOSS. However, Ms. Schuepbach stated that the ACOSS over-allocates expenses and Rate 631 customers are already paying more than their cost of service, particularly for legacy coal generation costs they no longer use.

Ms. Schuepbach disagreed with Mr. Inskeep that the system rate increase should be applied to each customer class. She explained that under the Settlement Agreement, Rate 631 is set to parity with a rate increase of 10.32% or $15.5 million. Mr. Inskeep, however, recommended a rate increase of 14.05% or $21.0 million (14.05% x $149,681,610), which would harm Rate 631 customers by increasing their revenue requirement by $5.6 million ($21,029,048 - $15,450,084). She expressed several concerns with the CAC's suggestion to apply the same rate increase to each customer class. First, she stated this approach goes against industry standard cost of service and ratemaking principles. Citing *Bonbright Principles of Public Utility Rates*, she testified that one of the described principles is the need for fair and equitable rates, or rates that represent the cost of service. Anything beyond cost-based rates means that there is subsidization among and/or within the customer classes. In addition, Ms. Schuepbach testified that the National Association of Regulatory Utility Commissioners' *Electric Utility Cost Allocation Manual* states that cost of service studies are one of the basic tools of ratemaking and explained there is no point to conducting a cost of service study if the system rate increase will be provided equally to all customer classes.

Second, Ms. Schuepbach testified that the CAC's proposal goes against NIPSCO's statement that the ACOSS is used as a guideline for class revenue levels and rate structures and its desire to move toward cost of service, while implementing moderation. She stated any proposal that is not moving classes towards their cost of service is compounding the subsidization issue, making ongoing subsidization worse for certain classes, like the residential class. She explained that if any revenue mitigation is done, it should be in a way that reduces subsidies and moves

classes closer to their actual cost of service, rather than amplifying and prolonging the subsidization problem.

Ms. Schuepbach testified that she agrees that the data centers need to pay their fair share of embedded costs for joining the NIPSCO system. While she agreed with Mr. Inskeep that the data center load is a major issue that needs to be addressed transparently and in detail with enforceability, she disagreed with Mr. Inskeep that the Settlement Agreement should be rejected or modified for the Commission to effectively deal with the issue, which is now pending in another proceeding.

Ms. Schuepbach concluded that the Settlement Agreement is fair, reasonable, and in the public interest. She testified that the Settlement terms keep NIPSCO profitable and will allow US Steel to remain a customer on the NIPSCO system. She stated that other customer classes benefit as well because of reductions in the overall system revenue requirement and the settlement class revenue allocators. She recommended that the Settlement Agreement be approved by the Commission.

10. Commission Discussion and Findings. At the outset, we recognize that the Commission previously approved most of the capital investment additions that NIPSCO proposes to include in its rate base in this proceeding.[14] These include the development and acquisition of four solar and solar plus storage facilities that make up approximately $2 billion (approximately 68%) of NIPSCO's rate base additions. NIPSCO's rate base request also reflects inclusion of approved TDSIC investments of $769.5 million (approximately 25% of the capital additions). The remaining portion of NIPSCO's rate base request (approximately 7%) relates to ongoing capital investment in other assets, including information technology and customer-driven capital work through new underground electric services, new business electric extensions, and new customer substations.

Even with the various preapproved projects discussed above, the record demonstrates that there were a number of highly contested issues in this Cause. Despite the complexity and number of issues, the Settling Parties reached a comprehensive agreement. Although it is opposed by one party, those joining or not opposing the Settlement Agreement and Addenda represent a wide variety of interests and included residential, commercial, and industrial customers. A complete copy of the Settlement Agreement is attached to this Order, including the schedules supporting the calculation of the agreed Settlement revenue requirement based on the 12-month period ending December 31, 2025 (Joint Exhibit A to the Settlement), the new depreciation rates (Joint Exhibit B to the Settlement), and the redacted Rate 631 contract demand (Confidential Joint Exhibit C to the Settlement). These attachments are incorporated into and made a part of this Order by reference.

The Settlement Agreement represents the Settling Parties' proposed resolution of the issues in this Cause. As the Commission has previously discussed, settlements presented to the Commission are not ordinary contracts between private parties. *U.S. Gypsum, Inc. v. Ind. Gas Co., Inc.* 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement

[14] *See*, Cause No. 45936 (IURC 1/17/2024), Cause No. 46028 (IURC 8/14/2024), Cause No. 46032 (IURC 8/21/2024), Cause No. 45557 (IURC 12/28/2021), and Cause No. 46025 (IURC 9/25/2024).

"loses its status as a strictly private contract and takes on a public interest gloss." *Id*. (quoting *Citizens Action Coal. Of Ind., Inc. v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coal.*, 664 N.E.2d at 406.

Further, any Commission decision, ruling, or order, including approval of a settlement must be supported by specific findings of fact and sufficient evidence. *U.S. Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coal. v. Public Service Co.*, 582 N.E.2d 330 (Ind. 1991)). The Commission's procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Before the Commission can approve the Settlement Agreement, the Commission must determine whether the evidence in this Cause sufficiently supports the conclusion that the Settlement Agreement is reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2 and that the Settlement serves the public interest.

The Commission has before it substantial evidence from which to determine the reasonableness of the terms of the Settlement Agreement on all issues, including Petitioner's rate base, methodology to be used in determining the agreed rate increase, allocation of the rate increase, rate design, ROE and capital structure, and the other terms of the Settlement Agreement, all of which we find are supported by the evidence and testimony presented. As discussed further below, the Settlement Agreement, along with its attachments and the Settling Parties' testimony and exhibits, provides substantive information from which to discern the basis for the components of the increase in NIPSCO's base rates and charges under the Settlement Agreement, and we find the evidence supports that they are reasonable. We also recognize that all but one party in the proceeding either support or do not oppose the Settlement Agreement, including NIPSCO, the OUCC, the Industrial Group, NLMK, U.S. Steel, the RV Group, Walmart, and LaPorte County. These parties represent varied and competing customer groups and interests, encompassing most (if not all) NIPSCO rate classes.

As detailed above, the Settling Parties made numerous compromises to reach an agreement. NIPSCO, in its initial case-in-chief provided evidence to support a revenue deficiency of $369 million, reflective of an overall 20.15% revenue increase. As shown by Paragraph B.1.(a) of the Settlement Agreement, the Settling Parties agree that NIPSCO's base rates should be designed to produce $2,086,642,669 prior to application of surviving Riders. The increase in base rates results in an increase from current base rates of $257,043,752 (approximately 16.75%), which is a decrease of approximately $111,616,865 (30%) from the amount originally requested by NIPSCO in its case-in-chief.

Based on the evidence presented, we approve the Settlement Agreement without modification and decline to reject the Settlement Agreement or make the modifications suggested by the CAC for the reasons set forth below.

A. <u>Reasonableness of Settlement Agreement</u>. The CAC argues that several of its concerns were inadequately addressed in the Settlement Agreement and therefore recommends the Commission reject the Settlement or substantially modify its terms. We address each of the CAC's major concerns below but, based on the evidence presented, we are not persuaded by the CAC's arguments to reject or modify the Settlement. The Settling Parties have

sufficiently shown that the Settlement provides reasonable resolutions to the disputed issues. We find the Settlement Agreement substantially reduces NIPSCO's requested relief, reasonably addresses Indiana's five pillars as set forth in Ind. Code § 8-1-2-0.6 ("Five Pillars") of affordability, reliability, resiliency, stability and environmental sustainability, and is consistent with the balancing this Commission has been charged to perform by the Indiana General Assembly.

1. Cost Allocation and Rate Design. The Settlement ACOSS reflects the settled revenue requirement, which remains consistent with the structure and methodologies of the cost of service study used by NIPSCO in its case-in-chief. The ACOSS uses a 4CP methodology to allocate production costs and a minimum system study to determine a customer component for distribution costs. In addition, while adopting NIPSCO's cost of service structure and methodologies, the Settlement also includes commitments by NIPSCO to study the applicability of certain classification and allocation methodologies in an Allocation Study and present them as part of its next general rate case.

The CAC acknowledged that except for the use of an updated revenue requirement and other limited modifications, such as the reduction to Rate 631's allocated demand, the Settlement ACOSS is essentially consistent with the structure and methodologies used by NIPSCO. However, the CAC asserted that this is an unreasonable and unbalanced resolution to the cost allocation issues raised by the CAC and other parties. In particular, the CAC disagreed with the Settling Parties' agreement that NIPSCO use a 4CP cost allocation method for production costs and asserted that a 12CP cost allocation method is more reasonable and should be adopted as it was for Duke in Cause No. 46038. The CAC also criticized the Settling Parties' adoption of NIPSCO's proposed allocation of the ITC and PTC benefits in base rates and in the FAC, instead recommending that the allocation of these benefits mirror the allocation that is ultimately adopted in this proceeding for the costs of generation and battery storage facilities. Finally, the CAC disagreed with the modification of Rate 631 Tier 1 demand that further reduces the production costs allocated to Rate 631.

The record establishes that NIPSCO's system peak occurs in the summer and that its system does not satisfy the three FERC tests that guide determination as to whether a change to a 12CP methodology is appropriate. In addition, the generation investments included in the Forward Test Year are driven by peak summer hours and allow NIPSCO to provide reliable service in all hours of the year. We also note that a key difference between NIPSCO's and Duke's electric service territories is the penetration level of natural gas heating for its residential customers. The comparatively lower use of electric heating in NIPSCO's service territory materially shifts the demand curve to the summer, bolstering NIPSCO's support of the 4CP methodology. NIPSCO, Duke, and CEI South all participate in MISO. The MISO seasonal construct, however, is not determinative of how each utility should allocate its production costs. The cost allocation appropriate for each utility is, and must be, a function of its cost to serve. The Settlement Agreement's reliance on the 4CP allocation methodology for production costs under the facts presented in this case is reasonable and supported by the record.

Regarding the agreed upon allocation of PTCs and ITCs in the Settlement Agreement, the record reflects disagreement among many of the parties on how these benefits should be allocated. As noted by the Settling Parties, the Settlement's proposed treatment is consistent with three prior Commission orders providing for the pass back of PTCs and ITCs to customers through NIPSCO's

FAC. NIPSCO has also agreed to conduct an Allocation Study to further address cost allocation issues in its next base rate case. CAC's arguments fail to recognize that energy must be generated by a solar facility to generate PTCs and that any adjustment for ITCs would likely be de minimis due to the continued residential class subsidy. Therefore, we are not convinced by CAC's arguments that the Settling Parties' agreement on the allocation of PTCs and ITCs is unreasonable.

The step down of Rate 631 Tier 1 allocated demand in the Settlement Agreement relates to reductions in coal plant-related costs being reflected in NIPSCO's base rates. This treatment is consistent with the methodology previously approved in the 45772 Order and we were not presented with sufficient reasons for this methodology to change. Therefore, we find that the incorporation of NIPSCO's ACOSS into the Settlement Agreement is reasonable and appropriate, and the resulting cost allocation in the Settlement Agreement is approved. While we find NIPSCO's ACOSS is supported by the evidence, we are encouraged by NIPSCO's commitment to conduct an Allocation Study to review its production allocation on an energy basis, particularly as the share of non-dispatchable resources in its generation portfolio increases. NIPSCO shall follow the terms of the Settlement Agreement, including Section 11(b) regarding production and distribution classification and allocation.

Finally, while not addressed in the CAC's testimony opposing the Settlement, Mr. Inskeep opposed in his direct testimony NIPSCO's recovery of the amortization expense associated with its Economic Development Rider from non-participating customers because the Rider benefits utility shareholders. However, as noted by Mr. Weatherford, the Commission has previously authorized NIPSCO with deferral accounting authority to recover in a future rate case the associated customer discounts in Cause No. 45159. Accordingly, we find the treatment proposed by NIPSCO, as incorporated in the Settlement Agreement, remains reasonable and should be approved.

2. <u>Revenue Distribution</u>. In the Settlement Agreement, the Settling Parties acknowledged that, as presented in NIPSCO's case-in-chief, certain rate classes are being subsidized by several other rate classes. Thus, the Settling Parties agreed to mitigate a portion of the subsidy concerns in a manner consistent with similar concerns that were raised and addressed in the 45772 Settlement.

The CAC noted that while the Settlement Agreement provides for a 30.3% reduction to the revenue requirement from NIPSCO's original filing, residential customers will experience only a 23.6% reduction to their revenue requirement relative to NIPSCO's case-in-chief. Mr. Inskeep argued that this results in an unbalanced Settlement mitigation that benefits non-residential customers. As an alternative, Mr. Inskeep proposed assigning the same percentage increase to each existing customer class, i.e., equal to the system average increase. Then, prior to NIPSCO's next rate case, NIPSCO could conduct a holistic examination to more accurately identify existing cross-subsidization occurring in rates and propose the appropriate cost allocation modifications and mitigation steps to address any identified cross-subsidies, while taking into consideration gradualism and other important public policy objectives.

We recently modified the revenue distribution in an opposed settlement by adopting a lower cap on the agreed system average overall increase for the residential class in CEI South's last rate case, Cause No. 45990. In that case, the tendered settlement limited the increase to each

class to no more than 1.35 times the system-average increase, and we found it appropriate to narrow that band to no more than 1.15 times system average. *CEI South*, Cause No. 45990 at 114-115 (IURC Feb. 3, 2025). Under the Settlement here, however, the residential increase of 14.75% is only 1.05 times the system average of 14.05% and well within the constraint we found appropriate in CEI South's rate case. Pet. Ex. 16-S, Att. 16-S-A at 1. In that case, we also acknowledged that "[a]ffordability is a key consideration across all customer classes, and the desire to provide affordability across the board supports a revenue requirement increase that is as evenly borne as practical, while considering any subsidies that may be identified by the ACOSS." *CEI South*, Cause No. 45990 at 115.

The record is clear that, under the analysis of multiple cost of service experts in this Cause, NIPSCO's residential class is being subsidized by the rates paid by other customer classes. In addition, even under the 12CP allocation methodology proposed by the OUCC on direct, and as the CAC now proposes, the residential class would continue to receive a $99 million subsidy. We are not persuaded by the CAC's arguments and find that the CAC's recommended across the board system average would only perpetuate and potentially grow the residential class subsidy, undermining customer affordability in deviation from cost causation principles.

Accordingly, we find that the Settlement Agreement reflects fair and appropriate compromises made by representatives of the majority of customer classes, while recognizing the policy of gradualism, to reach a distribution that is as evenly borne as practical considering the identified interclass subsidy. The agreed revenue distribution as presented in the Settlement Agreement is reasonable, balanced, and approved.

3. Multi-Family Rate. Under the Settlement Agreement, NIPSCO's proposed multi-family rate will not be implemented. Instead, NIPSCO agrees to collect additional data on residential customer housing to further identify multi-family customers and analyze the cost differentials between single- and multi-family customers for consideration in its next base rate case. NIPSCO also agrees to meet with interested stakeholders and share its analysis prior to filing its next base rate case.

The CAC asserted that by not adopting NIPSCO's multi-family rate, the Settlement will significantly harm multi-family customers and produce rates that are unjust, unreasonable, and in excess of what NIPSCO considered to be the cost to serve such customers, even prior to the reduction in revenue requirement included in the Settlement.

The evidence demonstrates that both the OUCC and the CAC took issue with the scope and robustness of NIPSCO's data to support the proposed multi-family rate and how many multi-family customers are in NIPSCO's territory. However, while the OUCC opposed approval of the multi-family rate, the CAC recommended approval along with a recommendation that NIPSCO conduct a more comprehensive evaluation to be provided in its next rate case.

Based on the evidence presented, we find the Settlement Agreement reasonably resolves the parties' dispute by foregoing implementation of the multi-family rate in this Cause but committing NIPSCO to further study its multi-family customers. We find this resolution reasonable, especially given the OUCC's concern that creation of the multi-family rate could create more interclass subsidies. As Mr. Deupree noted, the evidence is insufficient to conclude

that implementing the multi-family rate disproportionately harms lower-income households because it has not been demonstrated that all, or even most, of NIPSCO's multi-family customers are low income customers. Thus, we find NIPSCO's agreement to continue collecting data, including using information from Advanced Metering Infrastructure ("AMI") that is anticipated to facilitate these efforts after being fully deployed in NIPSCO's service territory, should provide greater insight for purposes of potentially facilitating such a proposal in future proceedings.

4. Low Income Program. The Settlement provides for approval of NIPSCO's proposed low income program with the following changes: (1) NIPSCO will modify the program from an opt-out program to a voluntary, opt-in program; and (2) NIPSCO will make an annual, below the line, shareholder contribution of $1,500,000.

The CAC recommended the Commission approve the low income program NIPSCO proposed in its case-in-chief, as modified by Mr. Inskeep's recommendations in his direct testimony. Mr. Inskeep stated that the changes agreed to in the Settlement dramatically reduce the funding for the program, meaning eligible customers will receive substantially smaller benefits. Thus, he concluded that NIPSCO's original proposal provided program design and funding levels that are more reasonable to address affordability.

Under the Settlement Agreement, NIPSCO's proposed low income program has been modified in response to concerns raised by the OUCC as well as consideration of prior Commission orders regarding ratepayer-funded bill assistance programs. As presented by the Settling Parties, the low income program remains an important measure intended to address utility affordability for residential customers who face income challenges. The OUCC noted that the program as modified will reduce the potential impact on ratepayers, including low income customers, while still enabling assistance from customers who choose to participate in the assistance program. In addition, NIPSCO's shareholder contribution has substantially increased from its case-in-chief (from $400,000 per year to $1,500,000 per year) and will provide bill assistance to customers in need. When the Settlement Agreement is considered in its entirety, we find the agreed low income program balances the consumer parties' interests and concerns, including those expressed by the CAC, with NIPSCO's interest in providing bill assistance for its low income customers. We, therefore, find the stipulated low income program is reasonable and should be approved.

5. Data Centers. While several parties advocated for the creation of a subdocket to address issues related to new large load customers, the Settling Parties acknowledged in the Settlement that NIPSCO has made a filing with the Commission related to its strategy to serve such customers. NIPSCO expressed its intent for any large load customer with which it enters into a contract for electric service will commit to pay the direct, incremental costs associated with serving that load and some portion of NIPSCO's existing electric system. If NIPSCO should enter into such a contract, NIPSCO also commited to making a timely filing to pass back to existing customers the revenues collected that are related to the recovery of costs associated with the existing electric system. Additionally, while other parties are not precluded from making arguments in other dockets related to large load customers, NIPSCO is precluded from arguing it should not pass back any portion of these identified revenues.

The CAC argued the Settlement does not adequately resolve the issues raised by several parties with respect to new large load customers like data centers. Mr. Inskeep stated the Settlement fails to meaningfully address data centers, which he contended should pay (like other ratepayers) the full embedded cost of service – not merely "direct, incremental" costs and "some portion" of embedded costs. Mr. Inskeep argued that a subdocket to holistically examine issues would be a more appropriate forum to collect and weigh the evidence and determine the appropriate path forward, rather than approving a vaguely worded term containing inaccurate statements expressing an intention for further discriminatory treatment.

The evidence demonstrates that NIPSCO has not entered into any contract for electric service with a large load customer and the Forward Test Year in this case does not include any costs or expected revenues associated with data center load. Thus, we agree that the CAC's concerns regarding cost recovery and discriminatory treatment, which are hypothetical and premature at this time, are best addressed in a regulatory filing related to the approval of any special contract. A subdocket to this Cause to address data centers is neither necessary nor appropriate. As noted by the OUCC, the Settlement Agreement preserves flexibility in considering individual proposals from potential data center customers, maintains the ability of parties to raise issues in other proceedings, and recognizes NIPSCO's commitment to ensure that the addition of these new customers does not result in higher costs for existing customers. NIPSCO is also precluded from contesting the pass back of large load contract revenue related to the recovery of existing electric system costs. Accordingly, we find that the Settlement Agreement maps out a reasonable approach for addressing the issues raised regarding potential new large load customers in NIPSCO's service territory.

6. <u>Residential Customer Affordability</u>. The CAC generally contended the Settlement is inconsistent with Indiana's affordability pillar and public interest. Mr. Inskeep asserted that many of NIPSCO residential customers will experience rate shock and accelerating unaffordability. He stated the Settlement discards some of the most critical residential affordability protections initially proposed by NIPSCO, such as ratepayer-funded income-qualified bill assistance, a multi-family rate, and limiting the residential class rate increase to the system average increase. He asserted that the modest consumer protection provisions included in the Settlement do little to mitigate the unprecedented rate shock residential customers will experience.

As noted earlier, the primary driver of NIPSCO's requested rate increase is the capital projects that have received preapproval by the Commission, which limits the ability to mitigate the overall rate increase. The Settlement Agreement in this Cause results in over $111 million in reductions to NIPSCO's as-filed revenue requirement and an over $30 million reduction to the proposed revenue increase for the residential class. The Settlement also reflects a number of measures intended to address affordability and residential customer needs, including elimination of the $50 customer deposit for NIPSCO's gas and electric customers receiving bill assistance through LIHEAP; waiver of NIPSCO's $90 electric reconnection charge for electric customers who are disconnected for non-payment of charges (beginning no later than implementation of Step 2 rates); delay of disconnection of electric service if temperatures are below 20 degrees or above 90 degrees on the scheduled day of disconnection or if forecasted the following two days; and no increase to the monthly residential customer charge of $14. The Settlement also reflects the creation of a bill assistance program for NIPSCO's low income electric customers funded by

voluntary customer contributions and a significant annual $1.5 million contribution from NIPSCO shareholders. In addition to these benefits, NIPSCO's commitment to holistically study its cost of service classifications and allocations in an Allocation Study have the potential to further reduce residential rates in the future. Taken together, we find the Settlement Agreement reasonably addresses customer affordability consistent with Indiana's Five Pillars and is in the public interest.

B. ARP for Remote Disconnection/Reconnection. The Settling Parties agree in Section B.14. of the Settlement Agreement to the approval of the ARP for remote disconnect/reconnect and Mr. Inskeep did not oppose this portion of the Settlement Agreement.

Ms. Whitehead testified that NIPSCO requests approval of an ARP to waive the requirements in 170 IAC 4-1-16(f) and to permit remote disconnection in lieu of an in-person visit by a utility representative prior to disconnection. She explained that NIPSCO received approval for its AMI Project through its electric TDSIC Plan approved in the Commission's December 28, 2021 Order in Cause No. 45557. NIPSCO expects approximately 205,000 of its electric customers will have AMI meters installed by the end of the Forward Test Year (i.e., December 31, 2025). She said AMI meter technology provides for the efficient and safe remote capability to disconnect and reconnect electric service.

Ms. Whitehead explained NIPSCO's business practice as it relates to customer contact information like phone numbers and email addresses, how customers are currently notified of a service disconnection due to non-payment, and the proposed procedure for notifying customers of a service disconnection for non-payment using AMI technology. She noted that certain customers will be exempt from remote disconnection, including medical alert customers, AMI opt-out customers, and those customers without documented telephone numbers or email addresses. Ms. Whitehead testified that if the ARP is approved, NIPSCO will undertake a campaign to notify its customers of its ability to remotely disconnect/reconnect upon our approval of the requested waiver.

In his direct testimony, but not his settlement opposition testimony, Mr. Inskeep opposed NIPSCO's remote disconnection proposal because it would make it easier for utilities to disconnect residential ratepayers without adequately informing them through an on-premises visit. He argued that NIPSCO's proposed ARP for remote disconnection is inconsistent with the requirements of Ind. Code ch. 8-1-2.5. No other party opposed the request, but Ms. Paronish recommended enhancements to NIPSCO's communications plan, including, to the extent NIPSCO has the information, utilizing all three communication mechanisms – a phone call, a text message, and an email communication – to contact a customer prior to disconnection. She also proposed additional communication language and methods to notify customers that service disconnection will be conducted remotely.

On rebuttal, Ms. Whitehead explained that NIPSCO was modifying its communications plan based on the OUCC's recommendations. She said, as modified, NIPSCO's customers will be adequately informed that their service is being disconnected for non-payment. Ms. Whitehead also responded to Mr. Inskeep's concerns, explaining why NIPSCO's requested waiver of the requirements in 170 IAC 4-1-16(f) is in the public interest and meets the statutory criteria. She also provided Table 1 in Petitioner's Exhibit 2-R, which details NIPSCO's response to each

additional communication method proposed by the OUCC and provided NIPSCO's modification to the language in its messaging.

Given that Petitioner's waiver request is part of an ARP, in addition to our overall approval of the Settlement Agreement, Ind. Code § 8-1-2.5-6(a)(1)(A) requires the Commission to determine whether approval of the proposed ARP is in the public interest by considering the following four criteria enumerated in Ind. Code § 8-1-2.5-5(b):

> (1) whether technological or operating conditions, competitive forces, or the extent of regulation by other state or federal regulatory bodies render the exercise, in whole or in part, of jurisdiction by the commission unnecessary or wasteful;
>
> (2) whether the commission's declining to exercise, in whole or in part, its jurisdiction will be beneficial for the energy utility, the energy utility's customers, or the state;
>
> (3) whether the commission's declining to exercise, in whole or in part, its jurisdiction will promote energy utility efficiency;
>
> (4) whether the exercise of commission jurisdiction inhibits an energy utility from competing with other providers of functionally similar energy services or equipment.

The Commission's rule at 170 IAC 4-1-16(f) provides that, prior to disconnection of electric service, a NIPSCO employee is required to, among other things, make an on-site premises visit. The record shows that, due to the advancement in technology and through the use of AMI, there are safer and more effective ways to notify a customer of potential disconnect due to nonpayment and to ultimately disconnect the customer than what was historically available when the rule was promulgated. Modern technology allows NIPSCO to notify the customer multiple times and in many different forms in the event of a potential disconnect. Further, through the use of AMI and remote connect/disconnect capability, NIPSCO does not need to be physically present on the customer's premises to connect or disconnect service, promoting efficiency. Thus, the goals of 170 IAC 4-1-16(f) – to sufficiently notify a customer of potential disconnect and to identify oneself while on a customer's property – can be achieved in a safer and more effective way through the use of modern technology.

The record also reflects that Commission approval of NIPSCO's proposed ARP will be beneficial for the utility, its customers, and the state, as NIPSCO will be able to complete disconnects and reconnects more safely, quickly, and efficiently through the remote capabilities of AMI than through the traditional truck roll and field personnel being dispatched to the customer's premise. Remote disconnection will improve safety for NIPSCO's workers and remote reconnection will support customer safety by restoring service faster.

We also find that the exercise of the Commission's jurisdiction would inhibit NIPSCO from competing with other providers of functionally similar services or equipment insofar as it would deny NIPSCO a waiver of a requirement that has been waived for other similarly situated utilities in the State of Indiana. We have approved similar waivers for CEI South in Cause No.

45990, Duke in Cause No. 45253, Indiana Michigan Power Company in Cause No. 45567, and AES Indiana in Cause No. 45911.

Based on the evidence of record, we find that NIPSCO's ARP to provide a waiver of the requirement of an on-site premises visit prior to disconnection, as proposed and modified on rebuttal, is in the public interest and approve it. NIPSCO shall pursue the three-month customer communication plan outlined in Ms. Whitehead's direct testimony, with the additional OUCC-recommended communication methods and language as agreed to in Ms. Whitehead's rebuttal and agreed to by the Settling Parties in Section B.14. of the Settlement Agreement.

C. Ultimate Findings on Settlement. Based on the evidence presented, we find nothing presented by the CAC in its settlement opposition evidence causes the Commission to find the Settlement should be modified or rejected. While the Settlement did not result in an outcome that perfectly aligns with the CAC's litigated position, the same can be said for all parties to this Cause. Nevertheless, the Settlement Agreement does reasonably address the revenue, cost allocation, and rate design matters in the context of all parties' litigated positions, including the CAC.

The Settlement Agreement results in a reasonable revenue increase, which reflects a fair return of and on capital investment made by NIPSCO if the utility is operated efficiently and enables NIPSCO to continue to provide reliable service to its customers on a sound financial foundation. The evidence in this Cause sufficiently supports the conclusion that the Settlement Agreement is within the range of potential outcomes and represents a fair resolution of the issues presented within the guardrails of the Five Pillars. Accordingly, based on the evidence presented, we find that the Settlement Agreement is reasonable, supported by substantial evidence, in the public interest and is approved without modification.

The revenue allocation shall be as set forth in the Settlement and Petitioner's Exhibit 16-S, Attachment 16-S-A. This revenue allocation is based upon the projected rate base and capital structure; the actual revenue allocation shall be based upon the actual rate base, and capital structure at the time, following the multiple-step mitigation process set forth in the Settlement. We find that based upon the projected capital structure and rate base, the rates set forth in Attachment 16-S-B and the tracker allocations set forth in Attachment 16-S-D of Petitioner's Exhibit 16-S, are reasonable and should be approved. We further find that the depreciation accrual rates set forth in Joint Exhibit B to the Settlement Agreement should be approved.

NIPSCO shall be authorized to increase its base rates and charges in multiple steps, calculated to produce additional annual base rate revenue of $257,043,752, total base rate revenue of $2,086,642,669, and total net operating income of $651,868,680. This is based upon Forward Test Year ending net original cost rate base of $9,129,813,441 as follows:

Net Utility Plant	$7,396,151,653
Schahfer Units 14, 15, 17, and 18 Retirement	$661,125,225
WAM – Regulatory Asset	$28,237,008
Renewable Energy Joint Venture Investments	$772,866,616
Cause Nos. 45772 & 45159 Remainder	$24,524,961
Electric TDSIC Cause Nos. 44733 and 45557	$18,679,396
Wholly Owned Solar Farms – Regulatory Asset	$99,839,760
Materials & Supplies	$112,720,299
Production Fuel	$15,668,523
Original Cost Rate Base	**$9,129,813,441**

We further find that a fair return should be authorized based upon this net original cost rate base and a projected weighted average cost of capital of 7.14%, as follows:

	Total Company Capitalization	Cost %	Weighted Average Cost %
Common Equity	$7,718,129,223	9.75%	5.17%
Long-Term Debt	$5,468,979,284	5.20%	1.95%
Customer Deposits	$59,885,295	5.63%	0.02%
Deferred Income Taxes	$1,691,723,532	0.00%	0.00%
Post-Retirement Liability	($7,491,885)	0.00%	0.00%
Prepaid Pension Asset	($372,308,313)	0.00%	0.00%
Post-1970 ITC	$174,612	7.87%	0.00%
Totals	**$14,559,091,748**		**7.14%**

We further find that NIPSCO shall be authorized to increase its base rates and charges in multiple steps, calculated to produce additional annual base rate revenue of $257,043,752, total base rate revenue of $2,086,642,669, and total net operating income of $651,868,680 as follows:

Original Cost Rate Base	$ 9,129,813,441
Times: Weighted Average Cost of Capital	7.14%
Net Operating Income	$651,868,680
Less: Pro forma Net Operating Income	$ 418,038,218
Net Revenue Increase Required	$ 233,830,462
Gross Revenue Conversion Factor	1.336175
Recommended Gross Revenue Increase Required	$313,139,816
Less: NOI Neutral Revenue Requirement Associated with Fuel Reduction	$56,096,064
Petitioner's Total Recommended Revenue Increase Required	$257,043,752
Recommended Percentage Increase over Revenues Subject to Increase at Present Rates	14.05%

The rate increase authorized herein should be implemented in multiple steps as set forth below:

(a) Step 1 Rates Subject to Refund: Step 1 rates shall be implemented on a services rendered basis as soon as possible following the issuance of this Order and approval of NIPSCO's new tariffs by the Commission's Energy Division and will be based on actual net plant certified to have been completed and placed in service no later than May 31, 2025, except for the Fairbanks and Gibson solar projects, which may be placed in service later, as set forth herein. Step 1 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of May 31, 2025. Prior to implementation of Step 1 rates, NIPSCO will certify the net original cost rate base and current capital structure as of May 31, 2025, and calculate the Step 1 rates using those certified figures. For purposes of Step 1 rates, "certify" means NIPSCO states in a filing with the Commission under this Cause the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of May 31, 2025. NIPSCO will serve all parties to this proceeding with its certification. The Settling Parties, and other interested parties to this proceeding, will thereafter have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. All parties to this proceeding shall be permitted to conduct discovery to verify relevant construction costs and in service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual net plant in service as of May 31, 2025, and rates will be trued up, with carrying charges, retroactive to the date Step 1 rates were put into place.

(b) Step 2 Rates Subject to Refund: Step 2 rates shall be implemented on a services rendered basis as soon as possible after the end of the Forward Test Year and will be based on actual net plant certified to have been completed and placed in service no later than December 31, 2025. Step 2 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2025. Prior to implementation of Step 2 rates, NIPSCO will certify the net original cost rate base and current capital structure as of December 31, 2025 and calculate the Step 2 rates using those certified figures. For purposes of Step 2 rates, "certify" means NIPSCO states in a filing with the Commission under this Cause the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2025. NIPSCO will serve all parties to this proceeding with its certification. The Settling Parties, and other interested parties to this proceeding, will thereafter have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. The Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 rates were put into place.

(c) Additional Interim Phases: In the event Fairbanks and/or Gibson are not in service by the general rate base cutoff for Step 1 (May 31, 2025) but come into service on or before the general rate base cutoff for Step 2 (December 31, 2025), up to two additional steps may occur to include these projects in rates earlier than Step 2 (end of the Forward Test Year). The compliance filing(s) for the additional step(s) will be based on the addition to rate base and associated

depreciation expense for Fairbanks or Gibson (whichever the case may be) upon the filing of a certification that the plant is in service. The rates will use the capital structure used for Step 1 rates. NIPSCO shall file a certification under this Cause that the asset is in service and serve a copy of such certification upon all parties to this Cause. The rates will be implemented on a services rendered basis and take effect on the same interim-subject-to-refund basis as Step 1 and Step 2 rates, with the same period for other parties to raise objections and for a hearing to potentially be conducted. To the extent Fairbanks and/or Gibson are not in service by May 31, 2025, but are in service by the time of the Step 1 compliance filing in this Cause, NIPSCO may include the plant in Step 1 rates calculated as provided in this paragraph, subject to potential objections, true-up, and all other matters described above with respect to Step 1 rates.

D. Five Pillars. Through Ind. Code § 8-1-2-0.6, the Indiana General Assembly declared it is the continuing policy of the state that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider each of the Five Pillars of electric utility service: reliability, affordability, resiliency, stability, and environmental sustainability. As such, the Five Pillars have served as the lens through which the Commission has viewed all parties' requested relief in this Cause, including the Settlement Agreement. Per the Legislature's directive, we have considered and evaluated each of the Five Pillars in making our determinations in this case, and our considerations are discussed throughout the findings set forth above.

We find that our approval of the Settlement Agreement properly addresses utility service affordability for present and future generations and balances the Five Pillars. The Settlement Agreement reduces the requested overall revenue requirement, which supports affordability while allowing NIPSCO to maintain its system reliability, resiliency and stability. A significant portion of NIPSCO's requested revenue increase in this case is driven by preapproved projects and TDSIC projects, which contribute to NIPSCO's reliability, resiliency, stability, and environmental sustainability. The Settlement Agreement also furthers NIPSCO's generation transition, which supports environmental sustainability. It also provides additional options for low-income customers, supporting affordability for all customers.

E. Other Matters. The Settlement includes two Addendums that do not require Commission approval because they have no impact on NIPSCO's rates established in this Cause. While we need not approve the Addendums, we note that based on the evidence presented, the terms reasonably address concerns raised by the RV Group and LaPorte County.

In addition, while not part of the Settlement, we note that NIPSCO also committed to assembling a collaborative of educational institutions in response to the numerous comments offered by school districts regarding the challenges presented by electric rate increases. Pet. Ex. 21. NIPSCO committed to providing these entities with information about opportunities to participate in the NIPSCO demand side management oversight board and current program offerings or proposals for new program opportunities from which educational institutions may benefit.

11. Effect of Settlement Agreement. The parties agree that the Settlement Agreement is not to be used as precedent in any other proceeding or for any other purpose except to the extent necessary to implement or enforce its terms; consequently, with regard to future citation of the

Settlement Agreement or of this Order, the Commission finds our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, (IURC March 19, 1997).

12. Confidentiality. NIPSCO filed motions for protection and nondisclosure of confidential and proprietary information on September 12, 2024, and January 29, 2025, both of which were supported by affidavits showing certain documents to be submitted to the Commission contain trade secrets as defined under Ind. Code § 23-2-3-2. A docket entry was issued on each motion finding such information to preliminarily be confidential, after which the information was submitted under seal. The Commission finds all such information preliminarily granted confidential treatment is confidential under Ind. Code §§ 5-14-3-4 and 8-1-2-29, is exempt from public access and disclosure by Indiana Law and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The Settlement Agreement, a copy of which is attached to this Order, is approved.

2. Petitioner is authorized to increase its rates and charges for electric utility service in multiple steps as described in Finding Paragraph 10.C. above.

3. New depreciation rates applicable to NIPSCO's common and electric plant are approved as set forth in this Order.

4. Petitioner shall file new schedules of rates and charges along with its revised tariff under this Cause consistent with the Settlement Agreement and the rates and charges approved above for approval by the Commission's Energy Division.

5. Petitioner shall certify its net plant, original cost rate base, and capital structure at May 31, 2025 (Step 1) and December 31, 2025 (Step 2) and calculate the resulting rates and charges, which shall be made effective upon filing in accordance with the findings herein, subject to being contested and trued-up consistent with the Settlement Agreement.

6. To the extent that either Fairbanks or Gibson is not completely in service as of May 31, 2025 but is in service before December 31, 2025, Petitioner is authorized to implement up to two additional interim phases to its increase, based upon the Step 1 capital structure as described in Finding Paragraph 10.C. above. To the extent Fairbanks and/or Gibson are not in service by May 31, 2025, but are in service by the time of the Step 1 compliance filing in this Cause, NIPSCO may include the plant in the calculation of Step 1 rates as provided in this Order.

7. Petitioner is authorized to file updated factors for its rate adjustment mechanisms in accordance with this Order, and such changes shall be effective simultaneously with approval of NIPSCO's new basic rates.

8. Petitioner's proposed form of Electric Service Tariff is approved, consistent with the Settlement Agreement and this Order, inclusive of the associated General Rules and Regulations and Standard Contracts.

9. Petitioner is directed to file under this Cause all information required by the Settlement Agreement.

10. The information filed in this Cause pursuant to Petitioner's motions for protection and nondisclosure of confidential and proprietary information is deemed confidential under Ind. Code § 5-14-3-4, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

11. This Order shall be effective on and after the date of its approval.

HUSTON, BENNETT, FREEMAN, VELETA, AND ZIEGNER CONCUR;

APPROVED: JUN 26 2025

I hereby certify that the above is a true
and correct copy of the Order as approved.

_____ on behalf of
Dana Kosco
Secretary of the Commission

OFFICIAL
EXHIBITS

IURC JOINT - Settling Parties
EXHIBIT No. 1
3-25-25 AT
REPORTER

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RETAIL RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS (BOTH EXISTING AND NEW); (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING, BUT LIMITED TO, AUTHORITY TO CAPITALIZE AS RATE BASE ALL EXPENDITURES FOR IMPROVEMENTS TO PETITIONER'S INFORMATION TECHNOLOGY SYSTEMS THROUGH THE DESIGN, DEVELOPMENT, AND IMPLEMENTATION OF A WORK AND ASSET MANAGEMENT ("WAM") PROGRAM, TO THE EXTENT NECESSARY; AND (5) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE PARTIAL WAIVER OF 170 IAC 4-1-16(f) AND PROPOSED REMOTE DISCONNECTION AND RECONNECTION PROCESS AND, TO THE EXTENT NECESSARY, IMPLEMENTATION OF A LOW INCOME PROGRAM.	CAUSE NO. 46120

STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement ("Agreement") is entered into as of this 7th day of February, 2025, by and among Northern Indiana Public Service Company LLC ("NIPSCO"), the Indiana Office of Utility Consumer Counselor ("OUCC"),

NIPSCO Industrial Group ("Industrial Group"),[1] NLMK Indiana, United States Steel Corporation ("US Steel"), Walmart Inc. ("Walmart"), and RV Industry User's Group ("RV Group") (collectively the "Settling Parties").[2] The Settling Parties, solely for purposes of compromise and settlement, stipulate and agree that the terms and conditions set forth below represent a fair and reasonable resolution of the issues in this Cause subject to incorporation into a Final Order of the Indiana Utility Regulatory Commission ("Commission") without any modification or condition that is not acceptable to each of the Settling Parties regarding the issues resolved herein. In particular, the Settling Parties agree that the rate design and cost allocation methodology set forth in the Settlement Agreement and supporting testimony was a material inducement to entering into the settlement, and a modification of those terms could materially change the benefit of the Settling Parties' bargain. The Settling Parties agree this Agreement resolves all disputes, claims, and issues arising from the electric general rate case proceeding currently pending in Cause No. 46120 as among the Settling Parties. The Settling Parties agree that matters for which NIPSCO requested relief in this Cause that are not addressed herein, but were expressly supported by testimony, are resolved as NIPSCO proposed, or if modified in rebuttal, as modified in

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1 The Industrial Group is comprised of BP Products North America, Inc., Cleveland Cliffs Steel LLC, Linde, Marathon, and USG Corporation.

2 The Board of County Commissioners of LaPorte County ("LaPorte County"), and United Steel, Paper and Forestry, Rubber Manufacturing, Energy, Allied Industrial and Service Workers International Union AFL-CIO/CLC and its Locals 12755 and 13796 ("USW"), agreed to not oppose. LaPorte County and USW reserve their rights to respond to testimony opposing the Agreement.

rebuttal without waiving the right to challenge such resolution prospectively except as facts and circumstances may allow.

A. Background[3]

1. NIPSCO's Current Basic Rates and Charges. NIPSCO's current electric basic rates and charges were approved pursuant to the Commission's August 2, 2023, Order in Cause No. 45772 (the "45772 Rate Case Order"), wherein the Commission approved a Stipulation and Settlement Agreement, including a Stipulation and Settlement Agreement between NIPSCO and its industrial customers on Rate 831/531 implementation (the "Rate 831/531 Modification Settlement").[4]

2. NIPSCO's Current Depreciation Accrual Rates. NIPSCO's current common and electric depreciation rates were approved in the 45772 Rate Case Order.

3. NIPSCO's Fuel Adjustment Clause ("FAC") Proceedings. NIPSCO files a quarterly Fuel Adjustment Clause ("FAC") proceeding in accordance with Ind. Code § 8-1-2-42(d) in Cause No. 38706-FAC- XXX to adjust its rates to account for fluctuation in its fuel and purchased energy costs. Historically, NIPSCO has agreed that the OUCC and other interested parties should have thirty-five (35) days to review NIPSCO's FAC filings. NIPSCO agrees that the thirty-five (35) day review period shall continue.

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[3] This "Background" section is included to provide context for the Agreement and does not reflect any term of the Settling Parties' agreement.

[4] The Rate 831/531 Modification Settlement was entered into on September 12, 2022 by and between NIPSCO, Cleveland-Cliffs Steel LLC, Linde, Inc., BP Products North America, Inc., Cargill, Inc., NLMK Indiana, Pratt Paper (IN), LLC, and US Steel.

4. This Proceeding. On September 12, 2024, NIPSCO filed its Verified Petition with the Commission requesting the Commission issue an order: (1) authorizing NIPSCO to modify its retail rates and charges for electric utility service through the phase-in of rates; (2) approving new schedules of rates and charges, general rules and regulations, and riders; (3) approving revised common and electric depreciation rates applicable to its electric plant in service; (4) approving necessary and appropriate accounting relief, including, but not limited to, authority, to the extent necessary, to capitalize as rate base all expenditures for improvements to Petitioner's information technology systems through the design, development, and implementation of the WAM program;[5] (5) approving an alternative regulatory plan for a partial waiver of the requirements of 170 IAC 4-1-16(f); (6) approval of a new low income program, including through an alternative regulatory plan if necessary; (7) authorizing NIPSCO to implement temporary rates; and (8) approving other requests as described in the Verified Petition. NIPSCO filed its case-in-chief testimony and exhibits on September 12, 2024. On December 19, 2024, the OUCC and intervenors filed their respective cases-in-chief. On January 16, 2025, NIPSCO filed its rebuttal testimony and exhibits, and the OUCC, CAC, Industrial Group, US Steel, NLMK, and RV Group filed cross-answering testimony and exhibits.

[5] The same request had been made in Cause No. 46025. The relief sought in that Cause was unopposed, but the request remained pending as of the filing of NIPSCO's Verified Petition. The Commission approved NIPSCO's request in its September 25, 2024 Order in Cause No. 46025.

As discussed within NIPSCO's Verified Petition and the testimony of various parties including NIPSCO, since the 45772 Rate Case Order, NIPSCO has brought one (1) solar facility online (Cavalry Solar Plus Storage) and anticipates three (3) solar facilities (Dunn's Bridge II Solar Plus Storage, Fairbanks Solar, and Gibson Solar) to come online by the end of the Forward Test Year.[6] NIPSCO also plans to retire Schahfer Generating Station Units 17 and 18 by the end of the Forward Test Year. NIPSCO seeks to change its rates to reflect the effects, including benefits, of these projects and retirements. Since the end of the test year in Cause No. 45772 and the end of the Forward Test Year in this case, NIPSCO projects its net original cost rate base will grow by nearly $3 billion.

NIPSCO seeks to revise its existing rates to address the changing energy marketplace, NIPSCO's generation transition, and to provide revenues adequate to cover its necessary and reasonable operating expenses and permit NIPSCO to earn a fair return upon the fair value of its property. NIPSCO's supporting evidence in this Cause indicates that revisions to NIPSCO's rates are sought to afford NIPSCO an

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[6] Dunn's Bridge II Solar Plus Storage (originally approved in Cause No. 45462, modification approving wholly owned structure in Cause No. 45936) has an aggregate nameplate capacity of approximately 435 MW solar plus 75 MW energy storage. NIPSCO anticipates receiving power in Quarter 1, 2025 and is included in rate base in this proceeding. Fairbanks Solar (originally approved in Cause No. 45511, modification approving wholly owned structure in Cause No. 46028) has an aggregate nameplate capacity of approximately 250 MW. NIPSCO anticipates receiving power in Quarter 2, 2025 and is included in rate base in this proceeding. Gibson Solar (originally approved in Cause No. 45926, modification approving wholly owned structure in Cause No. 46032) has an aggregate nameplate capacity of approximately 200 MW. NIPSCO anticipates receiving power from this facility in Quarter 3, 2025 and is included in rate base in this proceeding.

opportunity to recover its operating expenses and earn a fair return on the fair value of its property used and useful in providing service to its customers. NIPSCO further believes that the proposed rate changes will also enable NIPSCO to attract capital required for additions, replacements, and improvements to its Utility Property and to comply with regulatory mandates and otherwise provide adequate and reliable service. Intervenors took issue with multiple aspects of the NIPSCO rate filing in their responsive testimony.

B. Settlement Terms

1. Revenue Requirement and Net Operating Income.

(a) Revenue Requirement. The Settling Parties agree that NIPSCO's Step 2 base rates will be designed to produce revenue at proposed rates of $2,086,642,669 prior to application of surviving Riders.[7] This Revenue Requirement represents an increase of $257,043,752 from current rates. The agreed upon Revenue Requirement amounts to a reduction of $111,616,865 (30.28%) from the revenue requirement NIPSCO requested in its case-in-chief ($2,198,259,534). The Settling Parties agree the settlement Revenue Requirement reflects the depreciation study and accrual rates and amortization as discussed below. Joint Exhibit A attached hereto represents

[7] In this Agreement, as described in Section 10(b) below, "Step 2" shall refer to the ultimate step of rate implementation based upon the end of the Forward Test Year, even though as set forth herein, there could be more than two steps to the increase.

the schedules supporting the calculation of the agreed settlement Revenue Requirement based on the 12-month period ending December 31, 2025.

(b) Net Operating Income. The Settling Parties agree that the settlement Revenue Requirement in Paragraph B.1(a) above results in a proposed authorized net operating income of $651,868,680.

2. Original Cost Rate Base, Capital Structure, and Fair Return.

(a) Original Cost Rate Base. NIPSCO agrees its weighted average cost of capital times its original cost rate base yields a fair return for purposes of this case. Based upon this Agreement, the Settling Parties agree NIPSCO should be authorized a fair rate of return of 7.14%, yielding an overall return for earnings test purposes of $651,868,680, based upon: (a) a Net Original Cost Rate Base of $9,129,813,441; and (b) NIPSCO's forecasted capital structure, including an authorized return on equity ("ROE") of 9.75%.

(b) Capital Structure and Fair Return. Based on the following capital structure, the 9.75% ROE, and the cost of debt/zero cost capital as filed, the overall weighted average cost of capital is computed as follows:

	Dollars	**Cost %**	**WACC %**
Common Equity	$7,718,129,223	9.75%	5.17%
Long-Term Debt	$5,468,979,284	5.20%	1.95%
Customer Deposits	$59,885,295	5.63%	0.02%
Deferred Income Taxes	$1,691,723,532	0.00%	0.00%

Post-Retirement Liability	$(7,491,885)	0.00%	0.00%
Prepaid Pension Asset	$(372,308,313)	0.00%	0.00%
Post-1970 ITC	$174,612	7.87%	0.00%
Totals	**$14,559,091,748**		**7.14%**

The Settling Parties agree that fair return under the Agreement will be calculated based upon the actual capital structure and rate base as described in the Implementation of Rates set forth in Paragraph B.10.

3. Depreciation and Amortization Expense.

(a) Depreciation Expense. The Settling Parties agree to a $12,270,000 reduction to NIPSCO's proposed depreciation expense. This amount is comprised of a $10,000,000 reduction as a result of reducing decommissioning costs and adjusting originally proposed service lives or net salvage components associated with certain depreciation accrual rates; and a $2,270,000 reduction as a result of the $100,000,000 reduction to NIPSCO's case-in-chief forecasted Transmission & Distribution Rate Base. The resulting depreciation accrual rates to which the Settling Parties agree are shown in Joint Exhibit B attached to this Agreement

(b) Amortization Expense. The Settling Parties agree to a $5,556,445 reduction to NIPSCO's proposed amortization expense achieved by modifying the amortization periods for TDSIC and Electric Rate Case Expense regulatory asset balances from two to four years. NIPSCO shall make a compliance filing at the

conclusion of all amortization periods as each concludes to remove the amortization from the revenue requirement, and rates will be adjusted accordingly.

4. Pro Forma Net Operating Income at Present Rates.

(a) Fuel Costs. The Settling Parties agree the base cost of fuel proposed in NIPSCO's case-in-chief will be reduced by $8,970,840.

(b) O&M Expenses. The Settling Parties agree to a $20,000,000 reduction to total O&M in this case. This reduction is a compromise to resolve numerous disputed issues in this Cause, including NIPSCO labor vacancies (generation and non-generation related), NiSource Corporate Service Company (NCSC) labor vacancies, vegetation management expense, and certain estimated costs incurred to execute NIPSCO's rate case.

5. Bill Assistance Program. The Settling Parties recommend approval of NIPSCO's request for approval of a bill assistance program (Rider 697 – Universal Service Program Rider) with the following changes:

(a) In recognition of concerns expressed by the OUCC, NIPSCO agrees to modify the bill assistance program from an opt-out program as proposed in NIPSCO's rebuttal to a voluntary, opt-in program; and

(b) In recognition of concerns expressed by the Settling Parties, NIPSCO will make an annual, below the line (*i.e.*, not to be recovered through rates) shareholder contribution of $1,500,000.

6. Customer Deposit. The Settling Parties agree to a reduction of NIPSCO's customer deposit from $50 to $0 for all NIPSCO gas and electric customers who receive bill assistance through LIHEAP.

7. Reconnection Charge. For NIPSCO's electric customers who are disconnected for non-payment of charges, NIPSCO agrees to waive its $90 electric reconnection charge (at the meter during normal business hours) set out in Section 15.1.1 of its General Rules and Regulations no later than with the implementation of Step 2 rates.

8. Disconnection Procedure. NIPSCO agrees to delay disconnection for non-payment of electric service if temperatures are below 20 degrees or above 90 degrees on the scheduled day of disconnection or are forecasted to be below 20 degrees or above 90 degrees the following two days.

9. Public Facing Electric Vehicle ("EV") Rate. NIPSCO commits to a stakeholder process within six (6) months of the date of the Final Order in this Cause with the intent of incorporating a public-facing EV rate to facilitate charging at customer-owned locations in NIPSCO's next electric base rate case.

10. Implementation of Rates. The Settling Parties agree the rate changes will be implemented on a services rendered basis after NIPSCO's new tariffs have been approved by the Commission's Energy Division. The rate increase agreed to herein should be implemented in multiple steps, as follows:

(a) Step 1 rates shall be implemented on a services rendered basis as soon as possible following the issuance of an Order in this Cause and approval of NIPSCO's new tariffs by the Commission's Energy Division and will be based on actual net plant certified to have been completed and placed in service no later than May 31, 2025, except for Fairbanks Solar Generating Facility ("Fairbanks") and Gibson Solar Generating Facility ("Gibson) as set forth herein. The Settling Parties agree that Step 1 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of May 31, 2025. Prior to implementation of Step 1 rates, NIPSCO will certify the net original cost rate base and current capital structure as of May 31, 2025, and calculate the Step 1 rates using those certified figures. For purposes of Step 1 rates, "certify" means NIPSCO states in a filing with the Commission in the above-captioned Cause the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of May 31, 2025. NIPSCO will serve all Parties to this proceeding with its certification. The Settling Parties, and other interested parties to this proceeding, will thereafter have sixty (60) days to verify or

state any objection to the net plant in service numbers from those which NIPSCO certifies. All Parties to this proceeding shall be permitted to conduct discovery to verify relevant construction costs and in service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual net plant in service as of May 31, 2025, and rates will be trued up, with carrying charges, retroactive to the date Step 1 rates were put into place.

(b) Step 2 rates shall be implemented on a services rendered basis as soon as possible after the end of the Forward Test Year and will be based on actual net plant certified to have been completed and placed in service no later than December 31, 2025. The Settling Parties agree that Step 2 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2025. Prior to implementation of Step 2 rates, NIPSCO will certify the net original cost rate base and current capital structure as of December 31, 2025 and calculate the Step 2 rates using those certified figures. For purposes of Step 2 rates, "certify" means NIPSCO states in a filing with the Commission in the above-referenced Cause the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2025. NIPSCO will serve all Parties to this proceeding with its certification. The Settling Parties, and other interested parties to this proceeding, will thereafter have sixty (60) days to verify or

state any objection to the net plant in service numbers from those which NIPSCO certifies. The Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 rates were put into place.

(c) In the event NIPSCO's Fairbanks and/or Gibson are not in service by the general rate base cutoff for Step 1 (May 31, 2025) but come into service on or before the general rate base cutoff for Step 2 (December 31, 2025), the Settling Parties agree to up to two additional steps to include these projects in rates earlier than Step 2 (end of the Forward Test Year). The compliance filing(s) for the additional step(s) will be based on the addition to rate base and associated depreciation expense for Fairbanks or Gibson (whichever the case may be) upon the filing of a certification that the plant is in service. The rates will use the capital structure used for Step 1 rates. NIPSCO shall file a certification in the above-captioned Cause that the asset is in service and serve a copy of such certification upon all Parties to this Cause. The rates will take effect on the same interim-subject-to-refund basis as Step 1 and Step 2 rates, with the same period for other parties to raise objections and for a hearing to potentially be conducted. To the extent Fairbanks and/or Gibson are not in service by May 31, 2025, but are in service by the time of the Step 1 compliance filing in this Cause, NIPSCO may include the plant in Step 1 rates calculated as provided in this paragraph, subject to potential objections,

true-up, and all other matters described in Section 10(a) above with respect to Step 1 rates.

11. Cost of Service and Rate Design. The provisions of the 831/531 Modification Settlement and Section B.7.(e) through (g) of the Settlement Agreement approved in Cause No. 45772 continue to apply.

(a) Mitigation. The Settling Parties acknowledge that, as presented in NIPSCO's case-in-chief and rebuttal, certain rate classes are being subsidized by several other rate classes. For this reason, the Settling Parties have agreed to mitigate a portion of the subsidy concerns raised by multiple parties in this Cause consistent with similar concerns recognized in and dealt with in Section B.7.b. of the Settlement Agreement approved in Cause No. 45772, which incorporates and recognizes the Commission's policy of gradualism. The settlement revenue requirement reduction (*i.e.*, the settled annual revenue requirement below NIPSCO's as-filed case in chief) in this Cause will be apportioned as follows: (1) set revenues for Rate 631 at cost of service based on 162.061 megawatts ("MW") of allocated Tier 1 demand; (2) no revenue change to Rate 642 and Rate 643; (3) credit $575,000 of the settlement revenue requirement decrease first to each Rate 623 and Rate 626; (4) allocate 25% of the remaining settlement revenue requirement decrease to the subsidizing classes in proportion to their excess revenues ("25% portion"); and (5) the remaining amount allocated on an across-the-board basis in

proportion to the case-in-chief proposed revenues (75% portion). Because Rate 631 is being brought to parity at 162.061 MW of allocated demand, it will not receive either a reduction relating to the 25% portion or a reduction related to the 75% portion, nor will Rate 642 and Rate 643 as there is no change in revenues for those rate classes. Rate 611 will participate in the across-the-board reduction (the 75% portion).[8] The provisions of this paragraph will be implemented in the cost of service study and rates included with NIPSCO's testimony supporting this Agreement.

(b) Production and Distribution Classification and Allocation in Future Cases. In light of issues raised by the OUCC, Industrial Group, U.S. Steel, and CAC, NIPSCO will study its production, transmission, and distribution classification and allocation before filing its next general electric rate case. This will include studying the classification and allocation of production, transmission (including subfunctionalization by voltage), and distribution customer, demand, and energy related costs both in base rates as well as in the FAC and RA trackers. If, based on that study, NIPSCO subsequently proposes new methods for the classification and allocation of production, transmission, and distribution costs in its next general rate case, it will file testimony explaining and substantiating each of those changes. If NIPSCO does not adopt any such changes, it will similarly file testimony providing the results of its analysis demonstrating why NIPSCO has concluded the current approach remains appropriate.

[8] As further provided below, Rate 611 will be NIPSCO's only residential rate, as the proposed Rate 615 will not be adopted under the terms of this Agreement.

All Settling Parties retain all rights in future proceedings to take any position and litigate these issues.

(c) Reductions in Tier 1 Load and Cost Allocations. The Settling Parties agree that a method for future reduction in Rate 631 Tier 1 allocated and contract demand provided for in the 831/531 Modification Settlement is accomplished through the approach recommended by Industrial Group Witness Dauphinais (Direct at 22-23), with the exclusion of costs associated with Sugar Creek Generating Station, as recommended by U.S. Steel Witness Schuepbach in cross-answering testimony (at 7). Using this approach, the allocated Rate 631 Tier 1 demand shall be 162.061 MW. Mr. Dauphinais' recommendation (Direct at 24-25) of proportional reductions to Rate 631 Tier 1 contract demand to progressively narrow the disparity between Rate 631 allocated demand and class contract demand in order to move the rate toward the actual cost of service should also be approved. The contract demand assumed for purposes of this Agreement shall be 153.692 MW. The Rate 631 charges (transmission, energy, and demand) will be based upon the 153.692 MW of contract demand assumed for purposes of this Agreement as reflected in Confidential Joint Exhibit C, which is expected to be consistent with executed Rate 631 contracts. Future reductions to Rate 631 Tier 1 cost allocations shall continue to follow the methodology set forth in Paragraph 7(f) of the Stipulation and Settlement Agreement approved by the

Commission in Cause No. 45772 employing the computational methodology utilized in this Agreement.

(d) Rate 626. The settlement revenue requirement decrease allocated to Rate 626 will be applied 50% to Rate 626's demand charge and 50% to its energy charge.

(e) Customer Charges. Customer charges proposed by NIPSCO in its case-in-chief shall be approved, except NIPSCO's monthly customer charge for Rate 611 shall remain at $14.00.

12. Data Center Sub-docket. Certain parties in this Cause have requested the creation of a sub-docket for purposes of developing a standard tariff offering and addressing other pertinent issues related to new large or mega load customers that may locate in NIPSCO's electric service territory. Since the filing of NIPSCO's case-in-chief and the OUCC's and intervenors' cases-in-chief, NIPSCO has made a filing related to its proposed overall strategy to serve large or mega load customers, in which NIPSCO acknowledged that it has not entered into any special contract or equivalent agreement for energy services for a large or mega load customer. NIPSCO's intention is that any large or mega load customer that may enter into a contract for electric service will commit to pay the direct, incremental costs associated with serving their load and some portion of the costs of NIPSCO's existing electric system. To the extent NIPSCO enters into such contract(s), NIPSCO commits to timely file a proposal with the Commission to

timely pass back to NIPSCO's current electric customers the revenues NIPSCO collects related to payment for recovery of some portion of the costs of NIPSCO's existing electric system paid by the large or mega load customer(s). This settlement provision in no way waives or otherwise limits any argument a party may make in pending Cause No. 46183 or related dockets surrounding large or mega load customers, except NIPSCO shall be precluded from requesting that any portion of the revenues identified above not be passed to NIPSCO's then current electric customers.

13. Multi-Family Rate. The Settling Parties agree NIPSCO's requested multi-family rate shall not be implemented. NIPSCO will collect additional data on residential customer housing types to further identify multi-family customers and further analyze cost differentials between single- and multi-family residential customers. NIPSCO may consider requesting a new multi-family rate for qualifying residential customers in its next rate case. Once additional analysis is complete, NIPSCO will meet with CAC, the OUCC, and any other interested stakeholders prior to filing its next base rate case to discuss a potential multi-family rate and will provide CAC, the OUCC, and any other interested stakeholders with the results of its analysis.

14. LaPorte County. LaPorte County is agreeing to not oppose this Agreement for the consideration and commitments contained in Addendum A, which NIPSCO agrees to support, but which other Settling Parties will not oppose.

15. RV Group. The RV Group is signing this Agreement to receive the benefits contained herein and for the consideration and commitments contained in Addendum B, which NIPSCO agrees to support, but which other Settling Parties will not oppose. With respect to the RV Group TDSIC provisions in Addendum B, the Settling Parties (other than NIPSCO) take no position on and do not endorse such provisions but will not oppose them.

16. Other Relief Requested by NIPSCO. The Settling Parties agree that all other matters for which NIPSCO requested relief in this Cause that are not addressed herein, but NIPSCO expressly supported by testimony, should be approved as NIPSCO proposed, or, if modified in NIPSCO's rebuttal, consistent with such modification, without waiving the right to challenge such resolution prospectively.

C. Procedural Aspects and Presentation of the Agreement

1. The Settling Parties acknowledge that a significant motivation to enter into this Agreement is the simplification and minimization of issues to be presented in the proceeding.

2. The Settling Parties agree to jointly present this Agreement to the Commission for approval in this proceeding and agree to assist and cooperate in the preparation and presentation of supplemental testimony as necessary to provide an appropriate factual basis for such approval. All evidence which has been prefiled by

the Settling Parties will be admitted into the record. All Settling Parties waive cross-examination on all witnesses of other Settling Parties but reserve the right to ask questions of any witness who may be cross-examined by a non- settling party.

3. The concurrence of the Settling Parties with the terms of this Agreement is expressly predicated upon the Commission's approval of the Agreement in its entirety without modification of a material condition deemed unacceptable to any Settling Party. If the Commission does not approve the Agreement in its entirety, the Agreement shall be null and void and deemed withdrawn upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that contains any unacceptable modifications. If the Agreement is withdrawn, the Settling Parties agree that the terms herein shall not be admissible in evidence or cited by any party in a subsequent proceeding. In the event the Agreement is withdrawn, the Settling Parties will request an Attorneys' Conference to be convened to establish a procedural schedule for the continued litigation of this proceeding.

4. The Settling Parties acknowledge that this Agreement addresses all issues in the proceeding, including the appropriate revenue requirement and allocation of costs, and includes compromises upon the part of each Settling Party. The Settling Parties agree that this Agreement and each term, condition, amount, methodology, and exclusion contained herein (a) reflects a fair, just, and reasonable resolution and compromise for the purpose of settlement; (b) has accounted for the overall level of risk

presented to NIPSCO by the Agreement; and (c) is agreed upon without prejudice to the ability of any party to propose a different term, condition, amount, methodology, or exclusion in any future proceeding. As set forth in the Order in *Re Petition of Richmond Power & Light*, Cause No. 40434, the Settling Parties agree and ask the Commission to incorporate as part of its Final Order that this Agreement, and any Final Order approving it, not be cited as precedent by any person or deemed an admission by any party in any other proceeding except as necessary to enforce its terms before the Commission or any court of competent jurisdiction on these particular issues. This Agreement is solely the result of compromise in the settlement process. Each of the Settling Parties has entered into this Agreement solely to avoid future disputes and litigation with attendant inconvenience and expense.

5. The Settling Parties stipulate that the evidence of record presented in this Cause constitutes substantial evidence sufficient to support this Agreement and provides an adequate evidentiary basis upon which the Commission can make any finding of fact and conclusion of law necessary for the approval of this Agreement as filed. The Settling Parties agree to the admission into the evidentiary record of this Agreement, along with testimony supporting it, without objection.

6. The undersigned represent and agree that they are fully authorized to execute this Agreement on behalf of their designated clients who will be bound thereby; and further represent and agree that each Settling Party has had the opportunity to

review all evidence in this proceeding, consult with attorneys and experts, and is otherwise fully advised of the terms.

7. The Settling Parties shall not appeal the agreed Final Order or any subsequent Commission order as to any portion of such order that is specifically implementing, without modification, the provisions of this Agreement, and the Settling Parties shall not support any appeal of any portion of the Final Order by any person not a party to this Agreement.

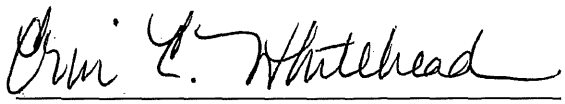
8. The provisions of this Agreement shall be enforceable by any Settling Party before the Commission or in any court of competent jurisdiction.

9. The terms set forth in this Agreement are the complete and final agreement among the Settling Parties. The communications and discussions during the negotiations and conferences which produced this Agreement have been conducted on the explicit understanding that they are or relate to offers of settlement and shall therefore be confidential and privileged communications.

ACCEPTED AND AGREED this 7th day of February, 2025.

[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC



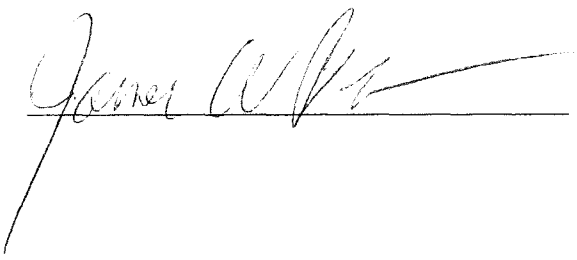
Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Indiana Office of Utility Consumer Counselor

William Fine
Utility Consumer Counselor
Indiana Office of Utility Consumer Counselor
115 West Washington Street, Suite 1500 South
Indianapolis, Indiana 46204

NIPSCO Industrial Group

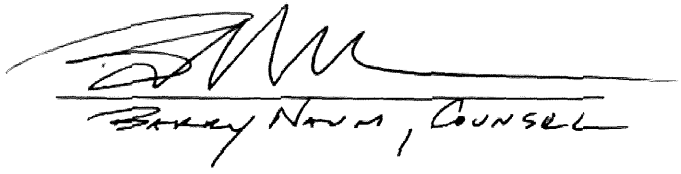
NLMK Indiana



United States Steel Corporation

Kristina Kern Wheeler, Counsel for USS

Walmart Inc.



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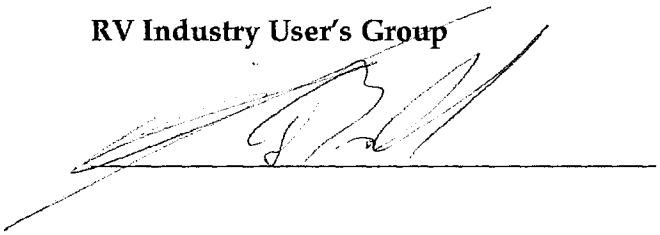
RV Industry User's Group



Northern Indiana Public Service Company LLC
Statement of Operating Income
Actual, Pro forma, and Proposed
For the Twelve Month Period Ending December 31, 2025

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments	Attachment 3-C Reference	Pro forma Results Based on Proposed Rates	Pro forma Adjustments to Include ITC/PTC & U17/18 Fuel Reduction	Attachment 3-C Reference	Total Pro forma Adjustments Increases (Decreases)	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H	I	J	K	L
1	**Operating Revenue**											
2	Revenue (Actual / Pro Forma)	$ 1,767,958,828		REV, Col A	$ 1,829,598,917	313,139,816	PF - 1 - S2-S	$ 2,142,738,733	(56,096,064)	PF - 5 - S2	257,043,752	$ 2,086,642,669
3	Pro forma Adjustments December 31, 2023		16,183,927	REV, Col B								
4	2024 Year-Over-Year Increase/(Decrease)		172,399,174	REV, Col D								
5	2025 Year-Over-Year Increase/(Decrease)		(16,191,462)	REV, Col F								
6	Ratemaking Adjustments December 31, 2025		(110,761,550)	REV, Col H								
7	Total Operating Revenue	$ 1,767,958,828	$ 61,630,089		$ 1,829,598,917	$ 313,139,816		$ 2,142,738,733	$ (56,096,064)		$ 257,043,752	$ 2,086,642,669
8	**Fuel & Purchased Power**											
9	Fuel and Purchase Power Cost (Actual / Pro Forma)	$ 435,087,415		FPP, Col A	$ 320,663,203	-		$ 320,663,203			(55,755,482)	$ 264,907,721
10	Pro forma Adjustments December 31, 2023		5,184,043	FPP, Col B								
11	2024 Year-Over-Year Increase/(Decrease)		(43,532,296)	FPP, Col D								
12	2025 Year-Over-Year Increase/(Decrease)		(67,201,186)	FPP, Col F								
13	Ratemaking Adjustments December 31, 2025		(8,874,773)	FPP-S, Col H					(55,755,482)	PF - 6 - S2, FPP, Col J		
14	Total Fuel and Purchased Power Costs	$ 435,087,415	$ (114,424,212)		$ 320,663,203	$ -		$ 320,663,203	$ (55,755,482)		$ (55,755,482)	$ 264,907,721
15	Gross Margin	$ 1,332,871,413	$ 176,054,301		$ 1,508,935,713	$ 313,139,816		$ 1,822,075,530	$ (340,582)		$ 312,799,234	$ 1,821,734,948
16	**Operations and Maintenance Expenses**											
17	Operations and Maintenance Expenses (Actual / Pro Forma)	$ 522,342,734		O&M, Col A	$ 447,401,861	1,431,487	PF - 2 - S2-S	$ 448,833,349	(256,436)	PF - 7 - 52	1,175,050	$ 448,576,911
18	Pro forma Adjustments December 31, 2023		(25,587,605)	O&M, Col B								
19	2024 Year-Over-Year Increase/(Decrease)		21,878,245	O&M, Col D								
20	2025 Year-Over-Year Increase/(Decrease)		12,295,875	O&M, Col F								
21	Ratemaking Adjustments December 31, 2025		(63,527,388)	O&M-S, Col H								
22	Total Operations and Maintenance Expense	$ 522,342,734	$ (74,940,873)		$ 447,401,861	$ 1,431,487		$ 448,833,349	$ (256,436)		$ 1,175,050	$ 448,576,911
23	**Depreciation Expense**											
24	Depreciation Expense (Actual / Pro Forma)	$ 271,619,214		DEPR, Col A	$ 376,764,290			$ 376,764,290			-	$ 376,764,290
25	Pro forma Adjustments December 31, 2023		(2,752,431)	DEPR, Col B								
26	2024 Year-Over-Year Increase/(Decrease)		48,483,292	DEPR, Col D								
27	2025 Year-Over-Year Increase/(Decrease)		66,704,866	DEPR, Col F								
28	Ratemaking Adjustments December 31, 2025		(7,290,652)	DEPR-S, Col H								
29	Total Depreciation Expense	$ 271,619,214	$ 105,145,076		$ 376,764,290	$ -		$ 376,764,290	$ -		$ -	$ 376,764,290

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments	Attachment 3-C Reference	Pro forma Results Based on Proposed Rates	Pro forma Adjustments to Include ITC/PTC & U17/18 Fuel Reduction	Attachment 3-C Reference	Total Pro forma Adjustments Increases (Decreases)	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H	I	J	K	L
30	**Amortization Expense**											
31	Amortization Expense (Actual / Pro Forma)	$ 93,159,655		AMTZ, Col A	$ 177,418,026			$ 177,418,026			-	$ 177,418,026
32	Pro forma Adjustments December 31, 2023		15,642,588	AMTZ, Col B								
33	2024 Year-Over-Year Increase/(Decrease)		23,076,154	AMTZ, Col D								
34	2025 Year-Over-Year Increase/(Decrease)		2,818,657	AMTZ, Col F								
35	Ratemaking Adjustments December 31, 2025		42,718,971	AMTZ-S, Col H								
36	Total Amortization Expense	$ 93,159,655	$ 84,258,371		$ 177,418,026	$ -		$ 177,418,026	$ -		$ -	$ 177,418,026
37	**Taxes**											
38	**Taxes Other than Income**											
39	Taxes Other than Income (Actual / Pro Forma)	$ 35,013,168		OTX, Col A	$ 43,310,222			$ 43,310,222			-	$ 43,310,222
40	Pro forma Adjustments December 31, 2023		(195,174)	OTX, Col B								
41	2024 Year-Over-Year Increase/(Decrease)		4,404,074	OTX, Col D								
42	2025 Year-Over-Year Increase/(Decrease)		5,732,803	OTX, Col F								
43	Ratemaking Adjustments December 31, 2025		(1,644,649)	OTX, Col H		469,710	PF - 3 - S2-S	$ 469,710	(84,144)	PF - 8 - S2	385,566	$ 385,566
44	Total Taxes Other Than Income	$ 35,013,168	$ 8,297,054		$ 43,310,222	$ 469,710		$ 43,779,932	$ (84,144)		$ 385,566	$ 43,695,787
45	**Operating Income Before Income Taxes**	$ 410,746,641	$ 53,294,673		$ 464,041,314	$ 311,238,619		$ 775,279,933	$ -		$ 311,238,619	$ 775,279,933
46	**Income Taxes**											
47	Federal and State Taxes (Actual / Pro Forma)	$ 47,253,086	(1,249,990)	Attachment 3-C-S, ITX 1-S	$ 46,003,096	77,408,157	PF - 4 - S2-S	$ 123,411,253	-	PF - 9 - S2	77,408,157	$ 123,411,253
48	Total Taxes	$ 82,266,254	$ 7,047,064		$ 89,313,318	$ 77,877,867		$ 167,191,185	$ (84,144)		$ 77,793,723	$ 167,107,041
49	**Total Operating Expenses including Income Taxes**	$ 969,387,857	$ 121,509,536		$ 1,090,897,495	$ 79,309,354		$ 1,170,206,849	$ (340,582)		$ 78,968,772	$ 1,169,866,268
50	**Required Net Operating Income**	$ 383,493,556	$ 54,544,662		$ 418,038,217.55000	$ 233,830,462		$ 651,868,680	$ -		$ 233,830,462	$ 651,868,680

Northern Indiana Public Service Company LLC
Calculation of Proposed Revenue Increase
Based on Pro forma Operating Results
Original Cost Rate Base Estimated at December 31, 2025

Line No.	Description				Revenue Deficiency
1	Net Original Cost Rate Base				$ 9,129,813,441
2	Rate of Return				7.14%
3	Net Operating Income				651,868,680
4	Pro forma Net Operating Income				418,038,218
5	Increase in Net Operating Income (NOI Shortfall)				233,830,462
6	Effective Incremental Revenue NOI Conversion Factor				74.673%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)				$ 313,139,816
8	One	1.000000			
9	Less: Public Utility Fee	0.001500			
10	Less: Bad Debt	0.004571			
11	State Taxable Income		0.993929		
12	Taxable Adjusted Gross Income Tax	0.993929			
13	Adjusted Gross Income Tax Rate	0.049000			
14	Adjusted Gross Income Tax		0.048703		
15	Line 11 less line 14			0.945226	
16	One		1.000000		
17	Less: Federal Income Tax Rate		0.210000		
18	One Less Federal Income Tax Rate			0.790000	
19	Effective Incremental Revenue / NOI Conversion Factor				74.673%

Northern Indiana Public Service Company LLC
Summary of Rate Base
As Of December 31, 2025

Line No.	Description	As Of December 31, 2025	Attachment 3-B-S2-S Reference
	Electric Rate Base		
1	Utility Plant	$ 10,216,836,696	RB, Col I
2	Non Jurisdictional Plant	-	RB, Col I
3	Common Allocated	419,723,256	RB, Col I
	Total Electric Utility Plant	10,636,559,953	RB, Col I
4	Utility Plant Accumulated Depreciation and Amortization	(2,977,780,579)	RB, Col I
5	Non Jurisdictional Plant Accumulated Depreciation and Amortization	-	RB, Col I
6	Common Allocated Accumulated Depreciation and Amortization	(262,627,721)	RB, Col I
	Total Electric Accumulated Depreciation and Amortization	(3,240,408,299)	RB, Col I
	Net Electric Utility Plant	$ 7,396,151,653	RB, Col I
7	Schahfer Units 14, 15, 17 and 18 Retirement Net Plant	661,125,225	RB, Col I
8	WAM Regulatory Asset	28,237,008	RB, Col I
9	Renewable Energy Joint Venture Investments	772,866,616	RB, Col I
10	Cause Nos. 45772 & 45159 Remainder	24,524,961	RB, Col I
11	Electric TDSIC Cause Nos. 44733 and 45557	18,679,396	RB, Col I
12	Wholly Owned Solar Farms - Regulatory Asset	99,839,760	RB, Col I
13	Materials & Supplies	112,720,299	RB, Col I
14	Production Fuel	15,668,523	RB, Col I
	Total Electric Rate Base	**$ 9,129,813,441**	RB, Col I

Northern Indiana Public Service Company LLC
Capital Structure
As Of December 31, 2025

Line No.	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
1	Common Equity	$ 7,718,129,223	53.01%	9.75%	5.17%
2	Long-Term Debt	5,468,979,284	37.56%	5.20%	1.95%
3	Customer Deposits	59,885,295	0.41%	5.63%	0.02%
4	Deferred Income Taxes	1,691,723,532	11.62%	0.00%	0.00%
5	Post-Retirement Liability	(7,491,885)	-0.05%	0.00%	0.00%
6	Prepaid Pension Asset	(372,308,313)	-2.56%	0.00%	0.00%
7	Post-1970 ITC	174,612	0.00%	7.87%	0.00%
8	Totals	**$ 14,559,091,748**	**100.00%**		**7.14%**

Cost of Investor Supplied Capital

	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
9	Common Equity	$ 7,718,129,223	58.53%	9.75%	5.71%
10	Long-Term Debt	5,468,979,284	41.47%	5.20%	2.16%
11	**Totals**	**$ 13,187,108,507**	**100.00%**		**7.87%**

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2025

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
STEAM PRODUCTION PLANT									
311.00 STRUCTURES AND IMPROVEMENTS									
MICHIGAN CITY GENERATING STATION	12-2028	110-R2.5 *	(62)	46,027,141.95	19,214,893	55,349,077	6,511,656 **	14.15	8.5
MICHIGAN CITY - UNIT 12	12-2028	110-R2.5 *	(62)	105,391,567.33	51,508,881	119,225,458	14,026,524 **	13.31	8.5
TOTAL MICHIGAN CITY				151,418,709.28	70,723,774	174,574,535	20,538,180	13.56	8.5
SUGAR CREEK	06-2068	110-R2.5 *	(28)	8,084,108.45	4,094,685	6,252,974	152,043	1.88	41.1
TOTAL ACCOUNT 311				159,502,817.73	74,818,459	180,827,509	20,690,223	12.97	
BOILER PLANT EQUIPMENT									
312.10 BOILER PLANT EQUIPMENT									
MICHIGAN CITY GENERATING STATION	12-2028	55-R1 *	(62)	90,788,707.47	60,688,863	86,388,843	10,163,393 **	11.19	8.5
MICHIGAN CITY - UNIT 12	12-2028	55-R1 *	(62)	261,925,849.67	166,272,474	258,047,402	30,358,518 **	11.59	8.5
TOTAL MICHIGAN CITY				352,714,557.14	226,961,337	344,436,245	40,521,911	11.49	8.5
SUGAR CREEK	06-2068	55-R1 *	(28)	96,801,493.64	58,392,780	65,513,132	1,914,475	1.98	34.2
TOTAL ACCOUNT 312.1				449,516,050.78	285,354,117	409,949,377	42,436,386	9.44	
312.20 BOILER PLANT - MOBILE FUEL HANDLING AND STORAGE									
MICHIGAN CITY GENERATING STATION	12-2028	55-R1 *	(62)	8,502,659.44	8,356,263	5,418,045	637,417 **	7.50	8.5
MICHIGAN CITY - UNIT 12	12-2028	55-R1 *	(62)	796,688.99	826,154	464,482	54,645 **	6.86	8.5
TOTAL ACCOUNT 312.2				9,299,348.43	9,182,417	5,882,527	692,062	7.44	
312.30 BOILER PLANT - UNIT TRAIN COAL CARS									
MICHIGAN CITY GENERATING STATION		25-R2.5	0	2,841,743.85	2,753,480	88,264	10,384 **	0.37	8.5
312.40 BOILER PLANT - SO2 PLANT EQUIPMENT									
MICHIGAN CITY - UNIT 12	12-2028	55-R1 *	(62)	230,108,218.67	103,181,315	269,593,999	31,716,941 **	13.78	8.5
312.50 BOILER PLANT - COAL PILE BASE									
MICHIGAN CITY GENERATING STATION	12-2028	55-R1 *	(62)	717,113.23	1,197,579	(35,856)	(4,218) **	(0.59)	8.5
TOTAL ACCOUNT 312				692,482,474.96	401,668,908	685,478,311	74,851,555	10.81	
314.00 TURBOGENERATOR UNITS									
MICHIGAN CITY GENERATING STATION	12-2028	60-R2 *	(62)	4,843,911.56	710,782	7,136,355	839,571 **	17.33	8.5
MICHIGAN CITY - UNIT 12	12-2028	60-R2 *	(62)	97,485,934.88	45,078,446	112,848,769	13,276,326 **	13.62	8.5
TOTAL MICHIGAN CITY				102,329,846.44	45,789,228	119,985,124	14,115,897	13.79	8.5
SUGAR CREEK	06-2068	60-R2 *	(28)	57,816,549.33	27,669,122	46,336,061	1,291,945	2.23	35.9
TOTAL ACCOUNT 314				160,146,395.77	73,458,350	166,321,185	15,407,842	9.62	

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2025

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
315.00 ACCESSORY ELECTRIC EQUIPMENT									
MICHIGAN CITY GENERATING STATION	12-2028	70-R2 *	(62)	23,807,800.73	25,656,902	12,911,735	1,519,028 **	6.38	8.5
MICHIGAN CITY - UNIT 12	12-2028	70-R2 *	(62)	35,227,102.15	39,953,156	17,114,749	2,013,500 **	5.72	8.5
TOTAL MICHIGAN CITY				59,034,902.88	65,610,058	30,026,484	3,532,528	5.98	8.5
SUGAR CREEK	06-2068	70-R2 *	(28)	4,897,315.43	2,894,694	3,373,870	89,263	1.82	37.8
TOTAL ACCOUNT 315				63,932,218.31	68,504,752	33,400,354	3,621,791	5.67	
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
MICHIGAN CITY GENERATING STATION	12-2028	70-R1.5 *	(62)	3,931,264.86	493,793	5,874,856	691,160 **	17.58	8.5
MICHIGAN CITY - UNIT 12	12-2028	70-R1.5 *	(62)	5,441,982.85	631,322	8,184,690	962,905 **	17.69	8.5
TOTAL MICHIGAN CITY				9,373,247.71	1,125,115	14,059,546	1,654,065	17.65	8.5
SUGAR CREEK	06-2068	70-R1.5 *	(28)	3,563,623.43	1,126,831	3,434,607	91,471	2.57	37.5
TOTAL ACCOUNT 316				12,936,871.14	2,251,946	17,494,153	1,745,536	13.49	
TOTAL STEAM PRODUCTION PLANT				**1,089,000,777.91**	**620,702,415**	**1,083,521,512**	**116,316,947**	**10.68**	
HYDROELECTRIC PRODUCTION PLANT									
331.00 STRUCTURES AND IMPROVEMENTS									
NORWAY GENERATING STATION	11-2037	70-S1 *	(12)	4,615,792.78	1,890,273	3,279,415	278,401	6.03	11.8
OAKDALE GENERATING STATION	11-2037	70-S1 *	(8)	7,173,147.86	3,202,088	4,544,912	386,078	5.38	11.8
TOTAL ACCOUNT 331				11,788,940.64	5,092,361	7,824,327	664,479	5.64	
332.00 RESERVOIRS, DAMS AND WATERWAYS									
NORWAY GENERATING STATION	11-2037	85-R2.5 *	(12)	33,719,831.63	8,970,126	28,796,085	2,438,359	7.23	11.8
OAKDALE GENERATING STATION	11-2037	85-R2.5 *	(8)	37,145,730.66	9,118,796	30,998,593	2,622,088	7.06	11.8
TOTAL ACCOUNT 332				70,865,562.29	18,088,922	59,794,678	5,060,447	7.14	
333.00 WATER WHEELS, TURBINES AND GENERATORS									
NORWAY GENERATING STATION	11-2037	75-R2 *	(12)	7,950,788.80	3,174,832	5,730,051	518,515	6.52	11.1
OAKDALE GENERATING STATION	11-2037	75-R2 *	(8)	6,429,578.26	2,452,118	4,491,827	386,919	6.02	11.6
TOTAL ACCOUNT 333				14,380,367.06	5,626,950	10,221,878	905,434	6.30	
334.00 ACCESSORY ELECTRIC EQUIPMENT									
NORWAY GENERATING STATION	11-2037	55-L1.5 *	(12)	1,678,599.17	1,091,445	788,586	72,478	4.32	10.9
OAKDALE GENERATING STATION	11-2037	55-L1.5 *	(8)	830,241.56	326,461	570,200	49,769	5.99	11.5
TOTAL ACCOUNT 334				2,508,840.73	1,417,906	1,358,786	122,247	4.87	

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2025

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
335.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
NORWAY GENERATING STATION	11-2037	60-S0.5 *	(12)	1,022,677.29	360,067	785,332	67,846	6.63	11.6
OAKDALE GENERATING STATION	11-2037	60-S0.5 *	(8)	270,873.17	100,425	192,118	16,689	6.16	11.5
TOTAL ACCOUNT 335				1,293,550.46	460,492	977,450	84,535	6.54	
TOTAL HYDROELECTRIC PRODUCTION PLANT				**100,837,261.18**	**30,686,631**	**80,177,119**	**6,837,142**	**6.78**	
OTHER PRODUCTION PLANT									
341.00 STRUCTURES AND IMPROVEMENTS									
R M SCHAHFER - UNITS 16A AND 16B	12-2026	55-R3 *	(3)	2,484,301.00	1,872,564	686,266	686,264	27.62	1.0
R M SCHAHFER - UNIT 16A	12-2026	55-R3 *	(3)	212,249.57	211,909	6,708	6,708	3.16	1.0
TOTAL R M SCHAHFER				2,696,550.57	2,084,473	692,974	692,972	25.70	1.0
SUGAR CREEK	06-2068	55-R3 *	(17)	13,149,657.86	6,912,218	8,472,882	239,019	1.82	35.4
TOTAL ACCOUNT 341				15,846,208.43	8,996,691	9,165,856	931,991	5.88	
341.10 STRUCTURES AND IMPROVEMENTS - SOLAR		35-S2.5 *	0	49,455.17	3,484	45,971	1,411	2.85	32.6
341.20 STRUCTURES AND IMPROVEMENTS - UTILITY-SCALE SOLAR									
CAVALRY	06-2054	35-R4 *	(16)	54,184,033.32	3,467,681	59,385,798	2,176,899	4.02	27.3
DUNNS BRIDGE II	06-2055	35-R4 *	(9)	105,743,471.58	2,116,878	113,143,506	4,000,831	3.78	28.3
FAIRBANKS	06-2055	35-R4 *	(14)	64,977,969.18	1,361,577	72,713,308	2,571,192	3.96	28.3
GIBSON	06-2055	35-R4 *	(17)	53,506,855.66	1,151,239	61,451,782	2,172,977	4.06	28.3
TOTAL ACCOUNT 341.2				278,412,329.74	8,097,375	306,694,394	10,921,899	3.92	
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES									
R M SCHAHFER - UNITS 16A AND 16B	12-2026	55-S2 *	(3)	9,106,086.70	6,611,384	2,767,885	2,767,887	30.40	1.0
SUGAR CREEK	06-2048	55-S2 *	(17)	3,199,461.54	2,257,626	1,485,744	70,570	2.21	21.1
TOTAL ACCOUNT 342				12,305,548.24	8,869,010	4,253,629	2,838,457	23.07	
343.00 PRIME MOVERS									
R M SCHAHFER - UNITS 16A AND 16B	12-2026	50-R1 *	(3)	3,850,660.76	1,184,933	2,781,248	2,781,249	72.23	1.0
R M SCHAHFER - UNIT 16A	12-2026	50-R1 *	(3)	15,109,175.53	14,173,710	1,388,741	1,388,740	9.19	1.0
R M SCHAHFER - UNIT 16B	12-2026	50-R1 *	(3)	23,015,175.73	22,726,733	978,898	978,898	4.25	1.0
TOTAL R M SCHAHFER				41,975,012.02	38,085,376	5,148,887	5,148,887	12.27	1.0
SUGAR CREEK	06-2048	50-R1 *	(17)	118,449,540.98	41,169,623	97,416,340	4,735,768	4.00	20.6
TOTAL ACCOUNT 343				160,424,553.00	79,254,999	102,565,227	9,884,655	6.16	

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2025

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
344.00 GENERATORS										
R M SCHAHFER - UNIT 16A	12-2026	55-R3	*	(3)	5,927,994.17	5,220,374	885,460	885,459	14.94	1.0
R M SCHAHFER - UNIT 16B	12-2026	55-R3	*	(3)	2,723,343.82	2,672,305	132,739	132,740	4.87	1.0
TOTAL R M SCHAHFER					8,651,337.99	7,892,679	1,018,199	1,018,199	11.77	1.0
SUGAR CREEK	06-2048	55-R3	*	(17)	40,450,118.74	25,423,352	21,903,287	1,023,195	2.53	21.4
TOTAL ACCOUNT 344					49,101,456.73	33,316,031	22,921,486	2,041,394	4.16	
344.10 GENERATORS - SOLAR		25-S2.5		0	991,495.17	201,025	790,470	40,046	4.04	19.7
344.20 GENERATORS - UTILITY-SCALE SOLAR										
CAVALRY	06-2054	30-S1.5	*	(16)	277,438,546.57	17,755,358	304,073,356	12,570,209	4.53	24.2
DUNNS BRIDGE II	06-2055	30-S1.5	*	(9)	541,438,377.01	10,839,143	579,328,688	22,998,360	4.25	25.2
FAIRBANKS	06-2055	30-S1.5	*	(14)	332,706,744.45	6,971,750	372,313,939	14,780,228	4.44	25.2
GIBSON	06-2055	30-S1.5	*	(17)	273,971,193.27	5,894,743	314,651,553	12,491,130	4.56	25.2
TOTAL ACCOUNT 344.2					1,425,554,861.30	41,460,994	1,570,367,536	62,839,927	4.41	
345.00 ACCESSORY ELECTRIC EQUIPMENT										
R M SCHAHFER - UNITS 16A AND 16B	12-2026	50-S1	*	(3)	17,562,929.31	9,291,000	8,798,817	8,798,818	50.10	1.0
R M SCHAHFER - UNIT 16A	12-2026	50-S1	*	(3)	1,164,784.62	1,139,694	60,034	60,034	5.15	1.0
R M SCHAHFER - UNIT 16B	12-2026	50-S1	*	(3)	966,720.95	954,635	41,088	41,088	4.25	1.0
TOTAL R M SCHAHFER					19,694,434.88	11,385,329	8,899,939	8,899,940	45.19	1.0
SUGAR CREEK	06-2048	50-S1	*	(17)	34,529,128.11	22,844,101	17,554,979	882,580	2.56	19.9
TOTAL ACCOUNT 345					54,223,562.99	34,229,430	26,454,918	9,782,520	18.04	
345.10 ACCESSORY ELECTRIC EQUIPMENT - SOLAR		25-S2.5		0	247,873.83	50,631	197,243	9,992	4.03	19.7
345.20 ACCESSORY ELECTRIC EQUIPMENT - UTILITY-SCALE SOLAR										
CAVALRY	06-2054	40-R1.5	*	(16)	39,110,279.69	2,502,423	42,865,501	1,684,303	4.31	25.4
DUNNS BRIDGE II	06-2055	40-R1.5	*	(9)	76,326,114.82	1,528,229	81,667,236	3,101,680	4.06	26.3
FAIRBANKS	06-2055	40-R1.5	*	(14)	46,901,391.29	982,959	52,484,627	1,993,339	4.25	26.3
GIBSON	06-2055	40-R1.5	*	(17)	38,621,489.80	831,111	44,356,032	1,684,620	4.36	26.3
TOTAL ACCOUNT 345.2					200,959,275.60	5,844,722	221,373,396	8,463,942	4.21	

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2025

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
R M SCHAHFER - UNITS 16A AND 16B	12-2026	55-R2 *	(3)	401,558.85	243,846	169,760	169,761	42.28	1.0
R M SCHAHFER - UNIT 16A	12-2026	55-R2 *	(3)	56,008.00	53,824	3,864	3,864	6.90	1.0
TOTAL R M SCHAHFER				457,566.85	297,670	173,624	173,625	37.95	1.0
SUGAR CREEK	06-2048	55-R2 *	(17)	5,637,396.32	3,119,781	3,475,973	165,185	2.93	21.0
TOTAL ACCOUNT 346				6,094,963.17	3,417,451	3,649,597	338,810	5.56	
TOTAL OTHER PRODUCTION PLANT				**2,204,211,583.37**	**223,741,843**	**2,268,479,723**	**108,095,044**	**4.90**	
TRANSMISSION PLANT									
350.20 LAND RIGHTS		80-R4	0	15,667,095.38	11,598,910	4,068,185	52,355	0.33	77.7
352.00 STRUCTURES AND IMPROVEMENTS		70-R1.5	(20)	120,006,206.97	27,822,792	116,184,656	1,905,289	1.59	61.0
353.00 STATION EQUIPMENT		51-S0	(10)	1,209,443,672.94	274,868,958	1,055,519,082	24,320,538	2.01	43.4
354.00 TOWERS AND FIXTURES		75-R3	(30)	234,065,559.12	92,070,828	212,214,399	3,384,642	1.45	62.7
355.00 POLES AND FIXTURES		62-R1	(40)	441,931,660.13	111,011,176	507,693,148	9,090,957	2.06	55.8
356.00 OVERHEAD CONDUCTORS AND DEVICES		70-R2	(40)	316,129,902.23	121,826,202	320,755,661	5,374,212	1.70	59.7
357.00 UNDERGROUND CONDUIT		70-S4	(5)	904,994.78	701,583	248,662	4,599	0.51	54.1
358.00 UNDERGROUND CONDUCTORS AND DEVICES		50-R1.5	(5)	4,441,926.88	1,276,270	3,387,753	80,942	1.82	41.9
359.00 ROADS AND TRAILS		65-R4	0	31,088.94	15,016	16,073	609	1.96	26.4
TOTAL TRANSMISSION PLANT				**2,342,622,107.37**	**641,191,735**	**2,220,087,619**	**44,214,143**	**1.89**	
DISTRIBUTION PLANT									
360.20 LAND RIGHTS		80-R4	0	1,611,388.87	381,082	1,230,307	18,800	1.17	65.4
361.00 STRUCTURES AND IMPROVEMENTS		70-R1.5	(20)	20,834,098.08	9,549,803	15,451,115	276,487	1.33	55.9
362.00 STATION EQUIPMENT		52-S0	(10)	695,297,773.42	169,278,666	595,548,885	13,497,363	1.94	44.1
POLES, TOWERS AND FIXTURES									
364.10 CUSTOMER TRANSFORMER STATION		49-S0	(55)	61,383,975.08	35,822,062	59,323,099	1,491,955	2.43	39.8
364.20 POLES, TOWERS, AND FIXTURES		48-R1	(55)	809,432,020.90	262,404,188	992,215,444	24,161,648	2.99	41.1
TOTAL ACCOUNT 364				870,815,995.98	298,226,250	1,051,538,543	25,653,603	2.95	
365.00 OVERHEAD CONDUCTORS AND DEVICES		65-R1	(65)	503,615,755.75	225,253,840	605,712,157	10,433,512	2.07	58.1
366.00 UNDERGROUND CONDUIT		70-S2.5	(5)	5,754,045.02	2,196,817	3,844,930	77,434	1.35	49.7
367.00 UNDERGROUND CONDUCTORS AND DEVICES		53-R2.5	(35)	719,335,598.55	213,843,036	757,260,022	17,533,397	2.44	43.2
368.00 LINE TRANSFORMERS		47-S0	(10)	438,272,677.07	156,425,125	325,674,820	6,781,818	2.00	37.1
SERVICES									
369.10 OVERHEAD SERVICES		48-R1	(50)	58,862,877.78	42,319,943	45,974,374	1,157,585	1.97	39.7
369.20 UNDERGROUND SERVICES		75-R3	(50)	329,574,657.54	155,332,144	339,029,842	5,315,742	1.61	63.8
TOTAL ACCOUNT 369				388,437,535.32	197,652,087	385,004,216	6,473,327	1.67	

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2025

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT		TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)=(8)/(5)	(10)=(7)/(8)
METERS										
370.10 CUSTOMER METERING STATIONS		50-R2	(5)	24,831,212.44	10,772,610	15,300,163	390,624		1.57	39.2
370.20 METERS		25-L0	(5)	129,340,994.65	28,225,729	107,582,315	5,066,122		3.92	21.2
TOTAL ACCOUNT 370				154,172,207.09	38,998,339	122,882,478	5,456,746		3.54	
371.00 INSTALLATIONS ON CUSTOMER PREMISES		20-O1	(30)	13,170,731.71	7,189,523	9,932,428	604,110		4.59	16.4
373.00 STREET LIGHTING AND SIGNAL SYSTEMS		30-L0	(40)	76,079,721.04	23,336,866	83,174,743	3,623,625		4.76	23.0
TOTAL DISTRIBUTION PLANT				**3,887,397,527.90**	**1,342,331,434**	**3,957,254,644**	**92,430,222**		**2.38**	
GENERAL PLANT										
390.00 STRUCTURES AND IMPROVEMENTS		60-R1.5	(10)	80,207,587.38	8,245,613	79,982,733	1,436,514		1.79	55.7
391.10 OFFICE FURNITURE AND EQUIPMENT		20-SQ	0	4,503,477.64	2,826,155	1,677,323	225,067		5.00	7.5
391.20 COMPUTERS AND PERIPHERAL EQUIPMENT		7-SQ	0	10,225,401.21	7,827,834	2,397,567	1,461,186		14.29	1.6
393.00 STORES EQUIPMENT		30-SQ	0	840,983.94	461,876	379,108	28,043		3.33	13.5
394.00 TOOLS, SHOP AND GARAGE EQUIPMENT		25-SQ	0	31,219,333.07	11,811,607	19,407,726	1,249,729		4.00	15.5
395.00 LABORATORY EQUIPMENT		20-SQ	0	5,386,440.92	3,348,174	2,038,267	269,165		5.00	7.6
397.00 COMMUNICATION EQUIPMENT		15-SQ	0	96,126,113.82	26,077,512	70,048,602	6,411,145		6.67	10.9
398.00 MISCELLANEOUS EQUIPMENT		20-SQ	0	5,148,328.91	1,999,319	3,149,010	257,323		5.00	12.2
TOTAL DEPRECIABLE GENERAL PLANT				**233,657,666.89**	**62,598,090**	**179,080,336**	**11,338,172**		**4.85**	
RESERVE ADJUSTMENT FOR AMORTIZATION										
391.10 OFFICE FURNITURE AND EQUIPMENT					125,698		(41,900)	***		3.0
391.20 COMPUTERS AND PERIPHERAL EQUIPMENT					5,847,536		(1,949,179)	***		3.0
393.00 STORES EQUIPMENT					32,579		(10,860)	***		3.0
394.00 TOOLS, SHOP AND GARAGE EQUIPMENT					66,081		(22,027)	***		3.0
395.00 LABORATORY EQUIPMENT					612,538		(204,179)	***		3.0
397.00 COMMUNICATION EQUIPMENT					(2,963,573)		987,857	***		3.0
398.00 MISCELLANEOUS EQUIPMENT					(51,772)		17,258	***		3.0
TOTAL RESERVE ADJUSTMENT FOR AMORTIZATION					**3,669,087**		**(1,223,030)**			
TOTAL DEPRECIABLE ELECTRIC PLANT				**9,857,726,924.62**	**2,924,921,235**	**9,788,600,953**	**378,008,640**		**3.83**	
NONDEPRECIABLE										
302.00 FRANCHISES AND CONSENTS				1,389.41						
303.00 MISCELLANEOUS INTANGIBLE PLANT				243,035,839.45	73,337,609					
310.00 LAND AND LAND RIGHTS				5,192,264.65	(4,007)					
311.00 STRUCTURES AND IMPROVEMENTS										
D H MITCHELL GENERATING STATION				0.00	4,481,692					
312.10 BOILER PLANT EQUIPMENT										
D H MITCHELL GENERATING STATION				0.00	2,821,855					

NORTHERN INDIANA PUBLIC SERVICE COMPANY

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ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
312.40 BOILER PLANT - SO2 PLANT EQUIPMENT									
D H MITCHELL GENERATING STATION				0.00	6,054				
312.50 BOILER PLANT - COAL PILE BASE									
D H MITCHELL GENERATING STATION				0.00	69,620				
314.00 TURBO-GENERATOR UNITS									
D H MITCHELL GENERATING STATION				0.00	3,298,615				
315.00 ACCESSORY ELECTRIC EQUIPMENT									
D H MITCHELL GENERATING STATION				401.20	(2,570,344)				
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
D H MITCHELL GENERATING STATION				0.00	(1,224,757)				
330.00 LAND AND LAND RIGHTS				24,250.62	(98)				
340.10 LAND				18,332,943.61	(14)				
340.20 LAND RIGHTS				76,947,694.40	(4,389)				
350.10 LAND				24,761,238.91	(397,571)				
360.10 LAND				10,426,228.44	(156,718)				
389.10 LAND				16,851.32					
389.20 LAND RIGHTS				101,627.34					
390.20 LEASED PROPERTY				212,673.04	211,320				
ACCOUNTS NOT STUDIED									
TRANSPORTATION EQUIPMENT									
392.10 TRANSPORTATION EQUIPMENT - AUTOS				0.00	(1,030,784)				
392.20 TRANSPORTATION EQUIPMENT - TRAILERS				1,918,863.64	1,148,444				
392.30 TRANSPORTATION EQUIPMENT - TRUCKS < 13,000				367,964.14	(152,667)				
392.40 TRANSPORTATION EQUIPMENT - TRUCKS > 13,000				383,544.66	2,039,666				
396.00 POWER OPERATED EQUIPMENT				5,248,819.05	5,515,650				
MVP ASSETS									
350.10 LAND				1,843,154.51					
350.20 LAND RIGHTS				52,010,326.11	5,006,463				
352.00 STRUCTURES AND IMPROVEMENTS				22,370,048.26	2,999,962				
353.00 STATION EQUIPMENT				164,183,979.14	22,435,835				
354.00 TOWERS AND FIXTURES				42,081,024.55	3,887,635				
355.00 POLES AND FIXTURES				239,684,022.95	48,667,992				
356.00 OVERHEAD CONDUCTORS AND DEVICES				94,066,212.36	14,562,549				
TOTAL NONDEPRECIABLE AND ACCOUNTS NOT STUDIED				**1,003,211,361.76**	**184,949,612**				
TOTAL ELECTRIC PLANT				**10,860,938,286.38**	**3,109,870,847**	**9,788,600,953**	**378,008,640**		

* INTERIM SURVIVOR CURVES USED. EACH LOCATION HAS A UNIQUE PROBABLE RETIREMENT DATE.
** ANNUAL ACCRUAL AMOUNT IS BASED ON 8.5-YEAR REMAINING LIFE.
*** SEPARATE RESERVE AMORTIZATION TO BE RECOVERED OVER 5 YEARS BEGINNING IN 2023.

Confidential Joint Exhibit C (Redacted)

Agreed Addendum between NIPSCO and the LaPorte County Commissioners to Not Oppose Settlement Agreement between NIPSCO and OUCC, et al. in Cause No. 46120

1) Michigan City Generating Station – Study

As recommended by LaPorte County Witness Gramarossa, NIPSCO agrees to study the potential of converting the Michigan City Generating Station to a combined cycle gas turbine or gas peaker generating plant or locating battery energy storage systems or other energy technologies at the site of the generating station that would generate local tax revenue for the county and keep good paying jobs in LaPorte County. NIPSCO shall use commercially reasonable efforts to complete this study within six (6) months of the issuance of a final order approving the Stipulation and Settlement Agreement in this cause and make a public version of the study available to the LaPorte County Board of Commissioners.

2) LaPorte County Economic Development Study

NIPSCO agrees to study LaPorte County to identify sites/properties that are potentially suitable for locating a large economic development project or a combined cycle gas turbine, gas peaker generating plant, battery energy storage systems, or other energy technologies that would generate local tax revenue and keep good paying jobs in LaPorte County. NIPSCO shall use commercially reasonable efforts to complete this study within six (6) months of the issuance of a final order approving the Stipulation and Settlement Agreement in this cause and make a public version of the study available to the LaPorte County Board of Commissioners.

3) LaPorte County Economic Development – Investment for Site Readiness

Through December 31, 2030, NIPSCO will work with LaPorte County, the NWI Forum, and the IEDC to identify potential economic development property(ies), and so long as LaPorte County and both NWI Forum or IEDC believe they are good property(ies) for investment (meaning, for example, site is certified as clean; it is in a designated economic development or redevelopment area, technology park, etc.; certain condition precedents have taken place such as proper zoning and site plan approval). NIPSCO agrees to make investments of up to $5 million at a property(ies) within LaPorte County to ensure electric service is available for

the property(ies) and enhance the attractiveness of such property(ies) for potential economic development customers.

4) LaPorte County Kingsbury Industrial Park

In Cause No. 44733, NIPSCO agreed to the inclusion of an Economic Development project for LaPorte County Kingsbury Industrial Park, with a stated commitment to invest as much as $3.5 million for distribution system and substation upgrades associated with such a project, once the necessary project plans have been finalized ("Kingsbury Project"). In Cause No. 45557 NIPSCO agreed to extend this commitment in its 2021-2026 Electric TDSIC Plan. NIPSCO is willing to continue to work with LaPorte County and support inclusion of the Kingsbury Project in the TDSIC Plan following the expiration of NIPSCO's 2012-2026 Electric TDSIC Plan and make these funds available through December 31, 2030.

5) Non-Opposition to Any Settlement & Admission of Prefiled Testimony

To the extent a settlement of all issues is reached in this cause and that all parties either support or do not oppose the settlement, the LaPorte County Board of Commissioners agree to not oppose such settlement. However, to the extent a settlement is reached on less than all the issues in this cause, the LaPorte County Board of Commissioners would not be restricted from taking any positions on non-settled issues. NIPSCO agrees to not oppose the admission of the prefiled testimony of all LaPorte County Board of Commissioners witnesses filed in this cause. The LaPorte County Board of Commissioners likewise agrees to not oppose the admission of the prefiled testimony of all NIPSCO witnesses filed in this cause.

6) Reservation of Rights

Nothing in this agreed addendum will be construed to limit the LaPorte County Board of Commissioners' right to intervene in other causes in which NIPSCO or NIPSCO Generation LLC is a petitioner.

ACCEPTED AND AGREED this 5th day of February, 2025.
[SIGNATURE PAGES FOLLOW]

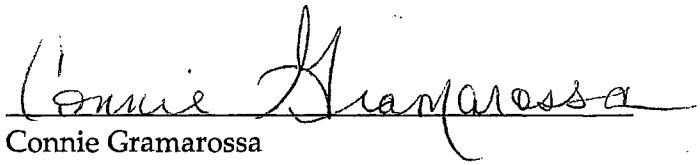
Addendum A
Cause No. 46120

Northern Indiana Public Service Company LLC

Erin A. Whitehead
Vice President, Regulatory and Major Accounts

Addendum A

LaPorte County Board of Commissioners



Connie Gramarossa
President of the LaPorte County Board of Commissioners

Addendum B
Cause No. 46120

Settlement Terms between NIPSCO and the RV Industry User's Group ("RV Group")[1]

- The RV Group will be a signatory to the Settlement Agreement, which includes stipulating to the admissibility of all Settling Parties' prefiled direct, cross-answering and rebuttal testimonies and exhibits, and waiving cross-examination of all Settling Parties' and RV Group witnesses, but RV Group reserves the right to ask questions of any witness that is required to appear, and RV Group members will receive the benefits of all terms, benefits, and obligations under this section as well as the broader Stipulation and Settlement Agreement, including the agreed-to revenue requirement reductions, NIPSCO commitments, and related cost-of-service shifts.
- In Addendum B to the Stipulation and Settlement Agreement approved in Cause No. 45772, NIPSCO committed to fund energy efficiency audits of up to $50,000 per customer for each of the four RV Group members. For each of the three RV Group members in this proceeding, NIPSCO commits an additional $50,000 per customer, for a total of $100,000 per RV Group member for these three members ($50,000 from Cause No. 45772 plus $50,000 from this proceeding) which can be utilized for energy efficiency audits and/or load and usage studies. NIPSCO will also commit to assist with this study and review of the respective RV Group member's specific operational and usage characteristics, with the ultimate goal of determining if a new or adjusted rate structure or schedule is appropriate for these RV Group customers and other customers with similar characteristics who would qualify. NIPSCO and the RV Group members will work together to select a mutually satisfactory, qualified company or consultant to perform these studies. NIPSCO further commits to provide an additional $75,000 in total ($25,000 for each of the three RVG Members in this proceeding), which can be utilized toward performing load and rate studies to determine if adjustments to NIPSCO's existing rate structure or creation of a new rate for the RVG members involved in this case are appropriate to propose in the future which will require the assistance, support, and timely provision of usage and rate design data and details by NIPSCO. As part of these efforts, NIPSCO agrees to make any and all requested and relevant information timely available to the RV Group and/or their consultants, subject to any necessary non-disclosure agreements.

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1 The RV Industry User's Group is comprised of LCI Industries, Inc.; Forest River, Inc.; and Thor Industries.

- NIPSCO agrees to include RV Group representatives in discussions with the DSM Oversight Board related to participating in existing or proposing additional demand response program opportunities available to or that could be expanded to provide additional benefits to RV Group members and lower NIPSCO peak energy needs. NIPSCO is separately committed to issuing a request for information for demand response as part of its next RFP that shall include and allow for RV Group member proposals consistent with these objectives.
- NIPSCO will continue to work separately from the DSM Oversight Board process and directly work with and assist the RV Group representatives in determining potential savings, programs, and funding opportunities through its current DSM programs and any mutually beneficial other demand-side management ("DSM") expanded processes or programs. To the extent savings are identified that are not currently part of NIPSCO's DSM current programs/measures, NIPSCO will make a good faith effort to propose and add such programs/measures to its Commission-approved DSM plan(s).
- As part of its next electric base rate case, subject to any necessary non-disclosure protections, NIPSCO agrees to prepare a 4CP cost of service analysis for purposes allocating production-related costs and make this available to the RV Group in advance of such filing, as well as to any other party subsequently participating in the case who requests it. This analysis shall conform to and be consistent with the principles of cost causation identified by NIPSCO in this and NIPSCO's last base rate case in Cause No. 45772. This does not, however, limit NIPSCO in determining which cost of service analysis it chooses to propose in its case-in-chief, nor does it impact any other parties' right to take any position with regards to cost of service or allocations in that next rate case.
- NIPSCO commits to meeting with RV Group representatives to review and discuss cost of service concerns before NIPSCO files its next electric base rate case is filed.

RV Group TDSIC Project(s)

- NIPSCO and the RV Group agree that the RV Group may propose one or more RV Group specific projects as part of its TDSIC Plan (currently under Cause No. 45557) totaling up to $5.6 Million, provided each project meets the applicable requirements of the TDSIC Statute (Ind. Code ch. 8-1-39). This agreed upon commitment and benefit shall be reserved for the benefit of the RV Group members, and any TDSIC Plan project request made by an RV Group member shall be for qualifying infrastructure upgrade needs that

improve reliability and/or spur economic development, which include, but are not limited to upgrades to substations, transformers, distribution and transmission facilities, or other necessary electrical system upgrades to provide service to an RV Group member ("RV Group TDSIC Project(s)"). This total amount of $5.6 million is inclusive of the $3.5 million RV Group Project fund provided for in Addendum B to the Stipulation and Settlement Agreement approved in Cause No. 45772, with an additional $2.1 million added to such fund.[2] Any RV Group TDSIC Project may be pursued as part of NIPSCO's existing TDSIC process in Cause No. 45557 or in subsequent TDSIC plans if the total $5.6 million has not been utilized. The Fund shall not lapse or be transferred to other NIPSCO customers, but any NIPSCO system upgrades or facilities built to support any RV Group TDSIC Project(s) may also be used to serve other customers, provided this does not diminish service reliability for the RV Group TDSIC Project(s), and the Fund shall continue until fully utilized for RV Group TDSIC Project(s).

- RV Group TDSIC Project(s) shall include any-and-all projects that qualify under the TDSIC Statute. NIPSCO will file for approval of the RV Group TDSIC Project(s) to allow the RV Group TDSIC Projects to include as many qualifying types of projects as possible, including: (i) RV Group operation or production facility updates or expansions that will result in continued or increased energy demand or continued or increased employment by the applying RV Group member from new capital investments made within the NIPSCO service territory; (ii) support of RV Group member renewable energy projects, energy efficiency and demand response, or peak load reduction projects; and (iii) any advanced or smart meter technology that will assist an RV Group member in reducing peak load. To the extent that a project proposed by an RV Group member does not qualify under the TDSIC Statute but would qualify under NIPSCO's DSM tracker, NIPSCO will seek inclusion of qualifying projects in the DSM tracker, and these projects would not count against the $5.6 million total RV Group TDSIC Project amount.
- Each of the RV Group members shall be entitled to request one or more RV Group TDSIC Project(s) subject to the review and support of NIPSCO, which support and approval shall not be unreasonably withheld or delayed. Any

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[2] This new $2.1 million fund shall be available to the RV Industry User's Group comprised of LCI Industries, Inc., Forest River, Inc., and Thor Industries. The prior 45772 $3.5 million fund shall be carried forward and continued to be made available to the RV Industry User's Group that was comprised of LCI Industries, Inc., Forest River, Inc., Thor Industries, and Patrick Industries.

requests to support RV Group TDSIC Project(s) from the Fund will be presented in a tracker filing by NIPSCO in Cause No. 45557-TDSIC-X (or successor docket), which will require and provide a sufficient evidentiary showing consistent with the TDSIC Statute for the approval of such amounts.

- All other participating Parties in the then pending TDSIC docket shall be provided notice of and reserve the right to timely take any position on such RV Group TDSIC Project(s) funding request when the request is formally presented in the TDSIC tracker filing.
- NIPSCO and the RV Group shall work together in good faith to establish precise administrative details for applications or requests for RV Group TDSIC Project(s), and such applications or requests can be made any time after approval of the Settlement Agreement, consistent with the language and requirements herein.

ACCEPTED AND AGREED this 7th day of February, 2025.

[SIGNATURE PAGES FOLLOW]

Addendum B
Cause No. 46120

Northern Indiana Public Service Company LLC

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Addendum B
Cause No. 46120

RV Industry User's Group

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 107
Vectren 2014 IRP

VECTREN
Live Smart

Vectren Corporation
2014 Integrated Resource Plan

By
Southern Indiana Gas and Electric Company
d/b/a Vectren Energy Delivery of Indiana, Incorporated

November 1, 2014

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IRP Proposed Draft Rule Requirements Cross Reference Table

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-4	**Methodology and documentation requirements**	
	(a) The utility shall provide an IRP summary document that communicates core IRP concepts and results to non-technical audiences. (1) The summary shall provide a brief description of the utility's existing resources, preferred resource portfolio, short term action plan, key factors influencing the preferred resource portfolio and short term action plan, and any additional details the commission staff may request as part of a contemporary issues meeting. The summary shall describe, in simple terms, the IRP public advisory process, if applicable, and core IRP concepts, including resource types and load characteristics. (2) The utility shall utilize a simplified format that visually portrays the summary of the IRP in a manner that makes it understandable to a non-technical audience. (3) The utility shall make this document readily accessible on its website.	Technical Appendix J and www.vectren.com/irp
	(b) An IRP must include the following: (1) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.	Included throughout the IRP

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-4 Cont.	(2) The data sets, including data sources, used to establish base and alternative forecasts. A third party data source may be referenced. The reference must include the source title, author, publishing address, date, and page number of relevant data. The data sets must include an explanation for adjustments. The data must be provided on electronic media, and may be submitted as a file separate from the IRP, or as specified by the commission.	72, 190-191, Technical Appendix sections: A, B, D, E, F, I
	(3) A description of the utility's effort to develop and maintain a data base of electricity consumption patterns, by customer class, rate class, NAICS code, and end-use. The data base 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.	72
	(4) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.	92
	(5) A discussion of distributed generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting.	84-85
	(6) A complete discussion of the alternative forecast scenarios developed and analyzed, including a justification of the assumptions and modeling variables used in each scenario.	66-89, 186-200
	(7) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.	190
	(8) A discussion of how the utility's emission allowance inventory and procurement practices for any air emission regulated through an emission allowance system have been taken into account and influenced the IRP development.	51-55
	(9) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	186-192

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-4 Cont.	(10) A brief description and discussion within the body of the IRP focusing on the utility's Indiana jurisdictional facilities with regard to the following components of FERC Form 715: (A) 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 simulation must include the capability of meeting the standards of the North American Electric Reliability Corporation (NERC). (C) Reliability criteria for transmission planning as well as the assessment practice used. The information and discussion must include the limits set of its transmission use, its assessment practices developed through experience and study, and certain operating restrictions and limitations particular to it. (D) Various aspects of any joint transmission system, ownership, and operations and maintenance responsibilities as prescribed in the terms of the ownership, operation, maintenance, and license agreement.	175-183
	(11) An explanation of the contemporary methods utilized by the utility in developing the IRP, including a description of the following:	
	(A) Model structure and reasoning for use of particular model or models in the utility's IRP.	66-67, 186-187
	(B) The utility's effort to develop and improve the methodology and inputs for its:	32, 186
	(i) forecast;	32, 93
	(ii) cost estimates;	32, 99, 190-191
	(iii) treatment of risk and uncertainty; and	32, 190
	(iv) evaluation of a resource (supply-side or demand-side) alternative's contribution to system wide reliability. The measure of system wide reliability must cover the reliability of the entire system, including:	32
	(AA) transmission; and	176-177
	(BB) generation.	32

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-4 Cont.	(12) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. Avoided cost shall include, but is not limited to, the following: (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 fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.	139, Technical Appendix B
	(13) The actual demand for all hours of the most recent historical year available, which shall be submitted electronically and may be a separate file from the IRP. For purposes of comparison, a utility must maintain three (3) years of hourly data.	Technical Appendix G
	(14) Publicly owned utilities shall provide a summary of the utility's: (A) most recent public advisory process; (B) key issues discussed; (C) how they were addressed by the utility.	20-21, Technical Appendix A
170 IAC 4-7-5	**Energy and demand forecasts**	
	(a) An electric utility subject to this rule shall prepare an analysis of historical and forecasted levels of peak demand and energy usage which includes the following:	
	(1) Historical load shapes, including, but not limited to, the following:	90-92, Technical Appendix C
	(A) Annual load shapes.	
	(B) Seasonal load shapes.	
	(C) Monthly load shapes.	
	(D) Selected weekly and daily load shapes. Daily load shapes shall include, at a minimum, summer and winter peak days and a typical weekday and weekend day.	
	(2) Historical and projected load shapes shall be disaggregated, to the extent possible, by customer class, interruptible load, and end-use and demand-side management program.	
	(3) Disaggregation of historical data and forecasts by customer class, interruptible load, and end-use where information permits.	28, 69
	(4) Actual and weather normalized energy and demand levels.	90

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-5 Cont.	(5) A discussion of all methods and processes used to normalize for weather.	72-73
	(6) A minimum twenty (20) year period for energy and demand forecasts.	67-71
	(7) An evaluation of the performance of energy and demand forecasts for the previous ten (10) years, including, but not limited to, the following: (A) Total system. (B) Customer classes or rate classes, or both. (C) Firm wholesale power sales.	94-96
	(8) Justification for the selected forecasting methodology.	66-67, 76-77
	(9) For purposes of subdivisions (1) and (2), a utility may use utility specific data or more generic data, such as, but not limited to, the types of data described in section 4(b)(2) of this rule.	89
	(b) A utility shall provide at least three (3) alternative forecasts of peak demand and energy usage. At a minimum, the utility shall include high, low, and most probable energy and peak demand forecasts based on alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (4) Changes in technology. (5) Behavioral factors affecting customer consumption. (6) State and federal energy policies. (7) State and federal environmental policies.	70-71
170IAC 4-7-6	**Resource Assessment**	
	(a) The utility shall consider continued use of an existing resource as a resource alternative in meeting future electric service requirements. The utility shall provide a description of the utility's existing electric power resources that must include, at a minimum, the following information:	189
	(1) The net dependable generating capacity of the system and each generating unit.	189
	(2) The expected changes to existing generating capacity, including, but not limited to, the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	28
	(3) A fuel price forecast by generating unit.	190-191

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170IAC 4-7-6 Cont.	(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 each existing fossil fueled generating unit.	51-58
	(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 transmission losses, congestion, and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network. (D) An assessment of the transmission component of avoided cost.	175-183
	(6) A discussion of demand-side programs, including existing company-sponsored and government-sponsored or mandated energy conservation or load management programs available in the utility's service area and the estimated impact of those programs on the utility's historical and forecasted peak demand and energy.	69, 121-131, 152-171
	The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall also be provided for each year of the planning period.	
	(b) 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. For a utility-sponsored program identified as a potential demand-side resource, the utility's IRP shall, at a minimum, include the following:	122-129
	(1) A description of the demand-side program considered.	153-171
	(2) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to resources under consideration such as project life and seasonal operation.	140
	(3) The customer class or end-use, or both, affected by the program.	153-171
	(4) A participant bill reduction projection and participation incentive to be provided in the program.	153-171

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170IAC 4-7-6 Cont.	(5) A projection of the program cost to be borne by the participant.	153-171
	(6) Estimated energy (kWh) and demand (kW) savings per participant for each program.	153-171
	(7) The estimated program penetration rate and the basis of the estimate.	153-171
	(8) The estimated impact of a program on the utility's load, generating capacity, and transmission and distribution requirements.	153-171
	(c) A utility shall consider a range of supply-side resources including cogeneration and nonutility generation as an alternative in meeting future electric service requirements. This range shall include commercially available resources or resources the director may request as part of a contemporary issues technical conference. The utility's IRP shall include, at a minimum, the following:	109, 112
	(1) Identify and describe the resource considered, including the following:	109
	(A) Size (MW).	109
	(B) Utilized technology and fuel type.	109
	(C) Additional transmission facilities necessitated by the resource.	180-182
	(2) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	N/A
	(d) A utility shall consider new or upgraded transmission facilities as a resource in meeting future electric service requirements, including new projects, efficiency improvements, and smart grid resources. The IRP shall, at a minimum, include the following: (1) A description of the timing and types of expansion and alternative options considered. (2) The approximate cost of expected expansion and alteration of the transmission network. (3) A description of how the IRP accounts for the value of new or upgraded transmission facilities for the purposes of increasing needed power transfer capability and increasing the utilization of cost effective resources that are geographically constrained.	175-183

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170IAC 4-7-6 Cont.	(4) A description of how: (A) IRP data and information are used in the planning and implementation processes of the RTO of which the utility is a member; and (B) RTO planning and implementation processes are used in and affect the IRP.	38-48
170 IAC 4-7-7	**Selection of future resources**	
	(a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in sections 6(b) through 6(c) 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, but not limited to, a resource summary table. The following information: (1) Significant environmental effects, including the following: (A) Air emissions. (B) Solid waste disposal. (C) Hazardous waste and subsequent disposal. (D) Water consumption and discharge.	109
	(2) An analysis of how existing and proposed generation facilities conform to the utility-wide plan to comply with existing and reasonably expected future state and federal environmental regulations, including facility-specific and aggregate compliance options and associated performance and cost impacts.	188
	(b) Integrated resource planning includes one (1) or more tests used to evaluate the cost effectiveness of a demand-side resource option. A cost-benefit analysis must be performed using the following tests except as provided under subsection (e): (1) Participant. (2) Ratepayer impact measure (RIM). (3) Utility cost (UC). (4) Total resource cost (TRC). (5) Other reasonable tests accepted by the commission.	137-151
	(c) A utility is not required to express a test result in a specific format. However, a utility must, in all cases, calculate the net present value of the program impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the discount rate used in the test.	138, 153-154
	(d) A utility is required to:	
	(1) specify the components of the benefit and the cost for each of the major tests; and	137-138
	(2) identify the equation used to express the result.	137

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-7 Cont.	(e) If a reasonable cost-effectiveness analysis for a demand-side management program cannot be performed using the tests in subsection (b), where it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.	137-151
	(f) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.	N/A
170 IAC 4-7-8	**Resource integration**	
	(a) The utility shall develop candidate resource portfolios from the selection of future resources in section 7 and provide a description of its process for developing its candidate resource portfolios.	186-187
	(b) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and provide, at a minimum, the following information:	193-201
	(1) Describe the utility's preferred resource portfolio.	193-194, 201
	(2) Identify the variables, standards of reliability, and other assumptions expected to have the greatest effect on the preferred resource portfolio.	202-211
	(3) Demonstrate that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis.	171-172
	(4) Demonstrate that the preferred resource portfolio utilizes, to the extent practical, all economical load management, demand side management, technology relying on renewable resources, cogeneration, distributed generation, energy storage, transmission, and energy efficiency improvements as sources of new supply.	84-89, 109, 112, 122-132, 171-172
	(5) Discuss the utility's evaluation of targeted DSM programs including their impacts, if any, on the utility's transmission and distribution system for the first ten (10) years of the planning period.	179, 137-140

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-8 Cont.	(6) Discuss the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio. The discussion of the preferred resource portfolio shall include, where appropriate, the following: (A) Operating and capital costs. (B) The average cost per kilowatt-hour, 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.	N/A
	(7) Demonstrate how the preferred resource portfolio balances cost minimization with cost effective risk and uncertainty reduction, including the following. (A) Identification and explanation of assumptions. (B) Quantification, where possible, of assumed risks and uncertainties, which may include, but are not limited to: See below. (i) regulatory compliance; (ii) public policy; (iii) fuel prices; (iv) construction costs; (v) resource performance; (vi) load requirements; (vii) wholesale electricity and transmission prices; (viii) RTO requirements; and (ix) technological progress. (C) An analysis of how candidate resource portfolios performed across a wide range of potential futures.	201-212
	(D) The results of testing and rank ordering the candidate resource portfolios by the present value of revenue requirement and risk metric(s). The present value of revenue requirement shall be stated in total dollars and in dollars per kilowatt-hour delivered, with the discount rate specified.	Technical Appendix H

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-8 Cont.	(E) An assessment of how robustness factored into the selection of the preferred resource portfolio.	201-212
	(8) Demonstrate, to the extent practicable and reasonable, that the preferred resource portfolio incorporates a workable strategy for reacting to unexpected changes. A workable strategy is one that allows the utility to adapt to unexpected circumstances quickly and appropriately. Unexpected changes include, but are not limited to, the following: See below. (A) The demand for electric service. (B) The cost of a new supply-side or demand-side technology. (C) Regulatory compliance requirements and costs. (D) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	201-212
170 IAC 4-7-9	**Short term action plan**	
	Sec. 9. A short term action plan shall be prepared as part of the utility's IRP, and shall cover each of the three (3) years beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(b)(8), where the utility must take action or incur expenses during the three (3) year period. The short term action plan must include, but is not limited to, the following: (1) A description of each resource in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective. (2) The implementation schedule for the preferred resource portfolio. (3) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts. (4) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually transpired.	215-216

List of Acronyms/Abbreviations

AC	Air Conditioning
ACS	American Community Survey
AMI	Advanced Metering Infrastructure
APWR	Advanced Pressurized Water Reactor
ARRA	American Recovery and Reinvestment Act
ASPEN-OneLiner	Advanced Systems for Power Engineering, Incorporated
AUPC	Average Use Per Customer
B	Water Heating Service – Closed to new customers
BAGS	Broadway Avenue Gas Turbines
BPJ	Best Professional Judgment
BPM	MISO's Business Practice Manual
BTU	British Thermal Unit
CAA	Clean Air Act
CAC	Citizens Action Coalition
CAES	Compressed Air Energy Storage
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Days
CEII	Critical Electric Infrastructure Information
CFL	Compact Fluorescent Lighting
CHP	Combined Heat and Power
CIL	Capacity Import Limit
CO_2	Carbon Dioxide
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CVR	Conservation Voltage Reduction
CWA	Clean Water Act
DA	Distribution Automation
DGS	Demand General Service
DLC	Direct Load Control
DOE	United States Department of Energy
DR	Demand Response
DRR-1	Demand Response Resource Type 1
DSM	Demand-side Management
DSMA	Demand Side Management Adjustment
EAP	Energy Assistance Program
ECM	Electronically Commutated Motor
EDR	Emergency Demand Response
EEFC	Energy Efficiency Funding Component
EGU	Electric Generating Units
EIA	Energy Information Administration
EISA	Energy Independence and Security Act
ELGS	Effluent Limit Guidelines and Standards
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
EVA	Energy Ventures Analysis, Inc.
FERC	Federal Energy Regulatory Commission
FF	Fabric Filter
FGD	Flue Gas Desulfurization
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GS	General Service
GWH	Gigawatt Hour
HAP	Hazardous Air Pollutants
HCi	Hydrochloric Acid

List of Acronyms/Abbreviations (continued)

HDD	Heating Degree Days
HHV	Higher Heating Value
HLF	High Load Factor
HRSG	Heat Recovery Steam Generator
HSPF	Heating Seasonal Performance Factor
HVAC	Heating, Ventilation, and Air Conditioning
ICAP	Interconnection Installed Capacity
IDEM	Indiana Department of Environmental Management
IGCC	Integrated Gasification Combined Cycle
IPP	Independent Power Producers
IRP	Integrated Resource Plan
IOU	Investor-Owned Utility
IURC	Indiana Utility Regulatory Commission
kV	Kilovolt
kVA	Kilovolt-Ampere
kWh	Kilowatt Hour
LBA	Load Balancing Area
LCR	Local Clearing Requirement
LMR	Load Management Receivers
LP	Large Power
LRZ	Local Resource Zone
LOLE	Loss of Load Expectation
LSE	Load Serving Entity
MACT	Maximum Achievable Control Technology Standards
MAPE	Mean Absolute Percentage Error
MARS	Multi-Area Reliability Simulation
MATS	mercury and Air Toxics Standards
MECT	Module E Capacity Tracking
MGD	Millions of Gallons per Day
MISO	Midcontinent Independent System Operator
MLA	Municipal Levee Authority
MMBTU	One million British Thermal Unit
MSA	Metropolitan Statistical Area
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt Hour
NAICS	North American Industry Classification System
NDC	Net Dependable Capacity
NERC	North American Electric Reliability Council
NERC MOD	NERC Modeling, Data, and Analysis
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrous Oxide
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NSPS	New Source Performance Standards
O&M	Operation and Maintenance
ORSANCO	Ohio River Valley Sanitation Commission
OSS	Off Season Service
OUCC	Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PJM	Pennsylvania New Jersey Maryland Interconnection LLC
PM	Particulate Matter
PRM	Planning Reserve Margin
PTI-PSS/E	Power Technologies Incorporated's Power System Simulator Program for Engineers
PV	Photovoltaic
PVRR	Present Value of Revenue Requirements
RBS	Residential Behavioral Savings

List of Acronyms/Abbreviations (continued)

RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
RECB	Regional Expansion Criteria and Benefits
RFC	Reliability First Corporation
RIM	Ratepayer Impact Measure
RPS	Renewable Portfolio Standard
RS	Residential Service
SAE	Statistically Adjusted End-use
SCADA	Supervisory Control and Data Acquisition
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SEER	Seasonal Energy Efficiency Ratio
SGS	Small General Service
SGT	Steam Turbine Generator
SIP	System Integration Plan
SMR	Small Modular Reactors
SO_2	Sulfur Dioxide
TPA	Third Party Administrator
TRC	Total Resource Cost
TVA	Tennessee Valley Authority
UCAP	Unforced Capacity Rating
VUHI	Vectren Utility Holdings Inc.
ZRC	Zone Resource Credit

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CHAPTER 1
EXECUTIVE SUMMARY

COMPANY BACKGROUND

Vectren Corporation is an energy holding company headquartered in Evansville, Indiana. Vectren's wholly owned subsidiary, Vectren Utility Holdings, Inc. (VUHI), is the parent company for three operating utilities: Indiana Gas Company, Inc. (Vectren North), Southern Indiana Gas and Electric Company (Vectren), and Vectren Energy Delivery of Ohio (VEDO).

Vectren North provides energy delivery services to more than 570,000 natural gas customers located in central and southern Indiana. Vectren provides energy delivery services to over 142,000 electric customers and approximately 110,000 gas customers located near Evansville in southwestern Indiana. VEDO provides energy delivery services to approximately 312,000 natural gas customers near Dayton in west central Ohio.

Vectren's company-owned generation fleet represents 1,158 megawatts (MW)[1] of unforced capacity (UCAP) as shown in Table 1-1.

Table 1-1 Generating Units

Unit	UCAP (MW)	Primary fuel	Commercial Date
Northeast 1	9 MW	Gas	1963
Northeast 2	9 MW	Gas	1964
FB Culley 2	83 MW	Coal	1966
Warrick 4	135 MW	Coal	1970
FB Culley 3	257 MW	Coal	1973
AB Brown 1	228 MW	Coal	1979
BAGS 2	59 MW	Gas	1981
AB Brown 2	233 MW	Coal	1986
AB Brown 3	73 MW	Gas	1991
AB Brown 4	69 MW	Gas	2002
Blackfoot	3 MW	Landfill Gas	2009

[1] Blackfoot landfill gas project is considered behind-the-meter and is therefore currently accounted for as a reduction to load and is omitted from the capacity total

In addition to company owned generating resources, Vectren has access to an additional 30 MW of capacity as a result of its 1.5% ownership interest in Ohio Valley Electric Corporation (OVEC). Vectren is also contracted to receive 80 MW of nominal capacity wind energy through two separate long-term purchase power agreements. The total firm capacity credit for the MISO 2014-2015 planning year for these wind resources is 7.3 MW. Vectren is interconnected with other utilities at both 345 kV and 138 kV and is able to exchange capacity and energy through the market mechanisms of the Midcontinent Independent System Operator (MISO).

THE IRP PROCESS

The Integrated Resource Plan (IRP) process was developed to assure a systematic and comprehensive planning process that produces a reliable, efficient approach to securing future resources to meet the energy needs of the utility and its customers. The IRP process encompasses an assessment of a range of feasible supply-side and demand-side alternatives to establish a diverse portfolio of options to effectively meet future generation needs.

In Indiana, the IRP is also guided by rules of the Indiana Utility Regulatory Commission (IURC). Those rules, found in the Indiana Administrative Code at 170 I.A.C. 4-7-4 through 4-7-9, provide specific guidelines for plan contents and filing with the Commission. On October 14, 2010, the IURC issued an order to commence rulemaking to revise/update the current Indiana IRP rule. The following summer, Vectren participated in a stakeholder process to provide input on updating the rule. The proposed draft rule was sent to stakeholders on October 4, 2012. Although not finalized, Vectren voluntarily followed the proposed draft rule, which is found in the IRP Proposed Draft Rule Requirements Cross Reference Table of this IRP.

Vectren modified its processes to meet the proposed draft rule. Most notably, Vectren incorporated a stakeholder process to gather input from stakeholders and answer stakeholder questions in an open, transparent process. The proposed rule requires at

least 2 meetings with stakeholders. On March 20, 2014, Vectren met with stakeholders to discuss the base inputs of the plan, educate stakeholders on IRP related topics, and review the Vectren process. Based on feedback from stakeholders, Vectren added an additional meeting on August 5, 2014 to further discuss major assumptions and data inputs prior to modeling. Finally, on September 24, 2014 Vectren presented a preview of the plan. A summary of the stakeholder meetings can be found in Chapter 2 Planning Process, and the meeting presentations and Q&A summaries are found in the Technical Appendix, section A.

Details of the process used by Vectren to develop the recommended plan in this IRP are found in chapters 2 through 11 of this report. Chapter 11 Action Plan sets forth the action plan for Vectren over the next three years to achieve the long-term resource objectives described in this IRP.

Included in the process is an updated demand and energy forecast (detailed in Chapter 5 Sales and Demand Forecast). Table 1–2, shows a summary of the demand and energy forecast.

VECTREN'S QUANTITATIVE AND QUALITATIVE IRP PROCESS

Historically, Vectren has used modeling to perform the evaluations, screenings, and assessments of various potential scenarios to arrive at a single plan that represented its "Resource Plan Additions." Vectren continues to use the Strategist modeling software from Ventyx, as it has in its last several IRP studies. This software has traditionally been used by some of the other Indiana utilities, as well. The submitted plan was the result of a process that was primarily a quantitative evaluation performed using an industry standard planning model.

The modeling performed by Vectren provides important information to evaluate future resource needs. However, Vectren will also continue to monitor developments that

could impact future resource needs. Three developments that Vectren is focusing on for impacts on the near term are:

1. The Clean Power Plan from the Environmental Protection Agency (EPA) and Indiana's approach to implementing this rule.
2. MISO capacity market constraints resulting from the early retirements of coal units as a response to the EPAs MATS rule.
3. The impacts on Vectren's load due to the addition of or loss of large customer load.

While Vectren's models attempt to evaluate the impact those issues may have on its future load, significant uncertainty remains. Vectren must maintain flexibility to adjust its plans based on the outcome of these and other unknown factors. In the case of Vectren, one of the smallest investor-owned electric utilities in the nation, the ramifications of major capacity decisions are particularly important.

Equally important, Vectren believes one of the major objectives of the Commission's reporting and filing requirements regarding the IRP process is to communicate with the IURC regarding the decision processes, evaluations, and judgments that Vectren uses to assist in making the resource planning decisions that are in the long-term best interest of Vectren's customers and the communities it serves. Vectren understands that the action plan which results from the IRP process is to be used as a guide by the Company and the IURC in addressing long-term resource needs, as both attempt to carry out their respective responsibilities in the most effective manner possible.

CHANGES SINCE LAST IRP

While a number of changes have occurred since Vectren's last IRP, four specific changes have had a significant impact on this IRP. First, the IURC's proposed draft IRP rules were released after Vectren's last IRP. Vectren is voluntarily following the new proposed draft IRP rule, which includes a stakeholder process, non-technical summary, more robust risk analysis, and attending an annual contemporary issues meeting in Indianapolis. The IRP Proposed Draft Rule Requirements Cross Reference Table on

page three shows the new proposed draft rule and where Vectren addresses each part in this IRP.

Second, Vectren engaged a third party consultant with significant experience conducting IRPs for other parties, Burns & McDonnell, one of the leading engineering design experts in the United States, to aid its preparation of this IRP. For the 2014 IRP, Vectren worked closely with Burns and McDonnell to perform Strategist modeling (including additional DSM modeling). Burns and McDonnell has a great deal of experience in working with companies across the country on resource modeling. They also performed the Technology Assessment, detailing costs for potential resource options. The Technology Assessment can be found in the Technical Appendix, section B.

Third, the EPA has finalized various federal mandates with respect to further environmental regulation of Vectren's generating units and proposed a sweeping greenhouse gas regulation for existing coal-fired generating sources since Vectren's last IRP. As will be discussed in more detail in Chapter 4 Environmental, the EPA finalized its Mercury and Air Toxics Standard (MATS) in 2012, which set first ever plant-wide emission limits for mercury and other hazardous air pollutants and has a compliance deadline of April 2015. MATS has resulted in many announcements of coal plant retirements across the US. As a result, MISO, Vectren's Regional Transmission Operator (RTO), is predicting potential capacity shortfalls in the next few years. In the next two years Vectren intends to spend $70- $90 million on its environmental compliance program to meet not only the MATS rule, but also recent water discharge limits for mercury contained in water discharge permit renewals and mitigate incremental sulfur trioxide (SO_3) emissions resulting from the installation of Vectren's selective catalytic reduction technology under an agreement with the EPA. However, Vectren is projecting to defer recovery of these federally mandated costs until approximately 2020. The assumptions in the IRP are consistent with Vectren's environmental compliance filing.

In addition to the federal mandates referenced above, the EPA released its final rule regulating cooling water structures under Section 316(b) of the Clean Water Act (CWA) on August 15, 2014. Section 316(b) requires that intake structures that withdraw > 2 Million Gallons per Day (MGD) of water, including most electric generating units, use the "Best Technology Available" to prevent and / or mitigate adverse environmental impacts to shellfish, fish, and wildlife in a water body. This rule applies only to the FB Culley plant, as the AB Brown plant already utilizes cooling water towers.

Finally, on June 2, 2014, the EPA issued the Clean Air Act Section 111(d) Greenhouse Gas (GHG) New Source Performance Standards (NSPS) for existing sources, known as the Clean Power Plan (CPP). The CPP sets state-specific carbon reduction goals based on a state's existing generation mix based upon a building block approach and provides guidelines for the development, submission and implementation of state plans to achieve the state goals. As yet, there is little clarity on how the state of Indiana will choose to implement this rule. However, this IRP considers several of the potential building blocks in its assumptions: Demand Side Management (DSM), a potential renewables portfolio standard, and a price for carbon price beginning in 2020.

Fourth, the Indiana General Assembly passed legislation in March of 2014 that modified DSM requirements in Indiana. Senate Enrolled Act No. 340 ("SEA 340") removed requirements for mandatory statewide "Core" DSM programs and energy savings goals effective December 31, 2014. SEA 340 also allows large Commercial and Industrial (C&I) customers who meet certain criteria to opt-out of participating in utility sponsored DSM programs.

Vectren continues to support DSM related energy efficiency efforts as a fundamental part of the services that are provided to customers in order to help them manage their energy bills. Vectren believes that a cost effective level of DSM energy efficiency may be supported by policy considerations beyond the IRP's focus on planning for future

resources. Consistent with this belief, Vectren's base sales forecast includes a base level of DSM at a targeted level of 1% eligible annual savings for 2015 – 2019 and 0.5% annually thereafter for customer load that has not opted-out of DSM programs.

Vectren also modeled whether incremental DSM energy efficiency programs would be selected as a resource when competing with supply side options, to meet future electric requirements. Vectren's approach attempts to balance its commitment to a level of cost-effective DSM to help customers manage their energy bills, while evaluating additional DSM resources consistent with least cost planning.

Note that since the last IRP was performed, Broadway Unit 1 (BAGS 1) has quit performing up to specifications. The unit has been on a long-term outage. Therefore, Vectren currently does not get credit for the unforced capacity (UCAP) amount, and it was not included in the analysis as shown in Table 1-1. BAGS 1 is a natural gas peaking unit, and in the past was typically good for approximately 40 MW on a UCAP basis.

PLAN RESULTS / RECOMMENDATIONS

The IRP indicates that Vectren does not need any incremental generation resources or purchase power agreements during the planning horizon. Although the IRP does not project incremental resource needs, Vectren proposes to continue offering DSM programs to help customers use less energy, thus lowering their total bill. The IRP forecasts that there may be some marginal economic benefit to retiring FB Culley 2 in 2020 under certain scenarios. This retirement evaluation is influenced by Vectren's load forecast, carbon costs, and fuel costs. Vectren will continue to evaluate the impact of these components on Culley Unit 2 in successive IRPs to evaluate the optimal time to retire Culley Unit 2.

As mentioned above and discussed in further detail in this IRP, the decision to retire FB Culley 2 will not be made until major near term uncertainties become more clear, most

notably how the state of Indiana will implement the EPA's Clean Power Plan (if the plan survives legal challenges). Additionally, Vectren is actively working to attract new industrial customers through economic development activities in southwestern Indiana. If a large customer chooses to locate within the Vectren electric service area, Culley 2 will be required to operate at least in the short term to provide the resources necessary to serve such a customer. Leaving Culley Unit 2 in operation at this time provides Vectren maximum flexibility to adapt to such future developments. Economic modeling does not necessarily account for all such developments that are very possible, and therefore, judgment must also be part of the analysis. Table 1-2 shows the peak and energy forecast. Table 1-3 shows that no capacity additions are currently deemed necessary.

Vectren's base case scenario assumptions are detailed in Chapter 10 Generation Planning. In summary, Vectren assumed a minimum planning margin of 7.3%[1] for each year of the study. Energy savings goals of 1% of eligible customer load were incorporated into the load forecast through 2019. Additionally, incremental energy savings of .5% per year were assumed beginning in 2020 and were carried throughout the rest of the planning period. All assumptions are discussed in depth throughout this IRP.

Sensitivity risk analyses were performed around coal, gas, energy, and carbon pricing, capital costs, and high environmental regulation cost. These results are shown in Chapter 10 Generation Planning.

CONCLUSION

Vectren recognizes that the electric utility industry is experiencing a fast-changing time in terms of potential regulations, environmental mandates, and technology advances. Given the significant impact of any resource decision on both customers and other stakeholders, Vectren will continue to actively monitor developments in the regulatory,

[1] MISO unforced capacity (UCAP) requirement, further discussed in Chapter 3 MISO

environmental, and technology arenas for both their impact on future generation needs and existing facilities. Open communication with the IURC and other parties including the OUCC will be key to Vectren's ability to make the best decisions for all stakeholders.

Table 1-2 Peak and Energy Forecast

Year	Peak (MW)[1]	Annual Energy (GWh)
2014 Proj.	1,145	5,782
2015	1,155	5,914
2016	1,156	5,936
2017	1,113	5,514
2018	1,109	5,503
2019	1,106	5,494
2020	1,106	5,497
2021	1,106	5,492
2022	1,107	5,494
2023	1,107	5,494
2024	1,107	5,496
2025	1,106	5,487
2026	1,106	5,487
2027	1,107	5,492
2028	1,109	5,507
2029	1,110	5,509
2030	1,111	5,517
2031	1,111	5,523
2032	1,113	5,540
2033	1,114	5,548
2034	1,115	5,560
Compound Annual Growth Rate, 2014-2034	-0.1%	-0.2%

[1] Includes wholesale contract sales for 2014

Table 1-3 Base Case Resource Plan

Year	Firm Peak Demand[1] (MW)	UCAP Company Owned Generation (MW)	DLC (MW)	Interruptible (MW)	UCAP Committed Purchases (MW)	Capacity Additions (MW)	Total Resources (MW)	Reserve Margin (%)[2]
2015	1,155	1,155	17	50	38		1,260	9.1%
2016	1,156	1,155	17	50	38		1,260	9.0%
2017	1,113	1,155	18	27	38		1,238	11.2%
2018	1,109	1,155	18	27	38		1,238	11.6%
2019	1,106	1,155	17	28	38		1,238	11.9%
2020	1,106	1,155	17	28	38		1,238	11.9%
2021	1,106	1,155	17	28	38		1,238	11.9%
2022	1,107	1,155	17	28	38		1,238	11.8%
2023	1,107	1,155	17	28	38		1,238	11.8%
2024	1,107	1,155	17	28	38		1,238	11.8%
2025	1,106	1,155	17	28	38		1,238	11.9%
2026	1,106	1,155	17	28	38		1,238	11.9%
2027	1,107	1,155	17	28	38		1,238	11.8%
2028	1,109	1,155	17	28	38		1,238	11.6%
2029	1,110	1,155	17	28	38		1,238	11.5%
2030	1,111	1,155	17	28	38		1,238	11.4%
2031	1,111	1,155	17	28	38		1,238	11.4%
2032	1,113	1,155	17	28	38		1,238	11.2%
2033	1,114	1,155	17	28	38		1,238	11.1%
2034	1,115	1,155	17	28	38		1,238	11.0%

[1] Vectren is not forecasting firm wholesale contracts throughout this forecast.
[2] MISO requires a 7.3% Planning Reserve

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CHAPTER 2

PLANNING PROCESS

INTRODUCTION

Vectren's IRP objectives are based on the need for a resource strategy that provides value to its customers, communities, and shareholders. In addition, this strategy must accommodate the ongoing changes and uncertainties in the competitive and regulated markets. Specifically, Vectren's IRP objectives are as follows:

- Provide all customers with a reliable supply of energy at the least cost reasonably possible
- Develop a plan with the flexibility to rapidly adapt to changes in the market while minimizing risks
- Provide high-quality, customer-oriented services which enhance customer value
- Minimize impacts of Vectren's past and current operations on local environments

PLANNING PROCESS

The planning process is driven by the characteristics of Vectren's markets and the needs of its customers. These elements serve to define the utility's objectives and help establish a long-term forecast of energy and demand.

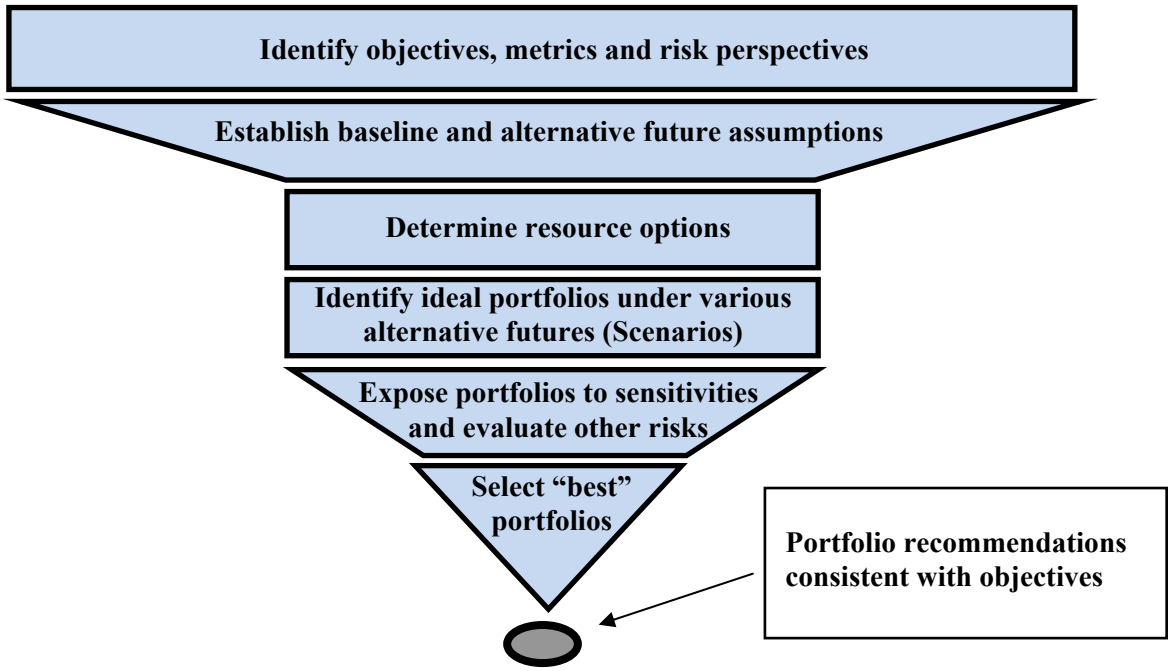
Using the forecast as a baseline, the IRP process entails evaluation of both supply-side and demand-side options designed to address the forecast. These options serve as input into a formal integration process that determines the benefits and costs of various combinations of supply-side and demand-side resources. Because the IRP modeling process requires significant amounts of data and assumptions from a variety of sources, a process is needed to develop appropriate inputs to the models.

The process criteria for inputs include:

- Maintain consistency in developing key assumptions across all IRP components
- Incorporate realistic estimates based on up-to-date documentation with appropriate vendors and available market information, as well as internal departments

- Consideration of impacts and experiences gained in prior IRP processes and demand-side program efforts

Vectren follows an integrated resource plan process that is very similar to other utilities throughout the country. In order to stay current with IRP methodologies and techniques, Vectren works with consultants, attends integrated resource planning conferences, and attends the annual contemporary issues meeting (hosted by the IURC). The diagram below illustrates the general process.



Vectren's objective is to serve customers as reliably and economically as possible, while weighing future risks and uncertainties. Vectren begins the process by forecasting customers' electric demand for 20 years. The electric demand forecast considers historical electric demand, economics, weather, appliance efficiency trends (driven by Federal codes and standards), population growth, adoption of customer owned generation (such as solar panels), and Vectren DSM energy efficiency programs (such as appliance rebates). A base, low, and two high peak load forecasts were developed.

The next step in the process is to determine possible alternative futures (scenarios) and determine how to reliably and economically meet customers' future electric demand. Vectren has adequate resource options (power plants, on-going energy efficiency and demand response options) to meet customers' need. The base scenario assumes customer need will be met with existing resources. The second scenario examines the potential impact of retiring FB Culley 2, Vectren's oldest, smallest (83 MW), and most inefficient coal generating unit. Additionally, it is not controlled for NO_x. The final scenario included a possible future where the government enacts a Renewable Portfolio Standard (RPS), requiring 20% of electricity to be produced with renewable resources, such as wind, solar, customer-owned renewable distributed generation, and utility sponsored DSM energy efficiency programs.

Each electric demand forecast is exposed to the base and two alternate futures to determine the most economical way to meet customer needs, resulting in 12 possible plans. The diagram below illustrates each alternative.

		A	B	C
		Base	FB Culley 2 Unit Retirement	RPS
1	Base Demand Forecast	Plan A1	Plan B1	Plan C1
2	Low Demand Forecast	Plan A2	Plan B2	Plan C2
3	High (modeled) Demand Forecast	Plan A3	Plan B3	Plan C3
4	High (large load) Forecast[1]	Plan A4	Plan B4	Plan C4

[1] The base demand forecast with a 100 MW firm load addition in 2018

Each plan represents the lowest-cost option to meet customer demand. Several resource options were considered in the analysis to meet customer demand, including various (types and sizes) natural gas powered generation options, additional energy efficiency programs beyond what is already included in the electric demand forecasts, renewables (wind and solar generation), and short-term market capacity purchases.

All model inputs and assumptions are loaded into a modeling tool called Strategist, which is used by many utilities throughout the country. The modeling tool optimizes for the lowest-cost plan to meet customer demand, plus a 7.3% UCAP planning reserve margin.

Each plan was then subjected to additional risk sensitivities to determine which plan is the lowest cost over a wide range of possible future risks. As previously mentioned, resource modeling requires a large number on inputs and assumptions: forecasts for natural gas prices, coal prices, market energy prices, CO_2 prices, costs of resource options, and potential costs for regulations. If the costs of any of these risk factors vary significantly from the base forecasts, the results of the analysis could potentially be different. Each plan (A1-C4) was subjected to varying costs (most often +/- 20%) for the risk factors mentioned above to determine the impact to each plan from the possible future sensitivities.

The remainder of this IRP is organized as follows:

MISO

Chapter 3 - Discusses Vectren's participation in MISO and the implications for resource planning

Environmental

Chapter 4 - Discusses current and pending environmental issues and regulations and the potential considerations for resource decisions

Forecast

Chapter 5 - Contains the electric sales and demand forecast

Supply-Side

Chapter 6 - Describes the electric supply analysis including a review and screening of the various electric supply options

Chapter 7 - Describes the viability and application of renewable and clean energy technologies and renewable energy credits (RECs)

Chapter 9 - Contains a discussion of Vectren's transmission and distribution expansion plan forecast

Demand-Side

Chapter 8 - Presents a discussion of DSM resources including screening results and program concept development

Integration

Chapter 10 - Details the formal integration process which includes conducting sensitivity analyses and obtaining the final resource plan

Short term Action Plan

Chapter 11 - Contains action plans designed to implement the resource plan over the next three years

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CHAPTER 3

MISO

INTRODUCTION

Vectren was an original signer of the Transmission Owners Agreement, which organized the Midwest Independent Transmission System Operator, now known as the Midcontinent Independent System Operator (MISO) and under which authority the MISO administers its Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff). As a vertically integrated utility with the responsibility and obligation for serving load within the MISO footprint, Vectren has integrated many functions with the operating procedures of MISO. This integration involves the coordinated operation of its transmission system and generating units, and the functions range from owning and operating generation and transmission, to complying with certain reliability standards. These standards include planning and operation of resources to meet the needs of loads in the future and are set by the North American Electric Reliability Corporation (NERC) and the regional reliability entity Reliability First Corporation, both of which are overseen by the Federal Energy Regulatory Commission (FERC).

MISO OVERVIEW

MISO, headquartered in Carmel, Indiana, with additional offices in Egan, Minnesota, was approved as the nation's first regional transmission organization in 2001. Today, MISO manages one of the world's largest energy and operating reserves markets; the market generation capacity was 175,436 MW as of May 1, 2014. This market operates in 15 states and one Canadian province.

Key Dates

- February 1, 2002 - Transmission service began under MISO Open-Access Transmission Tariff with Vectren as a full Transmission Owning Member
- April 1, 2005 - Midwest markets launch
- April 16, 2008 - NERC certified MISO as Balancing Authority
- January 6, 2009 - Ancillary Services Markets began and MISO became the region's Balancing Authority
- December 19, 2013 – Added South Region

Vectren in Relation to MISO Footprint

With a native peak load of about 1,150 MW, Vectren is approximately 1.4% of the MISO market footprint and is one of 36 local balancing authorities. In addition, the Vectren transmission system supports multiple municipals and a large industrial smelter. The total control area or Local Balancing Area (LBA) is approximately 1,900 MW.

Figure 3-1 below is a drawing of the entire MISO market footprint, and Figure 3-2 shows the MISO Reliability Coordination Area.

Figure 3-1 MISO Market Area

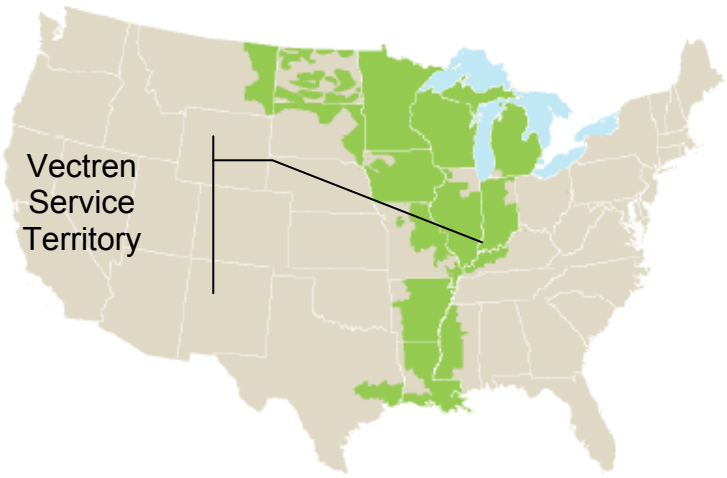
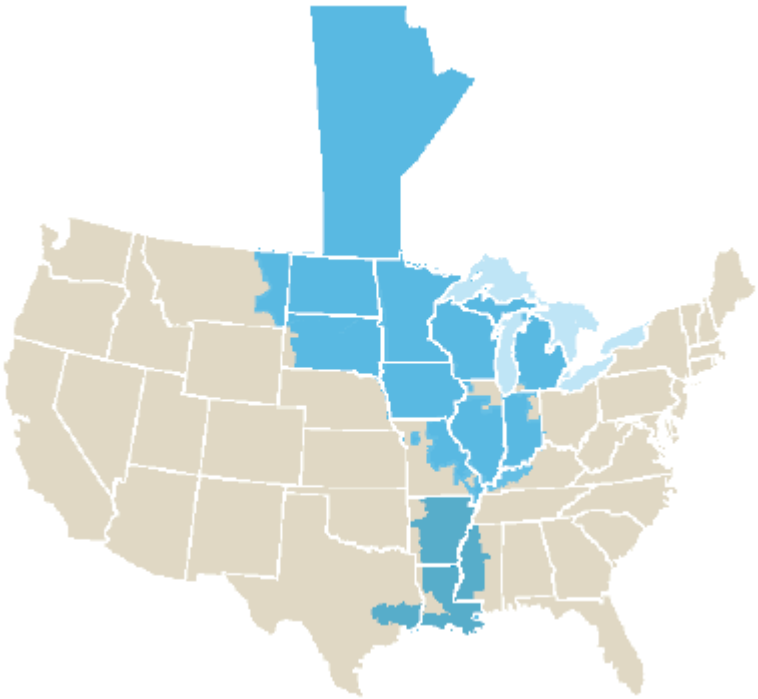


Figure 3-2 MISO Reliability Coordination Area



MISO's GOALS

The goal of MISO's regional transmission planning process is the development of a comprehensive expansion plan that meets both reliability and economic expansion needs. This process identifies solutions for reliability issues that arise from the expected dispatch of network resources. These solutions include evaluating alternative costs between capital expenditures for transmission expansion projects and increased operating expenses from redispatching network resources or other operational actions.

The MISO Board of Directors has adopted six planning principles to guide the MISO regional plan:

1. Make the benefits of an economically efficient energy market available to customers by identifying transmission projects which provide access to electricity at the lowest total electric system costs.
2. Provide a transmission infrastructure that upholds all applicable NERC and Transmission Owner planning criteria and safeguards local and regional reliability through identification of transmission projects to meet those needs.
3. Support state and federal energy policy requirements by planning for access to a changing resource mix.

4. Provide an appropriate cost allocation mechanism that ensures the costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects.
5. Analyze system scenarios and make the results available to state and federal energy policymakers and other stakeholders to provide context and to inform choices they face.
6. Coordinate transmission planning with neighboring planning regions to seek more efficient and cost-effective solutions.[1]

MISO is designated as Vectren's Planning Authority, under the NERC reliability standards, and in FERC Order 1000, MISO has additional regional planning responsibilities.

MISO PLANNING PROCESS

MISO Transmission Planning Process

MISO's transmission planning process begins with the models for the current planning cycle and includes opportunities for stakeholder input on the integration of transmission service requests, generator interconnection requests, and other studies to contribute to the development of an annual MISO Transmission Expansion Plan (MTEP) report.

The 2013 MTEP recommended $1.48 billion in 317 new projects across the MISO footprint through the year 2023. MISO MTEP process has recommended $17.9 billion total investment since its 2003 inception through the first 10 years.

[1] These Guiding Principles were initially adopted by the Board of Directors, pursuant to the recommendation of the System Planning Committee, on August 18, 2005, and reaffirmed by the System Planning Committee in February 2007, August 2009, May 2011, and March 2013.

MISO's role in meeting Vectren's requirements as a member of ReliabilityFirst for a Planning Reserve Margin

As a result of the Energy Policy Act of 2005, regional entities were delegated authority by FERC to establish standards to provide for reliable operation of the bulk-power system. Vectren is a member of regional entity ReliabilityFirst, and so must comply with regional entity Reliability First standards, including the Planning Resource Adequacy Analysis and the Assessment and Documentation Standard BAL-502-RFC-02. This assessment and documentation standard requires planning coordinators to perform annual resource adequacy analyses. This includes calculating a planning reserve margin (PRM) that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year equal to a one day in 10 year criterion. This PRM requirement also includes documenting the projected load, resource capability, and PRM for the years under study, and other particular criteria.

The first planning year the Reliability First Planning Reserve Standard was in effect (June 2008-May 2009), Vectren complied with the ReliabilityFirst Planning Resource Adequacy standard by participating in the Midwest Planning Reserve Sharing Group. The calculated required PRM for Vectren was 14.3% on an installed capacity basis. For planning year June 2009-May 2010 and beyond, Vectren and all other MISO utilities have delegated their tasks assigned to the Load Serving Entities (LSEs) under BAL-502-RFC-02 to MISO. The specific section of the MISO Tariff that addresses planning reserves is Module E-1 Resource Adequacy. Vectren is complying with the ReliabilityFirst Planning Resource Adequacy standard by meeting the MISO Module E individual LSE required PRM. This PRM (UCAP) is 7.3% for planning year June 2014 - May 2015.

MISO's Module E-1

As previously mentioned, Module E-1- Resource Adequacy is the portion of the MISO Tariff which requires MISO to determine the Planning Reserve Margin Requirement, on

an unforced capacity (UCAP) basis, that would result in 1 day in 10 Loss of Load Event reliability standard. Module E-1 and its associated business practice manual lays out the mandatory requirements to ensure access to deliverable, reliable and adequate planning resources to meet peak demand requirements on the transmission system. To perform these calculations, MISO requires entities to utilize their Module E Capacity Tracking Tool (MECT) to submit a forecast of demand and list their qualified resources. This same tool is then leveraged to accept offers into MISO's annual Planning Resource Auction (PRA).

Loss of Load Expectation and Determination of Planning Reserve Margins

MISO used a Loss of Load Expectation[1] (LOLE) of 1 day in 10 years as the probabilistic method to determine expected number of days per year for which available generating capacity is insufficient to serve the daily peak demand (load). This LOLE, along with other LSE-specific data, is used to perform a technical analysis on an annual basis to establish the PRM UCAP for each LSE. The PRM analysis considers other factors such as generator forced outage rates of capacity resources, generator planned outages, expected performance of load modifying resources, forecasting uncertainty, and system operating reserve requirements.

For this year, an unforced capacity planning reserve margin of 7.3% applied to the MISO system Coincident Peak Demand has been established for the planning year of June 2014 through May 2015. This value was determined by MISO through the use of the GE Multi-Area Reliability Simulation (MARS) software for Loss of Load analysis.

Effect of Load Diversity

Within Module E-1, individual LSEs maintain reserves based on their Coincident Peak Demand, which is the LSE's demand at the time of the MISO peak. MISO no longer calculates a Load Diversity Factor for LSE's, as this would be different for each LSE. However, each LSE peaks at a different time, and for reference, an LSE can determine

[1] Included in the Technical Appendix, section I

what the PRM UCAP would be when accounting for load diversity by multiplying the PRM UCAP times the ratio of LSE Coincident Peak Demand divided by LSE peak Demand.

Forecast LSE Requirements

LSEs must demonstrate that sufficient planning resources are allocated to meet the LSE Coincident Peak Demand multiplied by one plus the PRM and one plus transmission losses. The submission of this forecast follows MISO's prescribed processes.

LSEs must report their peak demand forecasts for each month of the next two planning years and for each summer period (May-October) and winter period (November-April) for an additional eight (8) planning years for the NERC MOD standards.

Forecasted demand in MISO reflects the expected "50/50" LSE Coincident Peak Demand and includes the effect of all distribution and transmission losses. This means there is a 50% chance that actual demand will be higher and a 50% chance that actual demand will be lower than the forecasted level.

LSEs must also report their Net Energy for Forecasted Demand for the same time periods: monthly for the next two planning years and for each summer period (May-October) and winter period (November-April) for an additional eight (8) planning years for the NERC MOD standards.

LSEs register demand side management into the MECT tool separate from their demand forecasts. These resources are explicitly modeled on the supply side in determination of the PRM.

Resource Plan Requirements

LSEs are obligated to provide MISO with resource plans demonstrating that Zonal Resource Credits (ZRC) will be available to meet their resource adequacy requirements. Generally, the Planning Reserve Margin Requirement (PRMR) is the forecast LSE Peak Demand multiplied by one plus MISO PRM UCAP and one plus transmission losses, unless the state utility commission establishes a PRM that is different from MISO's. Additionally LSEs must meet a Local Clearing Requirement (LCR) for the Local Resource Zone (LRZ) for which the LSE resides, Vectren is in LRZ six. The LCR is equal to the Local Reliability Requirement (LRR) less the Capacity Import Limit (CIL) into that zone. The LRR is established so that the LRZ can also meet the 1 day in 10 LOLE reliability standard by clearing the necessary resources within the LRZ.

If a state utility commission establishes a minimum PRM for the LSEs under their jurisdiction, that state-set PRM will be adopted by MISO for affected LSEs in such state. If a state utility commission establishes a PRM that is higher than the MISO established PRM, the affected LSE's must meet the state-set PRM.[1] Indiana does not have a stated minimum planning reserve margin; therefore, Vectren must meet the PRM of MISO.

Qualification of Resources, Including Unforced Capacity Ratings (UCAP), Conversion of UCAP MW to Zonal Resource Credits

To comply with MISO Resource Adequacy provisions, LSEs must submit data for their eligible resources for MISO to determine the total installed capacity that the resource can reliably provide, called Unforced Capacity Rating (UCAP).

[1] From MISO BPM-011-r13 Resource Adequacy Section 3.5.5 State Authority to set PRM

MISO will calculate unforced capacity for all generation resources interconnected to the MISO Transmission System while respecting the interconnection study results and the results of the aggregate deliverability analysis.

The first step is to compare a Generation Resource Net Dependable Capacity (NDC) to the tested capacity from the interconnection process to determine the total installed capacity that the generation resource can reliably provide, which is the Total Interconnection Installed Capacity (ICAP). A unit's NDC for the Planning Year is determined by averaging the NDC data that is entered into MISO's Generating Availability Data System (GADS) database. The UCAP rating represents the MW's that are eligible to be converted into ZRCs.

Evaluation and Reporting

MISO will maintain databases and will "..provide to states, upon request, with relevant resource adequacy information as available…" per section 69 of the MISO Tariff during relevant time periods, subject to the data confidentiality provisions in section 38.9 of the MISO Tariff.

Vectren's approach to the Voluntary Capacity Auction

Due to the long lead time generally required to build capacity resources, Vectren does not consider MISO's annual Planning Resource Auction an appropriate means to meet the needs of the 20 year Integrated Resource Plan and continues to pursue more traditional means of ensuring adequate resources.

Future of MISO's Module E

MISO proposed Capacity Market

MISO is currently evaluating whether the annual summer based resource adequacy construct contains gaps that prevent it from achieving resource adequacy during all periods of the year. MISO is working to identify seasonal or other changes that will close any identified gaps.

Footprint Changes

On Dec. 19, 2013 MISO began coordinating all RTO activities in the newly combined footprint consisting of all or parts of 15 states with the integration of the MISO south entities which include the LBAs of Entergy Arkansas, Inc., Entergy Texas, Inc., Entergy Mississippi, Inc., Entergy Louisiana, LLC, Entergy Gulf States Louisiana, L.L.C., Entergy New Orleans, Inc., Cleco Power LLC, Lafayette Utilities System, Louisiana Energy & Power Authority, South Mississippi Electric Power Authority and Louisiana Generating, LLC.

DEMAND RESPONSE

Demand response is an integral part of a utility's system, operations, and planning, and helps Vectren meet the obligation to serve all customers. Effective July 1, 2011 and pursuant to Commission order in Cause 34566 MISO 4, Vectren filed Rider DR, which provides qualifying customers the optional opportunity to reduce their electric costs by participating in the MISO wholesale energy market. This rider helps the Company's efforts to preserve reliable electric service through customer provision of a load reduction during MISO high price periods and declared emergency events. This initial Rider DR offers two programs, Emergency Demand Response (EDR) and Demand Response Resource Type 1 ("DRR-1") energy programs.

MISO FORECAST

Based on analysis of load forecasts and planned resources derived from survey responses provided by the load serving entities in its footprint, MISO has created several iterations of resource adequacy forecasts that indicate beginning in 2016, several zones within the footprint may lack the capacity required to meet reserve requirements. MISO continues to assess the accuracy of this analysis and appears to concede that state regulatory commissions remain confident that adequate reserves exist in the near term. However, such studies do highlight the potential reliability issues created by the EPA emissions restrictions, and in particular, the potential for numerous base load coal plant retirements driven by the EPA's Clean Power Plan. Questions

regarding available capacity, as well as local reliability concerns will be factored into the Company's planning processes.

Vectren's Approach to Resource Adequacy

Vectren will continue to comply with MISO's Module E requirements, which includes the possibility for varying amounts of planning reserves.

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Chapter 4

ENVIRONMENTAL

INTRODUCTION

Compliance planning associated with existing and anticipated environmental laws and regulations in each of the three media (air, water and waste) is discussed in this chapter.

CURRENT ENVIRONMENTAL COMPLIANCE PROGRAMS:

AIR

Acid Rain Program

Vectren's Acid Rain compliance program was approved by the IURC in Cause No. 39347, which authorized the construction of a combined sulfur dioxide (SO_2) scrubber for FB Culley Units 2 and 3. As AB Brown Units 1 and 2 were newer vintage units, the units' original construction included scrubber technology. Vectren relies upon its existing scrubber technology for compliance with acid rain requirements and has sufficient allowance allocations to meet its future acid rain obligations. See, Table 4-1, a listing of current air pollution control devices for each Vectren unit, Table 4-2, a listing of emission rates for each Vectren unit, and Table 4-3 a listing of the acid rain allowances allocated to Vectren units.

Table 4-1 Air Pollution Control Devices Installed

	FB Culley 2	FB Culley 3	Warrick 4	AB Brown 1	AB Brown 2
Commercial Date	1966	1973	1970	1979	1986
MW (UCAP)	83	257	135	228	233
NO_X	Low NO_X Burner	SCR[1]	SCR	SCR	SCR
SO_2	FGD[2]	FGD	FGD	FGD	FGD
PM[3]	ESP[4]	FF[5]	ESP	FF	ESP

[1] Selective Catalytic Reduction
[2] Flue Gas Desulfurization
[3] Particulate Matter
[4] Electrostatic Precipitator
[5] Fabric Filter

Table 4-2 Current (2013) Emission Rates (lbs./mm Btu)

Units	SO_2	Annual NO_X	Ozone Season NO_X
AB Brown 1	0.6400	0.1510	0.1464
AB Brown 2	0.3610	0.1160	0.1091
AB Brown 3	0.0006	0.1800	0.1710
AB Brown 4	0.0006	0.0310	0.0214
FB Culley 2/3	0.1700	0.1190	0.1312
Warrick 4	0.1800	0.2400	0.2740
BAGS 2	0.0006	0.2226	0.2111

Table 4-3 SO2 Acid Rain Allowances Allocated to Vectren Units (per year)

Plant Name	Percent Ownership	2013	2014-2041
AB Brown	100%	10,546	10,546
FB Culley	100%	9,922	9,922
Warrick 4[1]	50%	5,122	5,122

For purposes of compliance year 2014, acid rain allowances will continue to be used for compliance with the SO_2 emission reductions requirements of the Clean Air Interstate Rule (CAIR). As detailed more fully below, the Cross-State Air Pollution Rule (CSAPR) which was originally slated to become effective in two phases during 2012 and 2014, was stayed by the Court in December 2011 and vacated in August 2012. Through a series of appeals, it was reviewed by the US Supreme Court who issued judgment on April 29, 2014 to reverse the lower Court decision and upheld CSAPR. The stay was lifted on October 23, 2014 but an implementation schedule and reallocation of allowances has not been determined at this time. Due to the timing of this recent decision, Vectren is unable to state when CSAPR will go into effect and what the final allowance levels will be for each of its units. Neither the CAIR rule nor CSAPR supersedes the Acid Rain program. Facilities will still be required to annually surrender acid rain allowances to cover emissions of SO_2 under the existing Acid Rain program.

[1] Number of allowances shown are for Vectren's portion of Warrick 4

NO_x SIP Call

Vectren's NO_x SIP Call compliance plan was approved by the IURC in Cause Nos. 41864 and 42248, which authorized Vectren to retrofit selective catalytic reduction (SCR) technology on Culley Unit 3, Warrick Unit 4, and Brown Units 1 and 2. Vectren relies upon its existing SCR technology for compliance with the seasonal NO_x reductions required in the NO_x SIP Call. When CAIR was finalized in March of 2005, the EPA included a seasonal NO_x emission reduction requirement, which incorporated, and in most cases, went beyond the seasonal NO_x emission reductions required under the NO_x SIP Call. For purposes of compliance year 2014, CAIR NO_x seasonal allowances will continue to be used for compliance with the seasonal NO_x emission reductions requirement under the current CAIR rule. CAIR and CSAPR are discussed more fully below.

CAIR and CSAPR

On March 10, 2005, the US Environmental Protection Agency (EPA) finalized its determination in the CAIR rule that emissions from coal-burning Electric Generating Units (EGUs) in certain upwind states result in the transport of fine particles ($PM_{2.5}$) and ozone that significantly contribute to nonattainment of the applicable ambient air quality standards for those pollutants in downwind states. The CAIR rule required revisions to state implementation plans in twenty eight states, including Indiana, requiring further reductions of NO_x and SO_2 from EGUs beyond those required in the NO_x SIP Call and Acid Rain programs. Emissions reductions under the CAIR rule were to be implemented in two phases, with requirements for first phase reductions in 2009 (NO_x) and 2010 (SO_2), and second phase reductions starting in 2015. The Warrick 4 scrubber was constructed to comply with the CAIR regulation and approved in Cause No. 42861. The CAIR rule provided a federal framework for a regional cap and trade system, and those allowances allocated to the Vectren units under the CAIR rule are being used for compliance in 2014 and until the EPA reinstates CSAPR (see below).

On July 6, 2010, the EPA proposed its Clean Air Transport Rule ("Transport Rule") in response to the court's remand of CAIR. In an effort to address the court's finding that CAIR did not adequately ensure attainment of ozone and $PM_{2.5}$ air quality standards in certain Eastern states due to unlimited trading and banking of allowances, the Transport Rule proposal dramatically reduced the ability of facilities to meet the required emission reductions through interstate allowance trading. Like CAIR, the Transport Rule proposal set individual state caps for SO_2 and NO_x; however, unlike CAIR, individual unit allowance allocations were set out directly in the Transport Rule proposal. Interstate allowance trading was severely restricted and limited to trading within a zonal group. On July 7, 2011, the EPA finalized the Transport Rule proposal and renamed the program the Cross State Air Pollution Rule (CSAPR). CSAPR sets individual allowance allocations for Vectren's units directly in the rule. Table 4-4 shows a listing of individual unit allowance allocations under the original CSAPR. Under the original version of CSAPR, any excess CAIR allowances (vintage 2011 or older) that were not needed for compliance in 2011 could not be used for compliance with CSAPR, which was scheduled to become effective January 1, 2012. It is not yet known how, or when, the EPA will revise the effective dates in the reinstated version of the rule. Given the stringent state emission caps, the limited allowance trading available under the CSAPR, and the unknown implementation timing due to the recent lifting of the court ordered stay on October 23, 2014 it is virtually impossible to predict with any certainty the availability of excess allowances for compliance and the costs of those allowances under a reinstated CSAPR.

Table 4-4 CSAPR Allowances Allocated to Vectren Units

	SO_2 Allocation		Annual NO_X		Seasonal NO_X	
	2012	**2014**	**2012**	**2014**	**2012**	**2014**
AB Brown 1	3,761	2,080	1,393	1,376	595	586
AB Brown 2	3,889	2,151	1,440	1,422	601	591
AB Brown 3	1	1	19	19	14	14
AB Brown 4	0	0	6	6	4	4
BAGS 2	0	0	26	26	18	8
FB Culley 2	1,488	925	619	612	268	264
FB Culley 3	2,923	2,799	1,874	1,851	792	780
Warrick 4	2,802	1,550	1,037	1,025	444	437

Vectren's original multi-pollutant compliance plan was approved under IURC Cause No. 42861. While Vectren's original multi-pollutant planning focused on compliance with the CAIR regulation which was in place at the time, the successful execution of the approved multi-pollutant plan would enable Vectren to comply with the SO_2 and NO_x emission caps in the original CSAPR allocation without further significant capital investment; however, while currently well controlled, Vectren will incur increased Operating and Maintenance (O&M) costs attributable to a new regulation, such as an increase in chemical costs to achieve the lower emission targets. With the completion of the Warrick 4 scrubber pursuant to the approved order in Vectren's multi-pollutant proceeding, Vectren's generating system is 100% scrubbed for SO_2 and has selective catalytic reduction technology on all but one unit (FB Culley Unit 2). See Table 4-1. As such, Vectren will be well-positioned to comply with the new, more stringent SO_2 and NO_x caps that are required by a re-instated CSAPR, without reliance on a highly uncertain allowance market or further significant capital expenditures. It is important to note that CSAPR stay was just recently lifted on October 23, 2014, and final implementation dates are still unknown.

Mercury and Air Toxics Rule

The 1990 Amendments to the Clean Air Act (CAA or Act) required that the EPA determine whether EGUs should be required to reduce hazardous air pollutants, including mercury, under § 112 of the Act. In December of 2000, the EPA officially listed coal-fired EGUs as subject to CAA § 112 Maximum Achievable Control Technology (MACT) Standards for mercury, thus lifting a previous exemption from the air toxics requirements. On March 15, 2005, the EPA finalized its Clean Air Mercury Rule (CAMR) which set "standards of performance" under CAA §111 for new and existing coal-fired EGUs and created a nation-wide mercury emission allowance cap and trade system for existing EGUs which sought to reduce utility emissions of mercury in two phases. The first phase cap would have started in 2010, except the CAMR rule was similarly vacated by a reviewing court in March of 2008. Thus, like the CAIR rule, utilities were preparing for compliance with a finalized CAMR regulation that was ultimately found to be deficient by a reviewing court. The reviewing court directed the EPA to proceed with a MACT rulemaking under CAA § 112 which would impose more stringent individual plant-wide limits on mercury emissions and not provide for allowance trading.

On March 16, 2011, the EPA released its proposed MACT for utility boilers. The final rule, known as the Mercury and Air Toxics Standards (MATS) was published in the Federal Register on February 16, 2012. The rule sets plant-wide emission limits for the following hazardous air pollutants (HAPs): mercury, non-mercury HAPs (e.g. arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The EPA established stringent plant-wide mercury emission limits (1.2 lb/TBtu for individual unit or 1.0 lb/TBtu for plant average) and set surrogate limits for non-mercury HAPs (total particulate matter limit of .03 lb/MMBtu) and acid gases (HCL limit of .002 lb/MMBtu). The surrogate limits can be used instead of individual limits for each HAP. Compliance with the new limits will be required by April 16, 2015. The Indiana Department of Environmental Management (IDEM), the state permitting authority, has the discretion to grant a compliance extension of up to

one year on a case by case basis if a source is unable to install emission controls or make fuel conversions prior to the April 2015 deadline. Vectren was granted a 1-year extension for the AB Brown Unit 2, contingent upon the need for injection of a secondary mercury treatment chemical. The need for the secondary chemical will not be known until after the primary system is operational at the end of 2014. Vectren currently has a MATS Compliance plan before the Commission (IURC Cause 44446) for approval that includes organo sulfide injection at the baseload units (AB Brown 1, AB Brown 2, FB Culley 3, and Warrick 4) with the possibility of an additional HBr injection at AB Brown 2 if needed.

SOLID WASTE DISPOSAL

Scrubber by-products from AB Brown are sent to an on-site landfill permitted by IDEM. During the fall of 2009, Vectren finalized construction of a dry fly ash silo and barge loading facility that would allow for the beneficial reuse of Vectren generated fly ash. Since February 2010, the majority of AB Brown fly ash has been diverted to the new dry ash handling system and sent for beneficial reuse to a cement processing plant in St. Genevieve, Missouri, via a river barge loader and conveyor system. The remainder of the A B Brown fly ash and bottom ash is sluiced to an on-site pond. This major sustainability project will serve to mitigate negative impacts from the imposition of a more stringent regulatory scheme for ash disposal. The majority of Vectren's coal combustion materials are now being diverted from the existing ash pond structures and surface coal mine backfill operations and transported offsite for recycling into a cement application.

Fly ash from the FB Culley facility is similarly transported off-site for beneficial reuse in cement. Until mid-2009, fly ash from the FB Culley facility was sent to the Cypress Creek Mine for backfill pursuant to the mine's surface coal mine permit. In May 2009, FB Culley began trucking fly ash to the St. Genevieve cement plant. Upon completion of the barge loading facility at the AB Brown facility in late 2009, FB Culley's fly ash is now transported to the AB Brown loading facility and shipped to the cement plant via

river barge. The FB Culley facility sends its bottom ash to one of two on-site ponds via wet sluicing. The ponds are seven and eighteen acres in size. Scrubber by-product generated by the FB Culley facility is also used for beneficial reuse and shipped by river barge from FB Culley to a wallboard manufacturer. In summary, the majority of Vectren's coal combustion material is no longer handled on site, but is being recycled and shipped off-site for beneficial reuse.

HAZARDOUS WASTE DISPOSAL

Vectren's AB Brown and FB Culley plants are episodic producers of hazardous waste that may include paints, parts washer fluids, or and other excess or outdated chemicals. Both facilities are typically classified as Conditionally Exempt Small Quantity Generators.

WATER

AB Brown and FB Culley currently discharges process and cooling water to the Ohio River under National Pollutant Discharge Elimination System (NPDES) water discharge permits issued by the IDEM. AB Brown utilizes cooling towers while FB Culley has a once through cooling water system.

The Ohio River Valley Sanitation Commission (ORSANCO) regional water quality standards were most recently revised in 2012 and are more restrictive than current EPA standards. ORSANCO is a regional state compact focused on water quality issues for the Ohio River and governs water discharges that enter the Ohio River. Under Vectren's most recent NPDES permits issued in late 2011, Vectren must meet more restrictive mercury limits at its river outfall to comply with the ORSANCO mercury limit of 12 ppt monthly average. To meet the limits, Vectren chose to install two chemical-precipitation water treatment systems at AB Brown and one at FB Culley. The new water treatment systems are included in the pending environmental compliance proceeding before the IURC (Cause No. 44446), and began operation in third quarter 2014.

FUTURE ENVIRONMENTAL REGULATIONS

CARBON REGULATION

On June 2, 2014, the EPA issued the CAA Section 111(d) Greenhouse Gas (GHG) New Source Performance Standards (NSPS) for existing sources, known as the Clean Power Plan (CPP). The CPP sets state-specific carbon reduction goals based on a state's existing generation mix and provides guidelines for the development, submission and implementation of state plans to achieve the state goals. The EPA asserts that the state reduction goals will result in a 30% decrease in CO_2 emissions from 2005 levels by 2030. To insure each state is making adequate progress towards the 2030 goal, an interim emission rate goal for 2020-2029 has also been established.

Indiana's state specific emission rate goals are 1,607 lb CO_2/MWh for the interim period and 1,531 lb CO_2/MWh for a final goal. This equates to a 20% reduction in CO_2 emission rates from 2012 levels. The EPA determined the state specific goals through a portfolio approach that includes improving power plant heat rates, dispatching lower emitting fuel sources more frequently and increasing utilization of renewable energy sources and energy efficiency programs. Specifically, each state's goals were set by taking 2012 emissions data and applying four "building blocks" of emission rate improvements that the EPA has determined are achievable by that state.

The four building blocks used by the EPA to calculate state goals are as follows:

1) Coal fleet heat rate improvement of 6%.
2) Increased dispatch of existing baseload natural gas generation sources to 70%. For Indiana this also includes announced new natural gas combined cycle plants.
3) Renewable energy portfolio of 5% in the interim and 7% in the final stage.
4) Energy efficiency reductions of 1.5% annually starting in 2020.

While individual state goals were based on the EPA's application of the building blocks to 2012 emission rates, states have flexibility through their state implementation plan to

implement the building blocks in part or not at all to reach the listed goal, or enter a regional trading program. Since the state plan may include a variety of options, many of which are outside the fence line and control of a power plant, the interim and final CO_2 emission rates will not necessarily apply to individual generating plants or companies within the state. It is yet to be determined how the CPP will directly affect Vectren's generating units.

The final rule is scheduled for June 2015, with individual state implementation plans due by June 2016. States have the option to seek a one year extension, or up to two years if part of a regional or multi-state plan. After the submittal of the state or regional plan, the first annual reporting begins in 2022. This timeline represents the earliest emission reductions will be required, as it is almost certain that this rule will be heavily litigated. Vectren will continue to work with the state of Indiana to ensure that the State's compliance plan is the least cost to Indiana consumers.

WASTE DISPOSAL

Over the course of the last twenty years the EPA has conducted numerous studies and issued two reports to Congress on the management of coal combustion by-products (primarily fly ash, bottom ash, and scrubber by-product), concluding both times that these materials generally do not exhibit hazardous waste characteristics and can be managed properly under state solid waste regulations. In response to the Tennessee Valley Authority's (TVA's) catastrophic ash pond spill in December of 2008, the EPA revisited its regulatory options for the management of coal combustion by-products. On June 21, 2010, the EPA published three options for a proposed rule covering Coal Combustion Residuals (CCRs). Two options would regulate combustion by-products as solid waste under the Resource Conservation and Recovery Act (RCRA) Subtitle D, with the only significant difference being whether existing ponds are retrofitted or closed within five years, or whether utilities will be permitted to continue to use an existing pond for its remaining useful life. The third option would regulate combustion by-products as hazardous waste under RCRA Subtitle C. Under all three options, certain beneficial re-

uses of coal combustion residuals, such as cement and wallboard applications, will continue to be allowed. The EPA has set December 19, 2014 as the deadline for issuing the final rule.

Uncertainties remain until the rule is finalized. For example, under the Subtitle D proposed rule, unlined ash ponds would have to be closed within five years and groundwater monitoring installed within one year. The proposal, however, did not define whether the term “close” means to cease receiving new material or to have the site completely capped and grass covered within five years. The proposal also failed to take into account site specific circumstances such as size of the pond and the percentage filled when establishing the five year closure timeframe. A majority of the final closure obligation and compliance costs will be focused on historic material that is already in the ponds so a change in future generation will not negate the obligation to comply with the CCR regulation when it is issued. However, as a result of Vectren’s previous investments in dry fly ash handling and beneficial reuse activities, the volume of new material added to the ponds since 2009 has been significantly decreased.

As a direct result of the TVA spill referenced above, the EPA undertook to inspect all surface impoundments and dams holding combustion by-products. The EPA conducted site assessments at Vectren's AB Brown and FB Culley facilities and found the facilities' surface impoundments to be satisfactory and not posing a high hazard.

WATER

There are multiple regulatory rulemakings that could, when finalized, require more stringent limits for power plant discharges.

The EPA is developing new Effluent Limit Guidelines and Standards (ELGS) for the Steam Electric Power Generating Point Source Category. A draft was issued June 7, 2013, with a final rule scheduled for September 2015. The draft rule requested comment on 8 different options for treatment standards and compliance locations that ranged from no change of

current standards to a requirement for full zero liquid discharge. Of the eight options, the EPA identified four "preferred" options. For the preferred options, the size of Vectren's units would drop the plants out of the requirement for specific treatment and discharge limits for Flue Gas Desulfurization (FGD) waste water or bottom ash transport water in 2 of the 4 options. Instead, IDEM would apply Best Professional Judgment (BPJ) which takes into consideration site specific factors. While Vectren acknowledges that the EPA's final ELGs could further alter discharge parameters and limits, it is not possible at this time to predict the outcome of the final rule. Vectren believes its chosen treatment systems are the most cost effective option for meeting its current permits while limiting potential stranded costs when new regulations take effect.

The EPA released its final rule regulating cooling water structures under Section 316(b) of the Clean Water Act (CWA) on August 15, 2014. Section 316(b) requires that intake structures that withdraw > 2 MGD of water, including most electric generating units, use the "Best Technology Available" to prevent and / or mitigate adverse environmental impacts to shellfish, fish, and wildlife in a water body. The rule lists separate sampling and study programs to minimize entrainment (pulling small organisms into the intake structure) and impingement (trapping or pinning fish against the exterior of the intake structure). In addition, three additional studies are required that look at technical feasibility and treatment costs, cost benefits evaluation, and non-water quality environmental impacts of the potential treatment option. These studies, combined with the results of the in-river fish sampling will help determine potential treatment options.

Seven options were identified as pre-approved methods for complying with impingement mortality standards. While cooling towers are listed as an option, they are not mandated for existing facilities. Vectren does not believe cooling tower retrofits will be required at FB Culley due to its size and location on the Ohio River. The EPA acknowledges that for many facilities, the process of conducting the studies, determining the best treatment option, constructing the selected option, and confirming the adequacy of the treatment may take a minimum of 8 years from the time the rule

becomes effective. Vectren's FB Culley units currently use a "once through" cooling water intake system and are affected by this proposed regulation. Vectren's AB Brown units use a closed cooling water system. However, under the final rule Vectren would still be required to submit documentation and study reports to confirm the existing cooling water tower mitigates impingement and entrainment.

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CHAPTER 5

SALES & DEMAND FORECAST

INTRODUCTION

The electric energy and demand forecasts provide the basis for evaluation of supply-side and demand-side options to meet the electric needs of Vectren's customers. These forecasts reflect local and regional economic impacts, the effects of past, present, and proposed Demand Side Management / Demand Response (DSM/DR) programs, mandated efficiency standards, and the effects of normal market forces on electricity sales.

Overview of Vectren's Customers

Vectren provides delivery services to approximately 142,000 electric residential, general service (commercial), and large (primarily industrial) customers with electricity in southwestern Indiana. A high proportion of Vectren's sales are made to electric-intensive general service and large customers. In 2013, about 29% of Vectren's annual retail electric energy sales were consumed by residential customers, 23% of sales were consumed by General Service (GS), and 48% of sales were consumed by more than 100 large customers. Less than 1% served other load (street lights). Significant general service and large load creates complexity in load forecasting. These customers have the ability to significantly impact Vectren's demand for electricity, as economic factors affect their businesses' success.

ELECTRIC LOAD FORECAST OVERVIEW

Vectren developed low, base, and high forecasts of annual energy sales and requirements (e.g. sales plus related delivery losses) and peak loads (e.g. demand plus losses) for the purposes of its IRP. These forecasts, and the activities undertaken to develop them, are described in this section.

Development of the Vectren system-wide long-term electric load forecast involves the aggregation of multiple models. Vectren uses statistically adjusted end use (SAE) modeling and econometric modeling to forecast customer needs for the future. Vectren has investigated the use of pure end-use modeling for forecasting purposes but

believes that a combination of statistically adjusted end-use and econometric modeling best accommodates its forecasting needs. End-use modeling involves building and maintaining a detailed end-use database to capture appliance and thermal shell characteristics, as well as end-use consumption information. The basic structure of an end-use model is households multiplied by appliance saturation and unit energy consumption. Each component of the end-use model is modeled separately. For these reasons, end-use modeling is very expensive to develop and maintain. It is meant primarily for long-term modeling (5-20 years). Often, a separate short term forecast is necessary, which is hard to integrate with the long-term forecast. Vectren utilizes statistically adjusted end-use models to forecast residential and general service loads. Large customer needs are forecasted with an econometric linear regression model, while street lighting load is forecasted with a simple trend model. The detail of Vectren's forecasting methodology is discussed later in this chapter.

FORECAST RESULTS

The base case forecasts of annual energy requirements and peak loads for the 2014 - 2034 planning period are provided in Tables 5-1 and 5-2. Annual energy requirements are projected to have a -.2% compound annual growth rate over the twenty year planning period. Peak requirements are projected to have a compound annual growth rate of -.1% over the twenty year planning period.

Table 5-1 Base Case Energy and Demand Forecast

Year	Peak (MW)[1]	Annual Energy (GWh)
2014 Proj.	1,145	5,782
2015	1,155	5,914
2016	1,156	5,936
2017	1,113	5,514
2018	1,109	5,503
2019	1,106	5,494
2020	1,106	5,497
2021	1,106	5,492
2022	1,107	5,494
2023	1,107	5,494
2024	1,107	5,496
2025	1,106	5,487
2026	1,106	5,487
2027	1,107	5,492
2028	1,109	5,507
2029	1,110	5,509
2030	1,111	5,517
2031	1,111	5,523
2032	1,113	5,540
2033	1,114	5,548
2034	1,115	5,560
Compound Annual Growth Rate, 2014-2034 Including Wholesale	-0.1%	-0.2%

[1] Includes wholesale contract sales for 2014

Table 5-2 Base Case Energy Forecast by Customer Class

Year	Residential (GWh)	General Service (GWh)	Large (GWh)	Other (GWh)	Net DSM (GWh)	DG (GWh)	Wholesale (GWh)	Losses (GWh)	Total Requirements (GWh)
2013 Calendar	1,435	1,294	2,744	21			61	267	5,822
2014 Proj.	1,444	1,300	2,739	20	(47)	(1)	61	265	5,782
2015	1,444	1,327	2,926	20	(72)	(1)	0	271	5,914
2016	1,448	1,351	2,945	20	(98)	(2)	0	272	5,936
2017	1,451	1,354	2,563	19	(123)	(3)	0	253	5,514
2018	1,458	1,357	2,567	19	(148)	(3)	0	252	5,503
2019	1,469	1,363	2,569	19	(173)	(5)	0	252	5,494
2020	1,475	1,370	2,574	19	(186)	(7)	0	252	5,497
2021	1,480	1,373	2,577	19	(199)	(9)	0	252	5,492
2022	1,490	1,380	2,579	19	(211)	(12)	0	252	5,494
2023	1,500	1,386	2,579	18	(224)	(17)	0	252	5,494
2024	1,514	1,395	2,578	18	(237)	(23)	0	252	5,496
2025	1,523	1,398	2,579	18	(250)	(32)	0	251	5,487
2026	1,534	1,404	2,579	18	(263)	(37)	0	251	5,487
2027	1,547	1,413	2,581	18	(276)	(42)	0	252	5,492
2028	1,562	1,427	2,584	18	(289)	(48)	0	252	5,507
2029	1,572	1,436	2,588	18	(302)	(55)	0	252	5,509
2030	1,586	1,445	2,593	18	(316)	(62)	0	253	5,517
2031	1,599	1,455	2,598	18	(329)	(71)	0	253	5,523
2032	1,616	1,473	2,604	18	(343)	(81)	0	254	5,540
2033	1,628	1,486	2,611	18	(356)	(93)	0	254	5,548
2034	1,644	1,501	2,619	18	(370)	(106)	0	255	5,560
Compound Annual Growth Rate for (2014-2034)	0.6%	0.7%	-0.2%	-0.7%					-0.2%

Low and high energy and demand forecasts were developed by modifying the assumptions around conservation, distributed generation adoption, economic drivers, population projections, and large customer additions. The difference between the two high growth cases is slow steady growth or a large step up. In the high growth (modeled) forecast, economic growth was increased from approximately 1% to 2%, and population growth was increased from about .3% to .5%. The high growth (large load) case is the same as the base case, with the addition of a large customer in 2018. The results are shown in Table 5-3 and 5-4.

Table 5-3 Base, Low, and High Case Energy Forecasts

Year	Base Annual Requirements		Low Growth Annual Requirements		High Growth (modeled) Annual Requirements		High Growth (large load) Annual Requirements	
	GWh	Growth,%	GWh	Growth,%	GWh	Growth,%	GWh	Growth,%
2014 Proj.	5,782		5,782		5,799		5,782	
2015	5,914	2.3%	5,907	2.2%	5,947	2.6%	5,914	2.3%
2016	5,936	0.4%	5,922	0.3%	5,990	0.7%	5,936	0.4%
2017	5,514	-7.1%	5,320	-10.2%	5,609	-6.4%	5,514	-7.1%
2018	5,503	-0.2%	5,302	-0.3%	5,645	0.6%	6,098	10.6%
2019	5,494	-0.2%	5,287	-0.3%	5,681	0.6%	6,088	-0.2%
2020	5,497	0.1%	5,290	0.1%	5,712	0.5%	6,090	0.0%
2021	5,492	-0.1%	5,285	-0.1%	5,734	0.4%	6,085	-0.1%
2022	5,494	0.0%	5,286	0.0%	5,764	0.5%	6,087	0.0%
2023	5,494	0.0%	5,284	0.0%	5,799	0.6%	6,085	0.0%
2024	5,496	0.1%	5,285	0.0%	5,841	0.7%	6,088	0.0%
2025	5,487	-0.2%	5,273	-0.2%	5,870	0.5%	6,077	-0.2%
2026	5,487	0.0%	5,272	0.0%	5,909	0.7%	6,077	0.0%
2027	5,492	0.1%	5,276	0.1%	5,950	0.7%	6,081	0.1%
2028	5,507	0.3%	5,288	0.2%	5,997	0.8%	6,095	0.2%
2029	5,509	0.1%	5,289	0.0%	6,028	0.5%	6,097	0.0%
2030	5,517	0.1%	5,293	0.1%	6,060	0.5%	6,104	0.1%
2031	5,523	0.1%	5,296	0.0%	6,094	0.6%	6,109	0.1%
2032	5,540	0.3%	5,310	0.3%	6,132	0.6%	6,127	0.3%
2033	5,548	0.1%	5,312	0.0%	6,157	0.4%	6,133	0.1%
2034	5,560	0.2%	5,320	0.1%	6,188	0.5%	6,145	0.2%
Compound Annual Growth Rate for (2014-2034)		-0.2%		-0.4%		0.3%		0.3%

Table 5-4 Base, Low, and High Case Demand Forecasts

Year	Base Annual Requirements		Low Growth Annual Requirements		High Growth (modeled) Annual Requirements		High Growth (large load) Annual Requirements	
	MW	Growth,%	MW	Growth,%	MW	Growth,%	MW	Growth,%
2014 Proj.	1,145		1,145		1,148		1,145	
2015	1,155	0.8%	1,153	0.7%	1,160	1.0%	1,155	0.8%
2016	1,156	0.1%	1,153	-0.1%	1,164	0.3%	1,156	0.1%
2017	1,113	-3.7%	1,088	-5.6%	1,127	-3.2%	1,113	-3.7%
2018	1,109	-0.3%	1,083	-0.5%	1,130	0.3%	1,208	8.6%
2019	1,106	-0.3%	1,079	-0.4%	1,133	0.3%	1,205	-0.3%
2020	1,106	0.0%	1,079	0.0%	1,136	0.3%	1,206	0.0%
2021	1,106	0.0%	1,079	0.0%	1,139	0.3%	1,206	0.0%
2022	1,107	0.1%	1,080	0.0%	1,143	0.3%	1,206	0.0%
2023	1,107	0.0%	1,079	0.0%	1,147	0.4%	1,206	0.0%
2024	1,107	0.0%	1,079	0.0%	1,152	0.4%	1,206	0.0%
2025	1,106	-0.1%	1,077	-0.2%	1,155	0.3%	1,205	-0.1%
2026	1,106	0.0%	1,077	0.0%	1,160	0.4%	1,205	0.0%
2027	1,107	0.1%	1,078	0.1%	1,165	0.4%	1,206	0.1%
2028	1,109	0.2%	1,079	0.1%	1,171	0.5%	1,207	0.1%
2029	1,110	0.1%	1,079	0.0%	1,175	0.3%	1,208	0.0%
2030	1,111	0.1%	1,080	0.0%	1,179	0.3%	1,209	0.1%
2031	1,111	0.0%	1,080	0.0%	1,183	0.3%	1,209	0.0%
2032	1,113	0.2%	1,081	0.1%	1,187	0.4%	1,211	0.1%
2033	1,114	0.1%	1,081	0.0%	1,190	0.2%	1,211	0.1%
2034	1,115	0.1%	1,081	0.0%	1,193	0.3%	1,212	0.1%
Compound Annual Growth Rate for (2014-2034)		-0.1%		-0.3%		0.2%		0.3%

FORECAST INPUTS & METHODOLOGY

Forecast Inputs

Energy Data

Historical Vectren sales and revenues data were obtained through an internal database. The internal database 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 exported out of the database and compiled in a spreadsheet on a monthly basis. The data was then organized by rate code and imported into the load forecasting software.

Economic and Demographic Data

Economic and demographic data was provided by Moody's Economy.com for the nation, the state of Indiana, and the Evansville Metropolitan Statistical Area (MSA). Moody's Economy.com, a division of Moody's Analytics, is a trusted source for economic data that is commonly utilized by utilities for forecasting electric sales. The monthly data provided to Vectren 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, GS, and large sales.

Weather Data

The daily maximum and minimum temperatures for Evansville, IN were obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. NOAA data is used to calculate monthly heating degree days (HDD) and cooling degree days (CDD). HDDs are defined as the number of degrees below the base temperature of 65 degrees Fahrenheit for a given day. CDDs are defined as the number of degrees above the base temperature of 65 degrees Fahrenheit for a given day. HDDs and CDDs are averaged on a monthly basis. Normal degree days, as obtained from NOAA,

are based on a thirty year period. Historical weather data[1] 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.

Equipment Efficiencies and Market Shares Data

Itron Inc. provides regional Energy Information Administration (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. Note that in 2013 an appliance survey of Vectren's residential customers was conducted to compare its territory market share data with the regional EIA data. In order to increase the accuracy of the residential average use model, regional equipment market shares were altered to reflect those of Vectren's actual territory.

Model Overview

Changes in economic conditions, prices, weather conditions, as well as appliance saturation and efficiency trends drive energy deliveries and demand through a set of monthly customer class sales forecast models. Monthly regression models are estimated for each of the following primary revenue classes:

- Residential (residential average usage and customer models)
- General Service
- Large
- Street Lighting

In the long-term, both economics and structural changes drive energy and demand growth. Structural changes are captured in the residential average use and general service sales forecast models through Statistically Adjusted End-Use (SAE) model specifications. The SAE model variables explicitly incorporate end-use saturation and

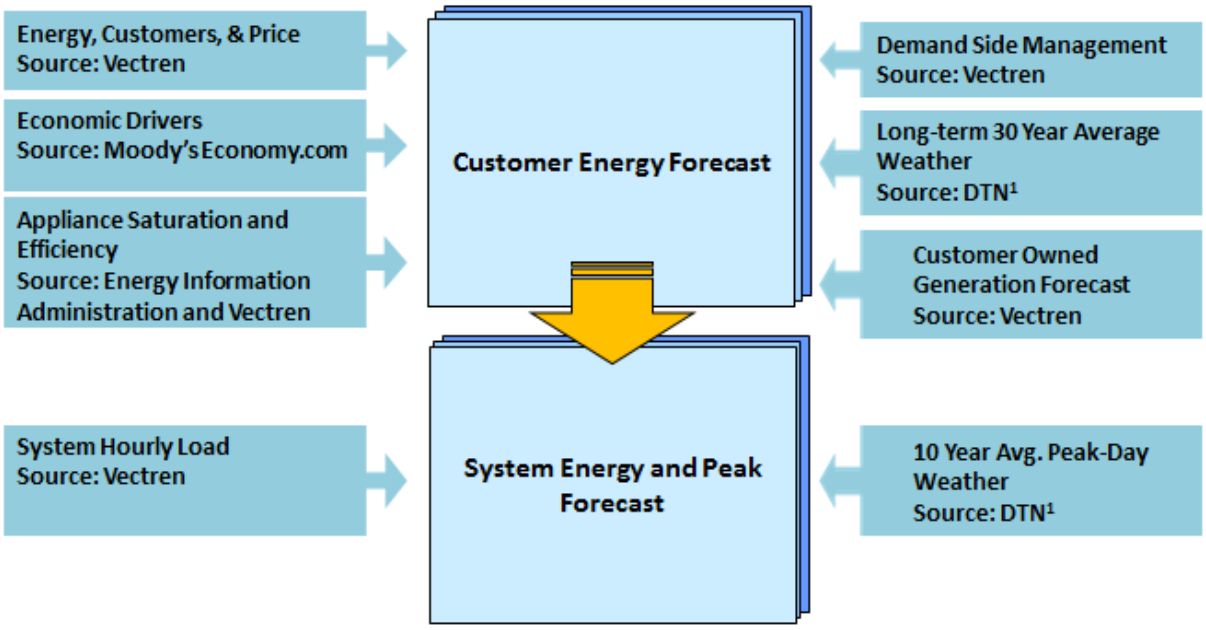
[1] The large sales model also includes CDDs.

efficiency projections, as well as changes in population, economic conditions, price, and weather. End-use efficiency projections include the expected impact of new end-use standards and naturally occurring efficiency gains. The large sales forecast is derived using an econometric model that relates large sales mostly to regional manufacturing Gross Domestic Product (GDP) growth. Street light sales are forecasted using a simple trend and seasonal model. The results of the sales forecast modes are imported into the demand forecast model.

The long-term demand forecast is developed using a "build-up" approach. This approach entails first estimating class and end-use energy requirements and then using class and end-use sales projections to drive system peak demand. The forecast models capture not only economic activity and population projections, but also expected weather conditions, the impact of improving end-use efficiency and standards, and electricity prices.

The long-term system peak forecast is derived through a monthly peak linear regression model that relates monthly peak demand to heating, cooling, and base load requirements. The model variables incorporate changes in heating, cooling, and base-use energy requirements derived from the class sales forecast models as well as peak-day weather conditions. Note that the forecast is adjusted to reflect future Vectren sponsored DSM impacts, expected adoption of customer owned distributed generation, and expected large customer additions. Figure 5-1 shows the general approach.

Figure 5-1: Forecast Approach



[1] Formerly Data Transmission Network, now known as DTN

Analytic Methodology Used in Forecast

Residential Average Use Model

Residential customer usage is a product of heating, cooling, and other load. Both heating and cooling are weather sensitive and must be weather normalized in a model to remove weather noise from projections. Other major drivers of load are historical and projected market saturation of electronics, appliances, and equipment and their respective efficiencies. Vectren's service territory has a high saturation rate of central air conditioning equipment that is growing at a very slow pace, which helps to minimize average use growth. As equipment wears out and is replaced with newer, more efficient equipment, the average energy use per customer (AUPC) is reduced. Although there is increasing use of household electronics and appliances, this is balanced by increasing efficiencies in these areas. High tech devices like televisions, computers, and set-top boxes will see improving efficiencies, driven by innovation, competition, and voluntary agreements like the Energy Star program. Changes in lighting standards are having a large impact on energy consumption and will continue to impact residential customer usage in the years to come.

Even before Vectren sponsored DSM program savings, use per customer is largely flat, increasing only by 0.2% annually through 2024. This is largely due to the continuing phase-out of the most common types of incandescent light bulbs mandated by the Energy Independence and Security Act (EISA) and new end-use efficiency standards recently put in place by the Department of Energy (DOE). Average use begins to increase at a slightly faster rate in the later years, as the Energy Information Administration (EIA) baseline intensity projections only include those end-use standards that are currently law. Note that DOE continues to propose new energy efficiency standards.

The price of electricity and household income also influence average customer energy use. In general, there is a positive correlation between household income and usage. As household income rises, total usage rises. Conversely, there is a negative correlation between price and usage. As price goes up, average use goes down. Finally, the size of the home (number of inhabitants and square footage) and the thermal integrity of the structure affect residential consumption.

The residential average use model is a statistically adjusted end-use (SAE) model that addresses each of the previously discussed drivers of residential usage. SAE models incorporate many of the benefits of econometric models and traditional end-use models, while minimizing the disadvantages of each.

SAE models are ideal for identifying sales trends for short-term and long-term forecasting. They capture a wide variety of relevant data, including economic trends, equipment saturations and efficiencies, weather, and housing characteristics. Additionally, SAE models are cost effective and are easy to maintain and update. In the SAE model, use is defined by three primary end uses: heating (XHeat), cooling (XCool), and other (XOther). XHeat, XCool, and XOther are explanatory variables in the model

that explain customer usage. By design, the SAE model calibrates results into actual sales.

$$ResAvgUse_m = B_0 + (B_1 \times XHeat_m) + (B_2 \times XCool_m) + (B_3 \times XOther_m) + \varepsilon_m$$

The end-use variables incorporate both a variable that captures short-term utilization (Use) and a variable that captures changes in end-use efficiency and saturation trends (Index). The heating variable is calculated as:

$$XHeat = HeatUse \times HeatIndex$$

Where

$$HeatUse = f(HDD, Household\ Income, Household\ Size, Price)$$

$$HeatIndex = g(Heating\ Saturation, Efficiency, Shell\ Integrity, Square\ Footage)$$

The cooling variable is defined as:

$$XCool = CoolUse \times CoolIndex$$

Where

$$CoolUse = f(CDD, Household\ Income, Household\ Size, Price)$$

$$CoolIndex = g(Cooling\ Saturation, Efficiency, Shell\ Integrity, Square\ Footage)$$

XOther captures non-weather sensitive end-uses:

$$XOther = OtherUse \times OtherIndex$$

Where

$$OtherUse = f(Seasonal\ Use\ Pattern, Household\ Income, Household\ Size, Price)$$

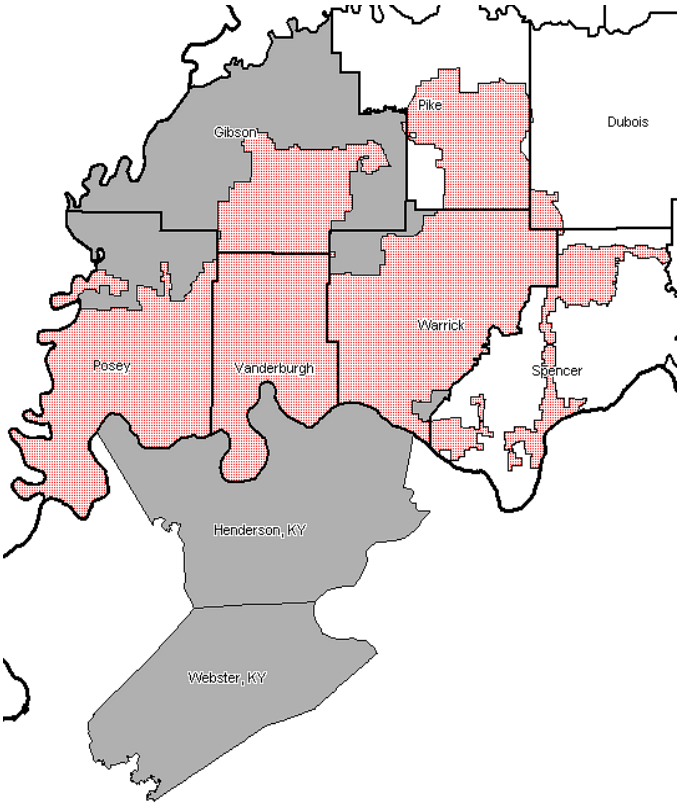
$$OtherIndex = g(Other\ Appliance\ Saturation\ and\ Efficiency\ Trends)$$

Monthly residential usage was regressed on the XHeat, XCool, and XOther variables. The average use model is estimated over the period January 2003 through December 2013. The model explains historical average use well with an Adjusted R^2 of 0.95 and in-sample MAPE of 3.3%.

Residential Customers Model

A simple linear regression model was used to predict the number of residential customers. The number of residential customers was forecasted as a function of population projections for the Evansville Metropolitan Statistical Area (MSA) from Moody's Economy.com. There is a strong correlation between the number of customers and population.

Figure 5-2 Vectren Service Territory Map



The Evansville MSA is a good proxy for the Vectren service territory. Figure 5-2 shows Vectren's service territory (in red) and the Evansville MSA in gray. The number of residential customers is projected to grow an average of .27% per year throughout the planning period. The adjusted R^2 for this model was .992, while the MAPE was .09%.

General Service (GS) Sales Model

Like the residential model, the general service (commercial) SAE sales model expresses monthly sales as a function of XHeat, XCool, and XOther. The end-use variables are constructed by interacting annual end-use intensity projections (EI) that capture end-use efficiency improvements, with non-manufacturing output (GDP) and employment (ComVarm), real price (Pricem), and monthly HDD and CDD:

$$XHeat_m = EI_{heat} \times Price_m^{-0.10} \times ComVar_m \times HDD_m$$
$$XCool_m = EI_{cool} \times Price_m^{-0.10} \times ComVar_m \times CDD_m$$
$$XOther_m = EI_{other} \times Price_m^{-0.10} \times ComVar_m$$

The coefficients on price are imposed short-term price elasticities. A monthly forecast sales model is then estimated as:

$$ComSales_m = B_0 + B_1 XHeat_m + B_2 XCool_m + B_3 XOther_m + e_m$$

Commercial Economic Driver

Output and employment are combined through a weighted economic variable where ComVar is defined as:

$$ComVar_m = (ComEmploy_m^{0.5}) \times (ComOutput_m^{0.5})$$

Employment and nonmanufacturing output are weighted equally. The weights were determined by evaluating the in-sample and out-of-sample model statistics for different sets of employment and output weights.

The resulting commercial sales model performs well with an Adjusted R^2 of 0.95 and an in-sample MAPE of 2.2%.

Commercial sales growth averages 1.9% per year through 2016, as economic growth projections are relatively strong through this period. Real output is projected to increase at 2.2% with employment increasing 1.9%. After 2016, both output and employment growth slow with output averaging 0.5% growth and employment largely flat through 2024. Commercial sales, in turn, slow averaging 0.4% annually between 2016 and 2024.

Large Sales Model

The industrial sales forecast is based on a generalized monthly regression model where industrial sales are specified as a function of manufacturing employment, output, monthly CDD, and monthly binaries to capture seasonal load variation and shifts in the data. The economic driver is a weighted combination of real manufacturing output and manufacturing employment. The industrial economic (IndVar) variable is defined as:

$$IndVar_m = (ManufEmploy_m^{0.3}) \times (ManufOutput_m^{0.7})$$

The imposed weights are determined by evaluating in-sample and out-of-sample statistics for alternative weighting schemes. The final model's Adjusted R^2 is 0.65 with in-sample MAPE of 6.7%. The relatively low Adjusted R^2 and relatively high MAPE are due to the "noisy" nature of industrial monthly billing data.

There are many variables that impact large customer consumption that are not easily forecasted. These unforeseeable impacts make forecasting GS and large customers' usage with a high degree of certainty very difficult, as these customers' usage is extremely sensitive to economic conditions.

Lighting Sales Model

Street light sales are fitted with a simple seasonal exponential smoothing model with a trend term. Street lighting sales have been declining and are expected to continue to

decline through the forecast period as increasing lamp efficiency outpaces installation of new street lights. The model yielded an adjusted R^2 of .769 and a MAPE of 5.34%.

Vectren's total energy requirements include forecasted sales for the four sectors described above, wholesale contracts, DSM savings, impact of customer owned distributed generation (DG) and delivery losses. Losses were estimated to be approximately 4.8 percent of requirements. DSM savings and a forecast of customer owned DG are highlighted separately in the sales forecast, and the DSM programs are discussed in detail in Chapter 8 DSM Resources.

Peak Demand Forecast

The Vectren energy forecast is derived directly from the sales forecast by applying a monthly energy adjustment factor to the monthly calendarized sales forecast. The energy adjustment factor includes line losses and any differences in timing between monthly sales estimates and delivered energy (unaccounted for energy). Monthly adjustment factors are calculated as the average monthly ratio of energy to sales.

The long-term system peak forecast is derived through a monthly peak linear regression model that relates monthly peak demand to heating, cooling, and base load requirements:

$$Peak_m = B_0 + B_1 HeatVar_m + B_2 CoolVar_m + B_3 BaseVar_m + e_m$$

The model variables (HeatVarm, CoolVarm, and BaseVarm) incorporate changes in heating, cooling, and base-use energy requirements derived from the class sales forecast models, as well as peak-day weather conditions.

Heating and Cooling Model Variables

Heating and cooling requirements are driven by customer growth, economic activity, changes in end-use saturation, and improving end-use efficiency. These factors are

captured in the class sales forecast models. The composition of the models allows historical and forecasted heating and cooling load requirement to be estimated.

The estimated model coefficients for the heating (XHeat) and cooling variables (XCool) combined with heating and cooling variable for normal weather conditions (NrmXHeat and NrmXCool) gives an estimate of the monthly heating and cooling load requirements. Heating requirements are calculated as:

$$HeatLoad_m = B_1 \times ResNrmXHeat_m + C_1 \times ComNrmXheat_m$$

B1 and C1 are the coefficients on XHeat in the residential and commercial models.

Cooling requirements are estimated in a similar manner. As there is a small amount of cooling in the industrial sector, industrial cooling is included by multiplying the industrial model coefficient for the CDD variable by normal monthly CDD. Cooling requirements are calculated as:

$$CoolLoad_m = B_2 \times ResNrmXCool_m \mid C_2 \times ComNrmXCool_m \mid D_2 \times NrmCDD_m$$

B2 and C2 are the coefficients on XCool in the residential and commercial models and D2 is the coefficient on CDD in the industrial sales model.

The impact of peak-day weather conditions is captured by interacting peak-day HDD and CDD with monthly heating and cooling load requirements indexed to a base year (2005). The peak model heating and cooling variables are calculated as:

$$HeatVar_m = HeatLoadIdx_m \times PkHDD_m$$
$$CoolVar_m = CoolLoadIdx_m \times PkCDD_m$$

Base Load Variable

The peak model base load variable (BaseVarm) derived from the sales forecast models is an estimate of the non-weather sensitive load at the time of the monthly system peak demand. The base load variable is defined as:

$$BaseVar_m = ResOtherCP_m \times ComOtherCP_m \mid IndOtherCP_m \mid StLightingCP_m$$

Base load requirements are derived for each revenue class by subtracting out heating and cooling load requirements from total load requirements. Using the SAE modeling framework, class annual base load requirements are then allocated to end-uses at the time of monthly peak demand. For example, the residential water heating coincident peak load estimate is derived as:

$$ResWaterCP_m = ResBaseLoad_m \times \left({ResWaterEI_a}/{ResBaseEI_a} \right) \times ResWaterFrac_m$$

Where

ResWaterEI = Annual water heating intensity (water use per household)
ResBaseEI = Annual base-use intensity (non-weather sensitive use per household)
ResWaterFrac = Monthly fraction of usage on at peak (estimates are based on Itron's hourly end-use load profile database)

End-use load estimates are aggregated by end-use and then revenue class resulting in the base load variable.

Model Results

The model explains monthly peak variation well with an adjusted R^2 of 0.97 and an in-sample MAPE of 2.5%.

CUSTOMER OWNED DISTRIBUTED GENERATION FORECAST

Vectren has been monitoring national and regional distributed generation trends since the 2011 IRP. While a number of technologies continue to influence the electric utility industry, the primary focus is on distributed solar. The present IRP considers the potential for future customer-owned DG growth, specifically in the area of net metered distributed solar photovoltaic (PV) adoption. For modeling purposes, distributed PV is treated as a decrease in demand. A distributed solar forecast was developed using Vectren and Indiana historical net metering information and 3rd party data and assumptions. This forecast is presented below in Table 5-5.

Table 5-5 Distributed Solar Growth Forecast

Year Ending	Historic Peak Planning Capacity (MW)	Distributed Solar Adoption Forecasts: Contribution to Peak Planning Capacity[1] (MW)		
		LOW CASE	HIGH CASE	BASE CASE
2006	0.002			
2007	0.002			
2008	0.003			
2009	0.012			
2010	0.029			
2011	0.051			
2012	0.106			
2013	0.162			
2014		0.2	0.2	0.2
2015		0.3	0.3	0.3
2016		0.4	0.4	0.4
2017		0.5	0.6	0.6
2018		0.7	0.9	0.8
2019		0.9	1.2	1.1
2020		1.3	1.7	1.5
2021		1.7	2.4	2.0
2022		2.3	3.3	2.8
2023		3.0	4.7	3.9
2024		4.1	6.6	5.3
2025		5.5	9.2	7.3
2026		6.2	10.6	8.4
2027		7.0	12.1	9.6
2028		7.8	14.0	10.9
2029		8.9	16.1	12.5
2030		10.0	18.5	14.2
2031		11.3	21.2	16.3
2032		12.7	24.4	18.6
2033		14.3	28.1	21.2
2034		16.2	32.3	24.2

[1] Peak planning capacity is 38% of installed capacity.

Because the IRP is concerned with meeting the annual peak demand, the data presented in Table 5-5 are expressed in terms of megawatts of peak planning capacity, rather than total direct current (DC) gross capacity or total alternating current (AC) inverter capacity. The summer peak typically occurs in late afternoon in mid-to-late summer, whereas maximum solar output is generally at noon in late spring or early summer. Because optimal solar output does not coincide with the summer peak, a factor must be applied to estimate the useful solar capacity from a given PV system at the summer peak. A wide range of peak planning capacity factors have been reported for distributed solar resources.[1] Although MISO has not formally adopted a peak planning capacity factor, PJM, a regional transmission operator, has recommended a factor of 38%.[2] Because of this PJM reference, Vectren has chosen to use this value. There may be further refinements on this going forward as the utility & solar industry further evaluate methodologies for developing this factor, and Vectren may revise this number in future IRPs.

The historical data column reflects the summer peaking capacity of Vectren's reported net metered customer accounts.[3] The High, Low, and Base Case forecasts for the 2014 – 2034 planning horizon are derived from the following information & data sets:

- Vectren historical growth in net metered inverter-rated capacity,
- Indiana historical growth in net metered inverter-rated capacity, and
- Navigant Consulting solar capacity future growth rate assumptions for Indiana.[4]

High Case (applied to the low energy and demand forecast) calculation methodology is as follows:

- Vectren year-end 2013 inverter-rated capacity (426 kW) grows each year in a compounding manner using Navigant's Indiana predicted growth rates as follows:

[1] Sterling, John, and J. McLaren, M. Taylor, K. Cory. Treatment of Solar Resource Generation in Electric Utility Resource Planning. NREL/TP-6A20-60047. October, 2013.
[2] PJM Manual 21: Rules and Procedures for Determination of Generating Capability, revision 11. PJM System Planning Department. March 5, 2014.
[3] Vectren's Customer-Generator Interconnection and Net Metering Report for year ended 12/13/2013.
[4] Navigant Consulting, 5/2/2014.

  - 2014 – 2025: 40% per year
  - 2025 – 2034: 15% per year
- Each year's result is then multiplied by the factor 0.38 to arrive at the peak planning contribution for distributed solar.

Low Case (applied to the high (modeled) energy and demand forecast) calculation methodology is as follows:

- Vectren year-end 2013 inverter-rated capacity (426 kW) grows each year in a compounding manner using slower growth rates as follows:
  - 2014 – 2025: 34.1% per year
  - 2025 – 2034: 12.8% per year
  - These growth rates are a modified version of the High Case's Navigant Indiana rates based on a derived factor.
    - This growth "adjustment" factor is derived by taking historical net metered capacity growth in Vectren territory versus Indiana as a whole.
    - Specifically, this adjustment factor takes the simple average growth rate for Vectren for the years 2010 through 2012 and divides this result by the simple average growth rate for Indiana over the same period.
    - This adjustment factor is 0.852 (or 85.2%). Applying this factor to Navigant's Indiana growth rates yields the 34.1% and 12.8% values given above.
- Each year's result is then multiplied by the factor 0.38 to arrive at the peak planning contribution for distributed solar.

Base Case (applied the base case and high (large load) energy and demand forecasts) calculation methodology is as follows:

- Takes the simple average of the High and Low cases in each year.

- Each year's result is then multiplied by the factor 0.38 to arrive at the peak planning contribution for distributed solar.

The overall approach for the High, Low, and Base cases is a reflection of the difference in the overall net-metered distributed generation customer adoption rates between Vectren and Indiana. It takes a very high level view of how solar adoption may evolve over a relatively long planning horizon. Vectren believes that the long term nature of the IRP process calls for a high level macro approach, and the Navigant assumptions, while very general in nature, represent the results of expert analysis and therefore are an appropriate basis for making this forecast. Navigant did suggest an "adjustment factor" for the Vectren territory because the Vectren service territory is growing at a slower rate than the state of Indiana, resulting in the use of this in the Low case (and indirect use in the Base Case). The High Case utilizes the unadjusted, original Navigant growth rates (where the Vectren growth rate matches the overall state growth rate).

While distributed solar PV, is the most prominent form of distributed generation anticipated in terms of total numbers of customers, it is not the only DG technology to be considered. Cogeneration, or Combined Heat and Power (CHP), is also a key technology category in the context of the IRP. However, because of the case-by-case nature of these potential resources, and the fact that some could be large enough to be modeled as a generation and/or capacity resource, these are covered outside this section on distributed generation.

Additional future technologies in the distributed generation space include:

- Small wind turbines
- Energy storage
- Fuel cells
- Micro turbines
- Other Micro-CHP (e.g. small advanced engine technologies)

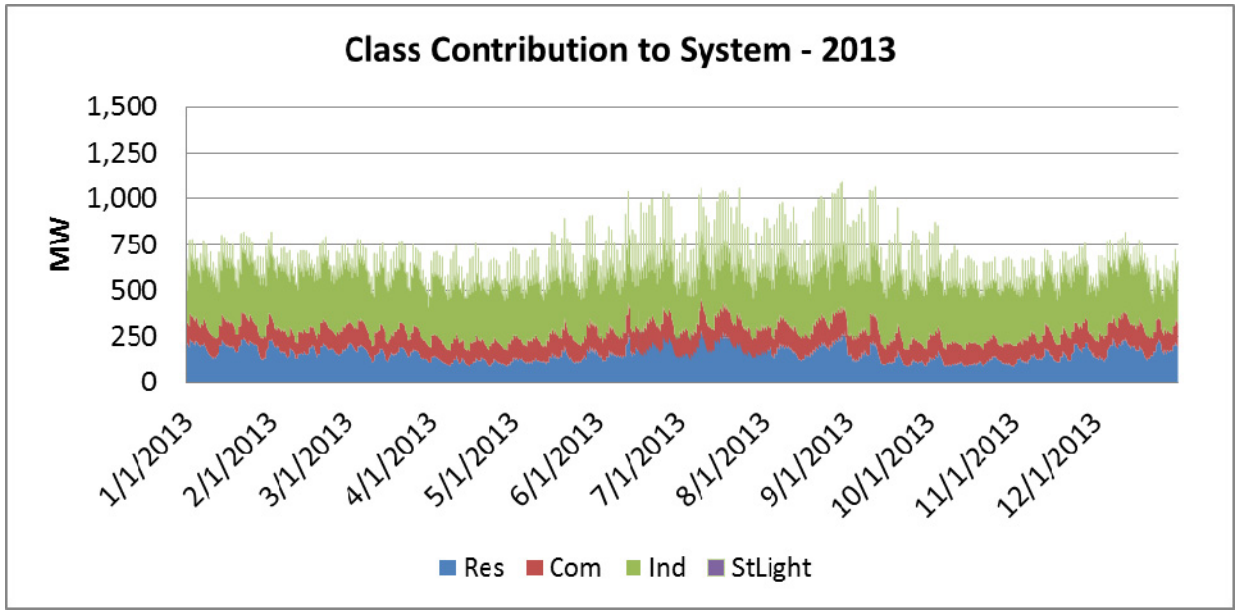
- Micro grids (i.e. customer-sited distribution systems that may include generation and storage technologies)

Each of these technologies will be an important area for the industry to consider in coming years. At this time, none of these are significant enough (or certain enough) to be forecasted as customer-sited DG resources in the present IRP. However, Vectren will continue to monitor and consider how these technologies play into generation planning going forward.

OVERVIEW OF LOAD RESEARCH ACTIVITIES

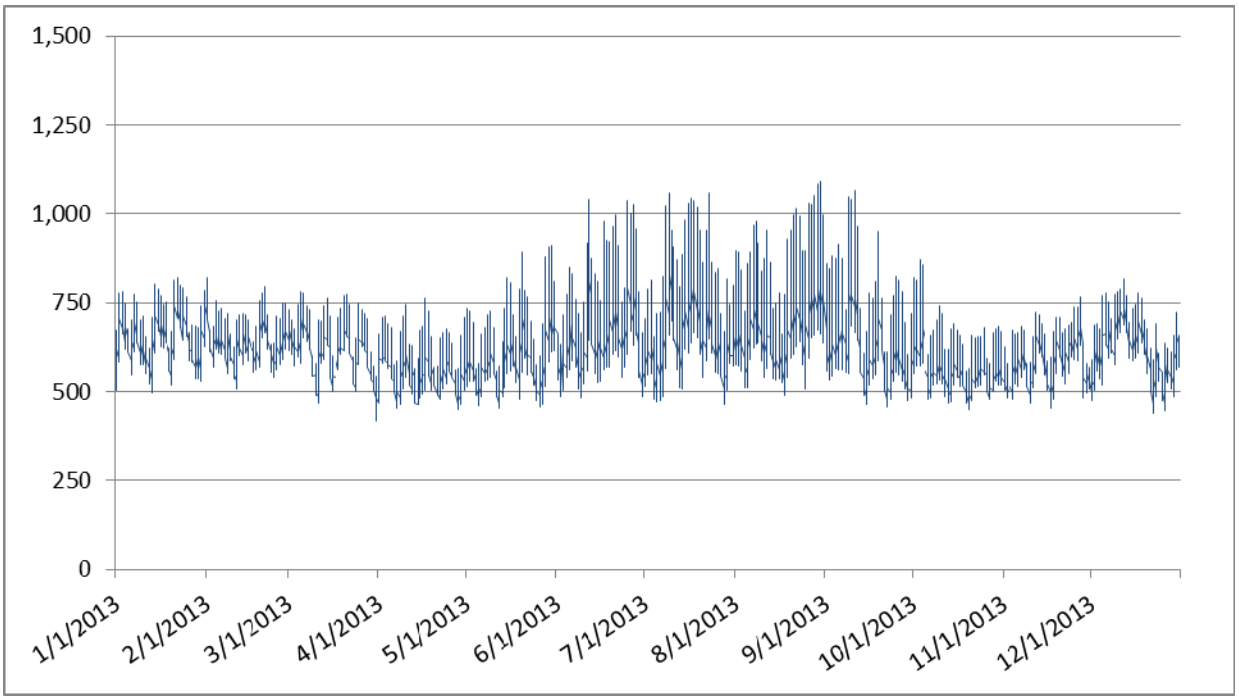
Vectren has interval meters installed on a sample of residential and GS customers. Large customers who have a monthly minimum demand obligation of 300kVA are required to have interval meters installed. Vectren collects and stores this information for analysis as needed. Detailed load shapes are used to better understand customers' usage, primarily for cost of service studies. For this IRP, class load shapes were borrowed from Itron's Indiana library to break down Vectren's hourly load profile by class. The load shapes were applied to historical peak demand. Graph 5-1 shows daily class contribution to peak for 2013.

Graph 5-1 Daily Class Contribution to Peak for 2013 (MW)

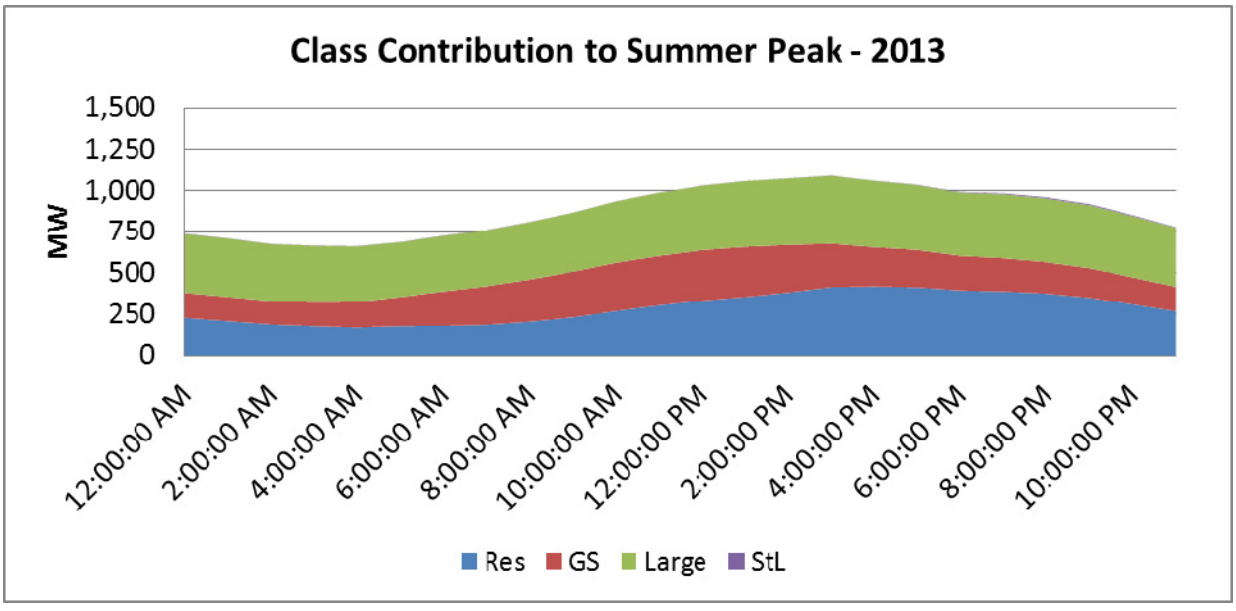


The following graphs (5-2 through 5-4) show the actual system load by day for 2013, the actual summer peak day for 2013 by hour, and the winter peak day for 2013 by hour. Note that these graphs do not include wholesale contract sales. Also additional load shapes are included in the Technical Appendix, section C.

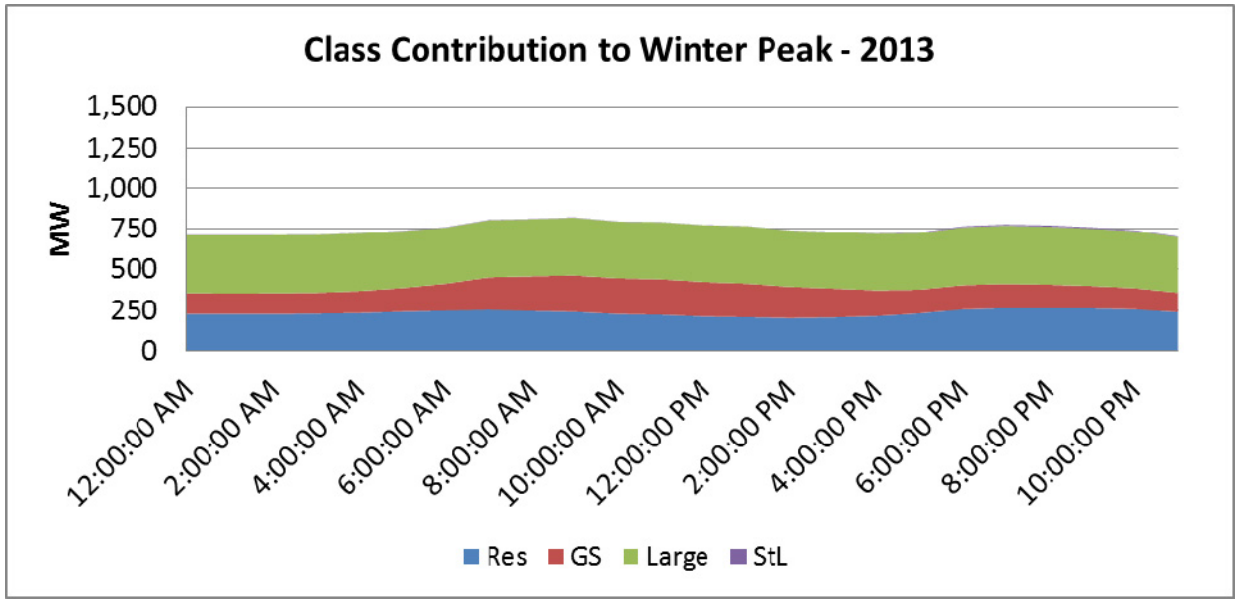
Graph 5-2 Total System Load for 2013 (MW)



Graph 5-3 Summer Peak 2013 (MW)



Graph 5-4 Winter Peak 2013 (MW)



APPLIANCE SATURATION SURVEY AND CONTINUOUS IMPROVEMENT

Vectren typically surveys residential customers every other year. A residential appliance saturation survey was conducted in the summer of 2013. The survey was completed by a representative sample of customers. Results from this survey were used to reflect market shares of actual residential customers. The residential average use model statistics were improved by calibrating East South Central Census regional statistics with the appliance saturation of Vectren's customers. Note that Vectren's service area is technically in the southern most point of the East North Central Census region, bordering the Ease South Central region. Model results were improved by calibrating to the East South Central region.

At this time, Vectren does not conduct routine appliance saturation studies of GS and large customers. These customers are surveyed when needed for special programs. However, Vectren's large and GS marketing representatives maintain close contact with its largest customers. This allows Vectren to stay abreast of pending changes in demand and consumption of this customer group.

Vectren continually works to improve our load forecasting process in a variety of ways. First, Vectren 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. Vectren 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. Vectren forecasters periodically attend continuing education workshops and webinars on various forecasting topics to help improve skills and learn new techniques. Additionally, Vectren discusses forecasts with the State Utility Forecasting Group and other Indiana utilities to better understand their forecasts. We compare and contrast our model assumptions and results to these groups to gain a better understanding of how they interpret and use model inputs.

OVERVIEW OF PAST FORECASTS

The following tables outline the performance of Vectren's energy and demand forecasts. Forecasts from previous IRP filings from 2004 through 2013 were compared to actual values in order to evaluate the reliability of Vectren's past energy and demand forecasts. The following tables show the actual and forecasted values for:

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

Tables 5-6 through 5-10 present comparisons of actual values versus forecasted values from previous IRP filings. The percentage deviation of the actual values from the most recent forecast is shown in the last column of each table. The deviations of the total energy and total peak forecasts are better than for the individual classes, which is to be expected. Note that all of the forecasted values are weather-normalized, but the actual

loads are not. This comparison would show much closer correlation if the actual loads were normalized to match the forecasts. This is particularly true when predicting the peak hour of the year. For example, weather in 2012 was abnormally hot, with multiple 100 degree days in a row, causing the peak demand to be high. 2013 was much milder and, therefore had a lower peak demand. Another factor affecting forecasts is the economic forecast. The recovery from the Great Recession has been much slower than expected. Another source of potential error is the use of the direct load control program, which reduces the peak demand on hot days by cycling off customer appliances to reduce system load. Note that Vectren is not forecasting any firm wholesale contracts after 2014.

Table 5-6 Total Peak Requirements (MW)

		Forecasts						
Year	Actual	2011	2009	2007	2005	2004	2001	Deviation from most recent forecast, %
2004	1,222						1,325	-8.4%
2005	1,316					1,313		0.2%
2006	1,325				1,326			-0.1%
2007	1,341				1,346			-0.4%
2008	1,166			1,184				-1.6%
2009	1,143			1,216				-6.4%
2010	1,275		1,153					9.6%
2011	1,221		1,179					3.4%
2012	1,205	1,168						-3.1%
2013	1,102	1,168						6.0%
Compound Annual Growth Rate, 2004-2013	-1.15%							

Table 5-7 Total Energy Requirements (GWh)

Year	Actual	Forecasts 2011	2009	2007	2005	2004	2001	Deviation from prior IRP forecast, %
2004	6,303						6,437	-2.1%
2005	6,508					6,624		-1.8%
2006	6,352				6,543			-3.0%
2007	6,527				6,210			4.9%
2008	5,931			6,160*				-3.9%
2009	5,598			6,068				-8.4%
2010	6,221		5,608					9.9%
2011	6,244		5,762					7.7%
2012	5,861	5,896						0.6%
2013	5,822	5,867						0.8%
Compound Annual Growth Rate, 2004-2013	-0.88%							

*Adjusted to include wholesale sales

Table 5-8 Residential Energy Sales (GWh)

Year	Actual	Forecasts 2011	2009	2007	2005	2004	2001	Deviation from prior IRP forecast, %
2004	1,502						1,553	-3.4%
2005	1,571					1,546		1.6%
2006	1,475				1,584			-7.4%
2007	1,631				1,609			1.3%
2008	1,435			1,581				-10.1%
2009	1,449			1,595				-10.0%
2010	1,598		1,467					8.2%
2011	1,515		1,451					4.2%
2012	1,456	1,501						-3.1%
2013	1,427	1,483						-3.9%
Compound Annual Growth Rate, 2004-2013	-0.57%							

Table 5-9 General Service Energy Sales (GWh)

Year	Actual	Forecasts (GS) 2011	2009	2007	2005	2004	2001	Deviation from prior IRP forecast, %
2004	1,502						1,408	6.3%
2005	1,556					1,500		3.6%
2006	1,515				1,566			-3.4%
2007	1,412				1,594			-12.9%
2008	1,294			1,380				-6.6%
2009	1,299			1,384				-6.5%
2010	1,361		1,275					6.3%
2011	1,335		1,285					3.8%
2012	1,315	1,387						-5.5%
2013	1,303	1,409						-8.2%
Compound Annual Growth Rate, 2004-2013	-1.57%							

Table 5-10 Large Energy Sales (GWh)

Year	Actual	Forecasts (Large) 2011	2009	2007	2005	2004	2001	Deviation from prior IRP forecast, %
2004	2,346						2,570	-9.5%
2005	2,389					2,619		-9.6%
2006	2,376				2,379			-0.1%
2007	2,538				2,422			4.6%
2008	2,744			2,591				5.6%
2009	2,251			2,598				-15.4%
2010	2,601		2,281					12.3%
2011	2,744		2,445					10.9%
2012	2,714	2,696						0.7%
2013	2,744	2,714						1.1%
Compound Annual Growth Rate, 2004-2013	1.76%							

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CHAPTER 6

ELECTRIC SUPPLY ANALYSIS

INTRODUCTION

The purpose of the electric supply analysis is to determine the best available technologies for meeting the potential future supply-side resource needs of Vectren. A very broad range of supply alternatives were identified in a Technology Assessment described below. These supply alternatives were screened, and a smaller subset of alternatives were chosen for the final planning and integration analysis. Demand side alternatives play a major role in the integrated plan and are discussed in Chapter 8 DSM Resources. The supply-side alternatives which are discussed here fall into two basic categories:

- construction of new generating facilities and
- energy and capacity purchases.

Note that additional DSM energy efficiency programs beyond what was included in the base case energy and demand forecasts were modeled competed with supply-side options to meet future load requirements. This is discussed further in Chapter 8 DSM Resources.

TECHNOLOGY ASSESSMENT

For the 2014 Electric IRP process, Vectren retained the services of Burns & McDonnell, one of the leading engineering design experts in the United States, to assist in performing a Technology Assessment for generation technologies. The Technology Assessment can be found in the Technical Appendix, section B. Below are descriptions of the technologies that were considered from the Technology Assessment.

Natural Gas Technologies

The simple cycle gas turbines (SCGT) utilize natural gas to produce power in a gas turbine generator. The gas turbine 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 their fast load ramp rates and relatively low capital costs.

However, the units have high heat rates compared to other technologies. The different classes of SCGTs are shown below in Table 6-1. Please note that for new natural gas fired units, the capital costs shown in the table above are higher than the overnight costs shown in the Technology Assessment document. A 30% contingency for gas infrastructure siting costs and owner's costs was added for final modeling purposes.

Table 6-1 SGCT Classes

Simple Cycle Gas Turbine				
	LM6000	**LMS100**	**E-Class**	**F-Class**
Base Load Net Output (MW)	49.1	106.4	87.5	212.8
Base Load Net Heat Rate (HHV Btu/kWh)	9,570	8,860	11,480	9,940
Base Project Costs (2014$/kW)	$2,047	$1,440	$1,704	$1,228
Fixed O & M Costs (2014$/kW-yr.)	$23.98	$11.18	$16.56	$7.42

The 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 a steam turbine and generator to produce electric power. The use of both gas and steam turbine cycles in a single plant to produce electricity results in high conversion efficiencies and low emissions. For this assessment, a 1x1, 2x1, and 3x1 power block, as shown in Table 6-2, was evaluated with General Electric (GE) 7F-5 turbines as representative CCGT technology. A 1x1 means one gas or steam turbine is coupled with one HRSG. A 2x1 means two gas or steam turbines are coupled with one HRSG. A 3x1 follows the same pattern, meaning that there are three gas or steam turbines coupled with one HRSG.

Table 6-2 CCGT Classes

Combined Cycle Gas Turbine			
	1x1 F-Class Unfired	**2x1 F-Class Unfired**	**3x1 F-Class Unfired**
Base Load Net Output (MW)	405.5	815.5	1227.1
Base Load Net Heat Rate (HHV Btu/kWh)	6,610	6,530	6,500
Base Project Costs (2014$/kW)	$1,400	$1,083	$925
Fixed O & M Costs (2014$/kW-yr)	$13.51	$7.62	$5.79

The reciprocating engine is the last of the natural gas alternative technologies evaluated. The reciprocating, or piston, engine operates on the conversion of pressure into rotational energy that will fire on natural gas. Fuel and air are injected into a combustion chamber prior to its compression by the piston assembly of the engine. A spark ignites the compressed fuel and air mixture causing a rapid pressure increase that drives the piston downward. The piston is connected to an offset crankshaft, thereby converting the linear motion of the piston into rotational motion that is used to turn a generator for power production. The reciprocating engine is shown in Table 6-3.

Table 6-3 Reciprocating Engine

Reciprocating Engine	
Base Load Net Output (MW)	100.2
Base Load Net Heat Rate (HHV Btu/kWh)	8,470
Base Project Costs (2014$/kW)	$1,677
Fixed O & M Costs (2014$/kW-yr)	$11.79

Coal Technologies

Pulverized coal steam generators are characterized by the fine processing of the coal for combustion in a suspended fireball. Coal is supplied to the boiler from bunkers that direct coal into pulverizers, which crush and grind the coal into fine particles. The primary air system transfers the pulverized coal from the pulverizers to the steam generator's low NO_x burners for combustion. The steam generator produces high-pressure steam for throttle steam to the steam turbine generator. The steam expansion provides the energy required by the steam turbine generator to produce electricity.

Another type of coal technology that was evaluated was the Integrated Gasification Combined Cycle (IGCC) technology. IGCC technology produces a low calorific value syngas from coal or solid waste that can be fired in a combined cycle power plant. The gasification process itself is a proven technology used extensively for chemical production of products such as ammonia for fertilizer.

See Table 6-4 for further details on the coal technologies evaluated.

Table 6-4 Coal Technologies

Coal			
	Supercritical Pulverized Coal 1	**Supercritical Pulverized Coal 2**	**2x1 Integrated Gasification CC**
Base Load Net Output (MW)	425	637.5	482
Base Load Net Heat Rate (HHV Btu/kWh)	10,500	10,200	11,470
Base Project Costs (2014$/kW)	$5,568	$5,080	$10,698
Fixed O & M Costs (2014$/kW-yr)	$32.41	$21.54	$36.88

Waste to Energy Technologies

Stoker boiler technology is the most commonly used waste to energy (WTE) or biomass technology. Waste fuel is combusted directly in the same way fossil fuels are consumed in other combustion technologies. The heat resulting from the burning of waste fuel converts water to steam, which then drives a steam turbine generator for the production of electricity. The two fuel types evaluated in the IRP was wood and landfill gas which are represented in Table 6-5.

Table 6-5 Waste to Energy Technologies

Biomass		
	Wood Stoker Fired	**Landfill Gas IC Engine**
Base Load Net Output (MW)	50	5
Base Load Net Heat Rate (HHV Btu/kWh)	13,500	10,500
Base Project Costs (2014$/kW)	$4,542	$3,261
Fixed O & M Costs (2014$/kW-yr)	$94.49	$182.88

Renewable Technologies

Four renewable technologies were evaluated in the IRP. Those technologies were wind energy, solar photovoltaic, solar thermal, and hydroelectric. Most of the data evaluated was taken from the Technology Assessment, but some data used was from updated studies or real-life examples which will be further discussed below.

Wind turbines convert the kinetic energy of wind into mechanical energy, and are typically used to pump water or generate electrical energy that is supplied to the grid. Subsystems for either configuration typically include a blade or rotor to convert the energy in the wind to rotational shaft energy, a drive train, usually including a gearbox and a generator, a tower that supports the rotor and drive train, and other equipment,

including controls, electrical cables, ground support equipment and interconnection equipment. All the data evaluated for wind energy came from the Technology Assessment.

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 diverse mix of technological designs. Solar conversion technology is generally grouped into Solar Photovoltaic (PV) technology, which directly converts sunlight to electricity due to the electrical properties of the materials comprising the cell, and Solar Thermal technology, which converts the radiant heat of the solar energy to electricity through an intermediary fluid.

Photovoltaic (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 aluminum back-plate on the other.

Solar Thermal technology transfers solar energy to an intermediary liquid (typically mineral oil or molten sodium and potassium nitrate salts) in the form of heat, which is then used to boil water and produce steam. That steam is sent to a Steam Turbine Generator (STG) for the production of electricity. The life expectancy of a solar thermal power plant is similar to that of any fossil fueled thermal plant as long as preventative and routing maintenance programs are undertaken.

Vectren recognized that utility scale solar costs are expected to decline over the next few years and decided to have Burns & McDonnell revisit the solar portion of this Technology Assessment, which had a static cost for solar. Burns & McDonnell's

Phoenix office, which has extensive knowledge of the solar industry, developed an asymptotic curve, beginning at $1,880 per KWac in 2014, and declining to $1,500 per KWac in 2020 and staying flat in real terms for the remainder of the planning horizon. The declining cost curve was used for Vectren's IRP modeling. The costs are represented in Table 6-6.

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. Specially designed low-head hydro turbines are often current driven, and therefore operate at low speeds of 100 to 500 rpm in various configurations and orientations. Since they do not require a large head loss, low-head hydroelectric facilities can be incorporated in a variety of different applications, including rivers, canals, aqueducts, pipelines, and irrigation ditches. This allows the technology to be implemented much more easily than conventional hydropower, with a much smaller impact to wildlife and environmental surroundings. However, power supply is dependent on water supply flow and quality, which are sensitive to adverse environmental conditions such as dense vegetation or algae growth, sediment levels, and drought. Additionally, low-head hydropower is relatively new and undeveloped, resulting in a high capital cost for the relatively small generation output.

Vectren utilized a previously performed study that included dams in and around Vectren's electric service territory to help provide guidance for this IRP. The study was titled *Hydropower Resource Assessment at Non-Powered USACE Sites* and was prepared by the Hydropower Analysis Center for U. S. Army Corps of Engineers. The study was finalized in July 2013.[1] Since there were no costs in the study, Vectren used a real-life example from a hydroelectric construction project in the area to gather the project costs. This data is represented in table 6-6.

[1] Vectren referenced page 28 of this analysis.

Table 6-6 Renewable Technologies

Renewable				
	Wind	**Solar PV**	**Solar Thermal**	**Hydroelectric**
Base Load Net Output (MW)	50	50	50	50
Capacity Factor (energy annual output)	Intermittent (27%)	Intermittent (19%)	Intermittent (19%)	44%
Base Project Costs (2014$/kW)	$2,296	$1,880[1]	$5,740	$4,966
Fixed O & M Costs (2014$/kW-yr)	$25.40	$17.27	$35.56	$76.20

Energy Storage Technologies

Two energy storage technologies were evaluated in the IRP. The technologies were batteries and Compressed Air Energy Storage (CAES). These are shown in Table 6-7.

Electrochemical energy storage systems utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity, ease of installation and operation, and relative design maturity.

CAES offers a way of storing off-peak generation that can be dispatched during peak demand hours. To utilize CAES, the project needs a suitable storage site, either above ground or below ground, and availability of transmission and fuel source. CAES facilities use off-peak electricity to power a compressor train that compresses air into an underground reservoir at approximately 850 psig. Energy is then recaptured by releasing the compressed air, heating it (typically) with natural gas firing, and generating power as the heated air travels through an expander.

[1] $1,880 per KWac in 2014, and declining to $1,500 per KWac in 2020 and staying flat in real terms for the remainder of the planning horizon.

Table 6-7 Energy Storage Technologies

Energy Storage		
	Advanced Battery Energy Storage	**Compressed Air Energy Storage**
Base Load Net Output (MW)	10	135
Base Project Costs (2014$/kW)	$4,135	$1,240
Fixed O & M Costs (2014$/kW-yr)	$60.96	$7.11

Nuclear Technologies

Manufacturers have begun designing Small Modular Reactors (SMRs) to create a smaller scale, completely modular nuclear reactor. These modular reactors are on the order of 30 feet in diameter and 300 feet high. The conceptual technologies are similar to Advanced Pressurized Water Reactors (APWR), and the entire process and steam generation is contained in one modular vessel. The steam generated in this vessel is then tied to a steam turbine for electric generation. The benefit of these SMRs is two-fold; the smaller unit size will allow more resource generation flexibility and the modular design will reduce overall project costs while providing increased benefits in the areas of safety and concern, waste management, and the utilization of resources. The 225 MW SMR facility is shown in Table 6-8.

Table 6-8 Nuclear SMR Technology

Nuclear	
	Small Modular Reactor
Base Load Net Output (MW)	225
Base Load Net Heat Rate (HHV Btu/kWh)	10,300
Base Project Costs (2014$/kW)	$5,415
Fixed O & M Costs (2014$/kW-yr)	$90.42

NEW CONSTRUCTION ALTERNATIVE SCREENING

The first step in the analysis of new construction alternatives was to survey the available list of technologies and to perform a preliminary screening of each of the options, eliminating those options that were determined to be unfeasible or marginal. The power supply alternatives Vectren considered include intermediate and peaking options, as well as renewable generation, energy storage, distributed generation, and demand side management. These power supply alternatives were screened using a bus bar cost analysis. This was done in order to reduce the number of alternatives that were evaluated to a manageable level within Strategist, the planning model.

The screening analysis was performed by developing and comparing levelized cost of each resource over a 20 year period. This simple approach is used to identify and limit the number of higher-cost generation alternatives. For screening purposes, estimated costs included fuel, operation & maintenance, and capital costs. Resources were then compared across various capacity factors in order to compare resource costs across all dispatch levels. Intermittent resources were compared at their respective output levels. Demand side management (DSM) and distributed generation (DG) were not considered in the bus bar analysis, but were considered alternatives within the IRP. See Chapter 5 Sales and Demand Forecast and Chapter 8 DSM Resources for more details.

The set of new construction alternatives that was selected for further assessment as a result of the screening process are presented in Table 6-9. The capital cost and O&M characteristics of these selected alternatives were assessed and developed in detail.

Table 6-9 New Construction Alternatives

Resource[1]	Net Operating Capacity (MW)	Fuel Type	Accepted or Rejected as Resource Alternative	Reason to Accept or Reject
7FA CCGT 1x1	405.5	Natural Gas	Accept	Cost Effective Option
7FA CCGT 2x1	815.5	Natural Gas	Reject	Exceeds capacity needs. If pursuit of a Combined Cycle was needed, would consider coordinating with another utility in order to reduce costs.
7FA CCGT 3x1	1227.1	Natural Gas	Reject	Exceeds capacity needs. If pursuit of a Combined Cycle was needed, would consider coordinating with another utility in order to reduce costs.
1xLM6000	49.1	Natural Gas	Accept	Cost Effective for 50 MW or less
1xLMS100	106.4	Natural Gas	Reject	Not Cost Effective compared to alternatives
1xE-Class SCGT	87.5	Natural Gas	Reject	Not Cost Effective compared to alternatives
1xF-Class SCGT	212.8	Natural Gas	Accept	Cost Effective for low capacity factors
100 MW Recips	100.2	Natural Gas	Accept	Cost Effective for 100 MW or less
500 MW Supercritical Pulverized Coal	425	Coal	Reject	Not Cost Effective compared to alternatives
750 MW Supercritical Pulverized Coal	637.5	Coal	Reject	Not Cost Effective compared to alternatives
2x1 Integrated Gasification Combined Cycle	482	Coal	Reject	Not Cost Effective compared to alternatives
Wood Stoker Fired	50	Biomass	Reject	Not Cost Effective compared to alternatives
Landfill Gas IC Engine	5	Biomass	Reject	Not Cost Effective compared to alternatives
10 MW Adv. Battery Energy Storage	10	Energy Storage	Reject	Not Cost Effective compared to alternatives
135 MW Compressed Air Energy Storage	135	Energy Storage	Reject	Not Cost Effective compared to alternatives
50 MW Wind Energy Conversion	50	Renewables	Accept	Cost Effective Renewable Source
50 MW Solar PV	50	Renewables	Accept	Cost Effective Renewable Source
50 MW Solar Thermal	50	Renewables	Reject	Not Cost Effective compared to PV
50 MW Low-head Hydro	50	Renewables	Reject	Not Cost Effective compared to alternatives
Small Modular Nuclear	225	Uranium	Reject	Not Cost Effective compared to alternatives

[1] Resource options could be structured as a PPA or be utility owned

Gas-Fueled Technologies

Two major types of gas-fired power generation technology, representing six alternatives, were selected for the detailed assessment. These were either simple cycle or combined cycle technology.

- Simple cycle gas turbine (SCGT) technology was evaluated for four levels of generating capability.
- Combined cycle gas turbine (CCGT) technology was evaluated for two levels of generating capabilities.

Simple cycle alternatives were included in the final integration analysis. With respect to the combined cycle alternatives, this assumption was made on the basis of capturing economies of scale and high efficiencies while satisfying the reserve margin and capital investment constraints.

Renewable Technologies

Two renewable resources were included in the final integration analysis. The renewable resources were modeled in 50 MW blocks to be evaluated against the other new construction alternative options. The 50 MW blocks are an installed capacity (ICAP) or generation nameplate designation. The renewable technologies that were selected by the bus bar cost analysis included wind and solar photovoltaic (PV). These renewable resources are intermittent resources, meaning that they are not continuously available due to some factor outside direct control. Given that this analysis is based on unforced capacity (UCAP), the resources are converted from the installed capacity to the unforced capacity based on the percentage of the designated resource. For wind, 9.125% was used to calculate the amount of UCAP available. This effectively makes every 50 MW block of wind worth 4.56 MW towards meeting the UCAP requirement. For solar PV, 38% was used to calculate the amount of UCAP available. This makes every 50 MW block of solar PV worth 19 MW towards meeting the UCAP requirement. See Chapter 5 Sales and Demand Forecast for more details.

PURCHASED POWER ALTERNATIVES

Another set of options available for assisting in meeting future supply-side resource requirements is purchased power from the wholesale electric market for both capacity and/or energy needs. Vectren is a participant in the wholesale electric power market and is a member of the ReliabilityFirst (RF), a regional reliability organization operating within the framework of the North American Electric Reliability Council (NERC). Vectren is also a member of MISO, the independent transmission system operator that serves much of the Midwest and Canada.

Estimating the future market price for electric energy available for purchase is difficult. In general, forward market information for "standard" products is available from brokers, counterparties, and published price indices. However, the liquidity and price transparency of the forward market is inversely proportional to the proximity of the delivery date of the product. The forward market becomes much less liquid (less trade volume) as the delivery date of the product moves further out into the future. Price discovery is more difficult as the more forward products are traded less and therefore less transparent.

Capacity prices within MISO are on an upward trend that may last for several years. Vectren does not foresee a near term need for capacity. In the long run, regional reserve margins will approach equilibrium due to a combination of load growth and generation retirements. Capacity prices may converge with replacement build prices as surplus legacy capacity diminishes through unit retirements and market growth. If at some future point in time Vectren foresees a projected need for capacity, purchased power options will be fully and explicitly considered at that time.

CUSTOMER SELF- GENERATION

Customer self-generation or behind the meter generation is likely to increase in the future. As discussed in in Chapter 5 Sales and Demand Forecast, a future trend of distributed rooftop solar has been projected and included in all scenarios. Somewhat more difficult to predict is the industrial adoption of behind the meter generation. One such facility is planned by a large industrial customer with a proposed implementation in 2017. As these types of projects become known they are incorporated into Vectren's forecasts. They are not however a typical trend, and therefore, are not projected beyond the known projects.

Some large electric customers may be candidates for cogeneration opportunities. Vectren's marketing department is in periodic discussions with customers most likely to participate in such a project. Should such a scenario develop, Vectren would work with that customer to see if they would benefit Vectren's customers to participate in such a project by possibly increasing the output of the cogeneration plant and thus supplying the Vectren system with the excess. Such a project can only be evaluated on a case by case basis.

RENEWABLE TECHNOLOGIES

Wind

As will be discussed further in Chapter 7 Renewables and Clean Energy, Vectren has two separate long-term purchase power agreements for a total of 80 MW of wind name plate capacity. These agreements were included in all integration analysis cases for the entire 20 year study period.

Other

Landfill gas projects and biomass are viable renewable sources of energy. However, due to their typically small relative size and unique site situations required for development, they weren't considered explicitly in the Technology Assessment or included in the integration analysis of this IRP. Vectren believes these technologies may be considered for viable projects in the future, primarily in the context of distributed generation as discussed in the following section, and that such projects will be duly evaluated as they develop.

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CHAPTER 7

RENEWABLES

and

CLEAN ENERGY

CURRENT PROJECTS

Vectren currently receives renewable energy from three projects: two purchase power contracts from Indiana wind projects and one landfill methane gas project.

Benton County Wind Farm

The Benton County Wind Farm, located in Benton County, Indiana, began providing electricity to Vectren in May 2007 under a 20 year purchase power agreement. The nominal nameplate rating for this contract is 30 MW, and the expected annual energy to Vectren from this project is 76,500 MWh.

Fowler Ridge II Wind Farm

Vectren began receiving energy from the Fowler Ridge II wind farm, also located in Benton County, Indiana in December of 2009 under a 20 year purchase power agreement. The nominal nameplate rating for this contract is 50 MW, and the expected annual energy to Vectren from this project is 130,500 MWh.

Blackfoot Landfill Gas Project

Vectren owns the Blackfoot Landfill Clean Energy Project located in Pike County, Indiana. Vectren officially took over ownership of this project on June 22, 2009. This facility consists of 2 internal combustion engine-generator sets that burn methane gas collected from the adjacent Blackfoot Landfill. Total nameplate capacity is 3.2 MW gross combined for the two machines. Vectren projects to produce approximately 15,000 MWh per year from this facility. Pending future expansion of the Blackfoot landfill and corresponding development of a viable gas field, Vectren may consider adding an additional generator set to this facility at some point in the future.

RENEWABLE ENERGY CREDITS

In addition to participation in actual renewable energy projects, both through ownership and purchase power agreements, Vectren will also consider purchasing renewable energy credits (RECs) to meet future renewable mandates. Vectren will monitor the

market development for RECs over the next several years to determine the soundness of such a strategy.

ADDITIONAL RENEWABLE AND CLEAN ENERGY CONSIDERATIONS

Vectren modeled generation characteristics for output at time of peak load and capacity factor based on its geographic footprint. Additional wind generation with characteristics similar to Vectren's existing wind PPA's was also considered. Demand side management programs were considered as clean energy resource options and competed directly with other supply side options in the model.

Table 7-1 Clean Energy Projections

		Clean Energy Source					
	Retail Sales before conservation programs	Wind Generation	Landfill Gas Generation	Conservation Programs	Year-Over-Year Conservation Increase	Customer-Owned DG	Vectren Clean Energy
Year	GWh	GWh	GWh	GWh	GWh	GWh	% of sales
2014	5,832	207.0	15	157		1	7%
2015	5,991	207.0	15	182	26	1	7%
2016	6,040	207.0	15	208	26	2	8%
2017	5,645	207.0	15	233	25	3	9%
2018	5,661	207.0	15	258	25	3	9%
2019	5,680	207.0	15	283	25	5	9%
2020	5,699	207.0	15	296	13	7	9%
2021	5,710	207.0	15	309	13	9	10%
2022	5,729	207.0	15	321	13	12	10%
2023	5,746	207.0	15	334	13	17	10%
2024	5,769	207.0	15	347	13	23	10%
2025	5,782	207.0	15	360	13	32	11%
2026	5,801	207.0	15	373	13	37	11%
2027	5,825	207.0	15	386	13	42	11%
2028	5,860	207.0	15	399	13	48	12%
2029	5,884	207.0	15	412	13	55	12%
2030	5,913	207.0	15	426	13	62	12%
2031	5,942	207.0	15	439	13	71	13%
2032	5,985	207.0	15	453	14	81	13%
2033	6,018	207.0	15	466	14	93	13%
2034	6,060	207.0	15	480	14	106	14%

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CHAPTER 8

DSM RESOURCES

INTRODUCTION

The demand-side resource assessment process is based on a sequential series of steps designed to accurately reflect Vectren's markets and identify the options which are most reasonable, relevant, and cost-effective. It is also designed to incorporate the guidelines from the IURC. This chapter presents a discussion of the planning and screening process, identification of the program concepts, and a listing of the demand-side management (DSM) options passed for integration. Additionally, IRP DSM modeling is discussed.

HISTORICAL PERFORMANCE

Since 1992, Vectren has utilized DSM as a means of reducing customer load and thereby providing reliable electric service to its customers. Historically, DSM programs provided both peak demand and energy reductions. DSM programs were approved by the Commission and implemented pursuant to IURC orders. These programs were implemented, modified, and discontinued when necessary based on program evaluations. Vectren has managed the programs in an efficient and cost effective manner, and the load reductions and energy savings from the programs have been significant. Between 2010 and 2013, Vectren DSM programs reduced demand by over 25,000 kW and provided annual incremental energy savings of over 130,000,000 kWh. It is anticipated that in 2014, Vectren will save an incremental 58,000,000 kWh of gross energy savings and approximately 15,000 kW in demand savings.

Vectren also operates a Direct Load Control (DLC) program that reduces residential and small commercial air-conditioning and water heating electricity loads during summer peak hours. This demand response program commenced in 1992 and over 27,000 customers are enrolled with approximately 17 MW of peak reduction capacity.

EXISTING DSM RESOURCES and PROGRAMS

Tariff Based Resources

Vectren has offered tariff based DSM resource options to customers for a number of years. Consistent with a settlement approved in 2007 in Cause No. 43111, the Demand Side Management Adjustment ("DSMA") was created to specifically recover all of Vectren's DSM costs, including (at that time) a DLC Component. The Commission, in its order in Cause No. 43427, authorized Vectren 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 available to rate schedule RS, B, SGS, DGS, MLA, OSS, LP, and HLF customers.

Interruptible Rates

In addition to the DSM programs described in this chapter, Vectren has offered interruptible rate programs for commercial and industrial customers. Vectren currently has approximately 47 MW of interruptible load under contract, not including the
DLC Program. In addition to the riders listed below, Vectren has one customer on a special contract interruptible rate (as approved by the IURC), that makes up approximately 20 MW of the total 47 MW of interruptible load.

<u>Rider IP – 2 Interruptible Power Service</u>

This rider is available to rate schedule DGS, OSS, LP, and HLF customers with an interruptible demand of at least 200 kW who were taking service under this rider during September 1997. This rider is closed to new participants. This rider currently has two customers that represent approximately 6 MW of the total interruptible load.

Rider IC Interruptible Contract Rider

This rider is available to any rate schedule LP or HLF customer electric who can provide for not less than 1,000 kVa of interruptible demand during peak periods. This rider currently has two customers that represent approximately 21MW of the total interruptible load.

Rider IO Interruptible Option Rider

This rider is available to any rate schedule DGS, MLA, OSS, LP, or HLF customer who will interrupt a portion of their normal electrical load during periods of request from Vectren. A Customer's estimated load interruption capability must exceed 250 kW to be eligible. This rider is not applicable to service that is otherwise interruptible or subject to displacement under rate schedules or riders of Vectren. Customers currently taking service under Vectren's rider IP – 2, which is closed to new business, may apply for service under this rider, if eligible, for the balance or renewal of the existing contracts.

Direct Load Control (DLC)

The DLC program provides remote dispatch control for residential and small commercial air conditioning, electric water heating and pool pumps (on existing units only) through radio controlled load management receivers (LMR). The DLC program was implemented in April 1992 by Vectren, with the objective of reducing summer peak demand by direct, temporary cycling of participating central air conditioners and heat pumps and by shedding connected water heating and pool pump loads. Participating customers receive credits on their bills during the months of June through September based on the number and type of equipment participating in the program. The DLC program was identified, in 2007, as part of Vectren's DSM Market Assessment study, prepared by Forefront Economics Inc. and H. Gil Peach & Associates LLC, as "…of high quality and notable for its participation and program longevity." Vectren's customers have achieved significant benefits from the existing DLC program.

The program consists of the remote dispatch and control of a DLC switch installed on participating customers' central cooling units (central air conditioners and heat pumps), as well as electric water heating units where a DLC switch is also installed on the central cooling unit. Vectren can initiate events to reduce air-conditioning and water-heating electric loads during summer peak hours. Vectren can initiate a load control event for several reasons, including: to balance utility system supply and demand, to alleviate transmission or distribution constraints, or to respond to load curtailment requests from the Midcontinent Independent Transmission System Operator, Inc. (MISO), the regional electricity transmission grid authority. The control of central cooling units is typically a 50% cycling strategy and involves cycling the compressor off for 15 minutes out of every half hour during the cycling period. The direct load control of water heating equipment utilizes a shedding strategy. This involves shutting off these units for the duration of the cycling period. Cycling periods can range between two and six hours in duration.

Vectren 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. Vectren also utilizes an outside vendor, The Cadmus Group, to evaluate the DLC program and provide unbiased demand and energy savings estimates.

The DLC system has the capability to obtain approximately 17 MW of peak reduction capacity from the DLC system. Over time, the operability of the DLC switches can decline for a variety of reasons, including mechanical failure, contractor or customer disconnection, and lack of re-installation when customer equipment is replaced. In order to continue to obtain the peak demand response benefits from the DLC system, Vectren requested and received Commission approval of a multi-year DLC Inspection & Maintenance Program in Cause No. 43839. This inspection process began in 2011 with approximately 25% of the DLC switches inspected annually and this process will be

completed early in 2015. Vectren has proposed in Cause No. 43405 DSMA 12 to continue ongoing maintenance of DLC switches on a five (5) year cycle with approximately 20% inspected annually. The work will continue to be conducted by trained vendors for both the inspection and replacement components of the program. By investing in the inspection and maintenance of the DLC system, Vectren can continue its ability to rely on this demand reduction resource as part of its resource planning.

As of May 2014, Vectren's DLC Program had approximately 27,040 residential customers and 530 commercial customers with a combined total of over 36,000 switches. Note that a customer may have more than one switch at a residence or business.

Cause No. 43839 – Rate Design

In Cause No. 43839, approved by the IURC on May 3, 2011, specific structural rate modifications were proposed by Vectren to better align Vectren's rate design to encourage conservation. These structural changes include:

- For all rate schedules, Vectren separated its variable costs from its fixed costs. These changes are intended, among other things, to provide more clarity and transparency in the rate schedules as to the variable costs that Vectren customers can avoid as customers reduce usage.
- Combined the customers under Rate A (the "Standard" customers) and Rate EH (the "Transitional" customers) into a single rate schedule, called Rate RS - Residential Service. The results of these changes resulted in the elimination of the Rate A declining block rate design in favor of a single block rate design for the Rate RS - Standard customer group versus the previous declining block rates. The transition from a declining block rate design to a flat block rate design has been recognized as a method to encourage energy conservation.
- The availability of Rate RS-Transitional was closed to new customers on May 3, 2012 in order to eliminate the promotion of all-electric space heating. A transition

plan to gradually move the existing Rate RS-Transitional customers to RS-Standard was to be filed for the Commission's consideration within two years of Vectren's most recent electric rate case on May 3, 2011. Vectren filed with the Commission a report on the Transition Plan on April 23, 2013 and recommended that any transition plan be considered in the next base rate case. The Commission has not yet ruled on this matter.

- The availability of the commercial Rate OSS (Off Season Service) was also closed to new customers on May 3, 2012 in order to eliminate the promotion of all-electric space heating. A transition plan to gradually move the existing Rate OSS customers to a comparable Rate DGS was to be filed for the Commission's consideration within two years of Vectren's most recent electric rate case on May 3, 2011. Vectren filed with the Commission a report on the Transition Plan on April 23, 2013 and recommended that any transition plan be considered in the next base rate case. The Commission has not yet ruled on this matter.

In Vectren's last electric base rate case, the Company proposed a decoupling mechanism that would break the link between recovery of fixed costs and energy sales in order to eliminate the financial harm to the Company caused when customers reduce their electric usage, thereby supporting the Company's ability to aggressively promote energy conservation. The Commission ultimately denied this request in their April 27, 2011 Order.

The rate structure listed above is reflected in the long term sales and demand forecast.

MISO DR Program

Vectren rider DR provides qualifying customers the optional opportunity to reduce their electric costs through customer provision of a load reduction during MISO high price periods and declared emergency events. Rider DR currently offers two programs, emergency demand response ("EDR") and demand response resource Type 1 ("DRR-1") energy programs.

Rider DR is applicable to any customer served under rates DGS or OSS with prior year maximum demand greater than 70 kW, MLA, LP, or HLF. A customer may participate in the rider DR only with kVa or kW curtailment load not under obligation pursuant to rider IC or IO or special contract. Customers must offer Vectren a minimum of one (1) MW of load reduction, or the greater minimum load reduction requirement that may be specified by the applicable MISO BPM for the type of resource offered by customer. A customer may participate in an aggregation as described in the Rider DR in order to meet the minimum requirement.

Vectren currently does not have any customers participating in rider DR.

Net Metering – Rider NM

Rider NM allows certain customers to install renewable generation facilities and return any energy not used by the customer from such facilities to the grid. On July 13, 2011 the Commission published an amended net metering rule, which included additional modifications to the rules, including eligibility to all customer classes, increase to the size of net metering facilities (1 MW) and an increase in the amount of net metering allowed (1% of most recent summer peak load or approximately 11.5 MW). The new rules also required that at least forty percent (40%) of the amount of net metering allowed would be reserved solely for participation by residential customers.

Vectren has worked with customers over the past several years to facilitate the implementation of net metering installations. As of July 1st, 2014, Vectren had 69 net metering customers with a total nameplate capacity of 474 kW.

Smart Grid Resources

Smart Grid technology has the potential to enable higher levels of reliability, energy efficiency and demand response, as well as improved evaluation, measurement, and verification of energy efficiency and demand response efforts. Reliability can be improved through distribution automation (DA) enhancements. These enhancements

can provide operators with real-time information that allows them to make operational decisions more quickly to restore customers following an outage or possibly avoiding the outage completely. Additionally the enhancements can provide automation that can identify fault location, isolate and restore the customers quickly without operator intervention. The advanced metering infrastructure (AMI) portion of a Smart Grid project, as well as new dynamic pricing offerings, enable those customers who decide to actively manage their energy consumption to have access to significantly more information via enhanced communication. This provides those customers a better understanding and more control of their energy consumption decisions and the resulting energy bills. These improvements can provide benefits toward carbon foot print reduction as a result of the overall lowered energy consumption. The potential DSM benefits related to Smart Grid include:

- Peak reductions resulting from enabling Vectren customers to actively participate in demand response programs via dynamic pricing programs,
- Enhanced load and usage data to the customer to foster increased customer conservation, and
- Conservation voltage and line loss reductions due to the improved operating efficiency of the system.

In 2009, as part of the funding available from the United States Department of Energy (DOE) pursuant to American Recovery and Reinvestment Act (ARRA), Vectren conducted a business case analysis of the broad benefits of a Smart Grid implementation. According to the October 27, 2009 DOE announcement, Vectren did not receive a grant award for the Smart Grid project. Vectren re-evaluated the business case and determined that it would not be prudent to proceed with a broad Smart Grid project at this time due to net costs to customers. As part of this initiative Vectren completed the development of an initial Smart Grid strategy where it identified the need to invest in some foundational communication and information gathering technology in order to support future demand response and load management technology. The initial focus of the strategy is to build out a communication network that will support current

and future Smart Grid technology, such as distribution Supervisory Control and Data Acquisition (SCADA), AMI, conservation voltage reduction (CVR), and system automation. Vectren has implemented a fiber optic communication path across its transmission network, connecting at both primary generating stations. Additional fiber installations are in progress across the transmission grid. The build out of the communication system has allowed Vectren to install and monitor additional SCADA points from its distribution substations. These SCADA installations are fundamental to the potential implementation of future conservation and voltage management programs, such as CVR, on the distribution network. Vectren will continue to monitor and evaluate Smart Grid technologies and customer acceptance of Smart Grid enabled energy efficiency and demand response.

Vectren recognizes the potential benefits Smart Grid technology programs offer. While a comprehensive Smart Grid deployment is likely several years in the future, the goal of any Vectren Smart Grid project will be to improve reliability, reduce outage restoration times, and increase energy conservation capabilities. The foundational investments currently being made and those planned over the next few years will enhance Vectren's ability to achieve these benefits.

The potential impacts of a robust Smart Grid implementation that would include dynamic pricing, improved information or conservation voltage reduction have not been explicitly quantified in this IRP because no specific project of this magnitude has been proposed by Vectren. We continue to monitor these technologies for potential future implementation as they become cost effective for our customers.

FEDERAL AND STATE ENERGY EFFICIENCY DEVELOPMENTS

Federal – Codes, Standards and Legislation

Energy efficiency policies are gaining momentum at both the state and Federal level. Although there are numerous activities going on at the state and Federal level the

following are components of significant legislation that are approaching implementation, as well as new codes, standards and legislation being considered that will likely have an impact on energy efficiency in the planning horizon.

- On June 2, 2014, the EPA released its Clean Power Plan proposal that, if implemented, will for the first time regulate carbon dioxide (CO_2) emissions from existing power plants at the U.S. federal level. The rule is designed to cut carbon pollution from power plants nationwide by 30 percent from 2005 levels. State compliance includes several paths, one of which is end use energy efficiency. While dependent on the actual state implementation plan, the proposed plan would require reductions of 0.57% starting in 2017 and ramping up to 1.5% annually from 2022-2036. By 2030, the EPA is looking for usage reductions in Indiana of 11.6% in cumulative savings and that number increases to 12.9% in cumulative savings by 2036. As this rule is developed and finalized, it is likely to have potential significant impacts on energy efficiency planning.
- The U.S. Department of Energy's Appliances and Equipment Standards Program develops test procedures and minimum efficiency standards for residential appliances and commercial equipment. On June 27, 2011, amended standards were issued for residential central air conditioners and heat pumps. Central air conditioners and central air conditioning heat pumps manufactured on or after January 1, 2015 will have minimum requirements for Seasonal Energy Efficiency Ratios (SEER) and Heating Seasonal Performance Factors (HSPF).

State – Codes, Standards and Legislation

Since 2009, Indiana has taken several significant steps to enhance energy efficiency policy in the state.

- In 2009, the IURC released the Phase II Generic DSM order. The order established statewide electric savings goals for utilities starting in 2010 at

0.3% of average sales and ramping to 2% per year by 2019, The Phase II order also defined a list of five (5) Core DSM programs to be offered by a statewide Third Party Administrator (TPA) and allowed utilities the option to offer Core Plus programs in an effort to reach the 2% goal.

- As a result, since 2012, a statewide TPA has been running Core DSM Programs in Indiana. In March 2014, the Indiana General Assembly passed legislation which modified DSM requirements in Indiana. Senate Enrolled Act No. 340 ("SEA 340") removed requirements for mandatory statewide "Core' DSM programs and savings requirements established in the Phase II Order. SEA 340 also allows large C&I customers who meet certain criteria to opt-out of participation in utility sponsored DSM programs. Furthermore, the statute goes on to prohibit the Commission from requiring jurisdictional electric utilities to meet the Phase II Order energy savings targets after December 31, 2014 and prohibits jurisdictional electric utilities from renewing or extending an existing contract or entering into a new contract with a statewide third party administrator for an energy efficiency program as established in the Phase II Order.
- As a result of SEA 340, Vectren filed and received approval for a one year DSM plan for 2015 under Cause No. 44495 with a savings target of 1% of eligible customer sales.

VECTREN DSM STRATEGY

Vectren has adopted a cultural change that encourages conservation and efficiency for both its gas and electric customers. Vectren has embraced energy efficiency and actively promotes the benefits of energy efficiency to its employees and customers. Vectren has taken serious steps to implement this cultural change starting with its employees. Vectren encourages each employee, especially those with direct customer contact, to promote conservation. Internal communications and presentations, conservation flyers and handouts, meetings with community leaders, and formal training have all promoted this shift. This cultural shift was a motivating factor in launching a

new Vectren motto of "Live Smart" in order to further emphasize efficiency. Vectren's purpose statement is the foundation of the Vectren Strategy related to DSM:

> *Purpose*
> With a focus on the need to conserve natural resources, we provide energy and related solutions that make our customers productive, comfortable and secure.

Customers are a key component of Vectren's values, and Vectren knows success comes from understanding its customers and actively helping them to use energy efficiently.

Vectren will continue to offer cost-effective DSM to assist customers in managing their energy bills and meet future energy requirements. Vectren will include an on-going level of Vectren sponsored DSM in the load forecast and will also consider additional DSM as a source of new supply in meeting future electric service requirements (discussed further in the IRP DSM modeling section of this chapter). DSM savings levels in the load forecast include DSM energy efficiency programs available to all customer classes and a 1% annual savings targets for 2015-2019 and .5% annually thereafter. The 1% of eligible annual savings target assumes that 70% of eligible large customer load will opt-out of DSM programs using the provision provided in SEA340.[1] The load forecast also includes an ongoing level of energy efficiency related to codes and standards embedded in the load forecast projections. Ongoing DSM is also important given the integration of Vectren's gas and electric efficiency programs.

DSM PLANNING PROCESS

The following outlines Vectren's planning process in support of Vectren's strategy to identify cost effective energy efficiency resources. In 2006, as a result of a settlement in

[1] Vectren assumes that 80% of large customers will opt out of Vectren sponsored DSM programs; however, 70% was selected for large sales modeling to capture large customer energy efficiency projects outside of Vectren sponsored programs.

Cause No. 42861, the DSM Collaborative was formed, including Vectren and the Indiana Office of Utility Consumer Counselor ("OUCC") as voting members. The Collaborative provided input in the planning of Vectren's proposed DSM programs. The Oversight Board was formed as a result of Cause No. 43427 and was given authority to govern Vectren'sElectric DSM Programs. When formed, the Oversight Board included Vectren and the OUCC as voting members. The Citizens Action Coalition ("CAC") was added as a voting member of the Oversight Board in 2013 as a result of Cause No. 44318.

The IURC Phase II Order in Cause No. 42693 issued on December 9, 2009 established energy saving goals for all jurisdictional utilities in Indiana. The Phase II Order required all jurisdictional utilities to implement five specified programs, which the Commission termed Core Programs. The Core Programs were administered by a third party administrator (TPA) selected through a process involving the Demand Side Coordination Committee composed of jurisdictional Investor-Owned Utilities (IOU's) and other pertinent key stakeholders.

Additionally, the Commission recognized that achieving the goals set out in the Phase II Order would not be possible with Core Programs alone and encouraged the utilities to implement Core Plus Programs to assist in reaching the annual savings goals. Core Plus programs are those programs implemented by the jurisdictional electric utilities in Indiana designed to fill the gap between savings achieved by the Core programs and the savings targets established by the Commission in the Phase II Order. To develop its own set of Core Plus programs, Vectren modified existing programs approved in Cause No. 43427 and added new programs, which were approved on August 31, 2011 in Cause No. 43938. During this period, Vectren also proceeded to integrate some of its electric programs with existing gas DSM programs.

However, with the passage of SEA 340, mandatory statewide "Core" DSM programs and savings requirements established in the Phase II Order have been removed as of

December 31, 2014 and large C&I customers who meet certain criteria ("Qualifying Customers") are allowed to opt-out of participation in Company sponsored energy efficiency programs. As a result, Vectren has implemented an opt-out process as defined in IURC Cause No. 44441 to allow Qualifying Customers to opt-out. This process includes defined annual opt-out and opt-in periods. The plan that Vectren initially filed for 2015 in IURC Cause No. 44495 on May 31, 2014 assumed a 50% level of opt-out. During the initial opt-out period effective July 1, 2014, approximately 71% of eligible large C&I retail sales opted out of participation in Company sponsored DSM. The higher than anticipated opt-out required Vectren to adjust the 2015 Plan to reflect lower spending and lower available savings potential because of the additional portion of the load that is no longer participating in DSM programs. There is an additional opt-out period in the fall of 2014 effective January 1, 2015. As a result, Vectren revised the 2015 Plan to adjust for an 80% opt-out level effective January 1, 2015. The revised plan was approved by the Oversight Board and is still pending Commission approval as part of Cause No. 44495.

The 2015 Plan was developed during an IRP planning period; therefore, the 2014 IRP could not serve as a key input into the 2015 Plan. As a result, the avoided cost basis from the 2011 IRP was used to develop the 2015 Plan. The framework for the 2015 Plan is a continuation of programs offered in 2014, at a savings level of 1.2% of sales (adjusted for the assumption that 80% of Qualifying Customers will opt-out of the programs). However, there were many steps involved in developing the 2015 Plan. The objective of these steps was to develop a plan based on market-specific information for Vectren, which could be successfully implemented utilizing realistic assessments of achievable market potential.

The first step in the process was retaining EnerNOC to complete a Market Potential Study[1] (MPS), included in the Technical Appendix, section D. At the end of 2012,

[1] Electric Demand Side Management: Market Potential Study and Action Plan, EnerNOC Utility Solutions Consulting, April 22, 2013

Vectren, with guidance from the Vectren Electric Oversight Board, engaged EnerNOC, Inc. to study its DSM market potential and develop an Action Plan. EnerNOC conducted a detailed, bottom-up assessment of the Vectren market in the Evansville metropolitan area to deliver a projection of baseline electric energy use, forecasts of the energy savings achievable through efficiency measures, and program designs and strategies to optimally deliver those savings. The study developed technical, economic and achievable potential estimates by sector, customer type and measure. According to the MPS, EnerNOC performed the following tasks in completing the study:

1. Conducted onsite energy consumption surveys with 30 of Vectren's largest commercial and industrial customers in order to provide data and guidance for these market sectors that had not formerly received focused DSM program efforts.
2. Performed a market characterization to describe sector-level electricity use for the residential, commercial, and industrial sectors for the base year, 2011. This included using existing information contained in prior Vectren and Indiana studies, new information from the aforementioned onsite surveys with large customers, EnerNOC's own databases and tools, and other secondary data sources such as the American Community Survey (ACS) and the Energy Information Administration (EIA).
3. Developed a baseline electricity forecast by sector, segment, and end use for 2011 through 2023. Results presented in this volume focus on the upcoming implementation years of 2015 through 2019.
4. Identified several hundred measures and estimated their effects in five tiers of measure-level energy efficiency potential: Technical, Economic, Achievable High, Achievable Recommended and Achievable Low.
5. Reviewed the current programs offered by Vectren in light of the study findings to make strategic program recommendations for achieving savings.
6. Created recommended program designs and action plans through 2019 representing the program potential for Vectren, basing them on the potential analysis and strategic recommendations developed in the previous steps.

The EnerNOC MPS and other study information were used to help guide the plan design. Study analysis and results details can be found in the MPS and its appendices. For planning purposes Vectren used the "Recommended Achievable" scenario as a guide for developing the 2015 Plan.

The second primary step in the planning process was to hire outside expertise to assist with the plan design and development. Vectren retained Morgan Marketing Partners to assist with designing the 2015 Plan. Rick Morgan, President of Morgan Marketing Partners, was the primary planner working with the Vectren team.

The third primary step in the planning process was to obtain input from various sources to help develop and refine a workable plan. The first group providing input was Vectren's DSM Program Managers who have been overseeing current Vectren programs. In addition, vendors and other implementation partners who operate the current programs were very involved in the process as well. They provided suggestions for program changes and enhancements. The vendors and partners also provided technical information about measures to include recommended incentives, estimates of participation and estimated implementation costs. These data provided a foundation for the 2015 Plan based on actual experience within Vectren's territory. These companies also bring their experience operating programs for other utilities.

Other sources of program information were also considered. Current evaluations were used for adjustments to inputs. In addition, best practices were researched and reviewed to gain insights into the program design of successful DSM programs implemented at other utilities. Once the plan was developed, Vectren obtained feedback and approval from the Oversight Board before finalizing.

DSM SCREENING RESULTS

The last step of the planning process was the cost benefit analysis. Utilizing a cost / benefit model, the measures and programs were analyzed for cost effectiveness. The outputs include all the California Standard Practice Manual results including Total Resource Cost (TRC), Utility Cost Test (UCT), Participant and Ratepayer Impact Measure (RIM) tests. Inputs into the model include the following: participation rates, incentives paid, energy savings of the measure, life of the measure, implementation costs, administrative costs, incremental costs to the participant of the high efficiency measure, escalation rates and discount rates. Vectren considers the following tests and ensures that the portfolio passes the TRC test as this test includes the total costs and benefits to both the utility and the consumer. Table 8-4 below outlines the results of all tests.

The model includes a full range of economic perspectives typically used in energy efficiency and DSM analytics. The perspectives include:

- Participant Test
- Utility Cost Test
- Ratepayer Impact Measure Test
- Total Resource Cost Test

The cost effectiveness analysis produces two types of resulting metrics:

1. Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
2. Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

As stated above, the cost effectiveness analysis reflects four primary tests. Each reflects a distinct perspective and has a separate set of inputs reflecting the treatment of costs and benefits. A summary of benefits and costs included in each cost effectiveness test is shown below in Table 8-1.

Table 8-1 Vectren 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
Utility 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
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
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)

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

The Ratepayer Impact Measure (RIM) Test shows the impact of a program on all utility customers through impacts in 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 Total Resource Cost (TRC) Test shows the combined perspective of the utility and the participating customers. This test compares the level of benefits associated with the reduced energy supply costs to utility programs and participant costs.

In completing the tests listed above, Vectren used 7.29% as the weighted average cost of capital, which is the weighted cost of capital that was approved by the IURC on April 27, 2011 in Cause No. 43839. For the 2015 Plan, Vectren utilized the avoided costs from Table 8-4 in the 2011 IRP. The avoided costs listed below in Table 8-2 were not yet available when the 2015 Plan was developed and filed with the Commission. As the 2015 Action Plan is finalized in late 2014, Vectren will use the avoided costs from the table below and also for any future modeling of DSM programs for 2016 and beyond. Vectren conducts IRPs every two years. Note that The avoided generating capacity costs are reflective of the estimated replacement capital and fixed operations and maintenance cost for an F-class simple cycle gas turbine, as discussed in Table 6-1 SGCT Classes. The operating and capital costs are assumed to escalate with inflation throughout the study period. The cost assumptions can be found in the Technical Appendix, section B. Transmission and distribution capacity are accounted for within the transmission and distribution avoided cost. Vectren's planning reserve margin position is not factored into the avoided capacity cost as presented. Under the base sales forecast, Vectren does not require additional capacity to meet the planning reserve margin requirement throughout the study period.

The marginal energy cost are reflective of the modeled Vectren system marginal cost of energy from the base scenario under base assumptions. This included variable transaction purchase, emission costs for CO_2 starting in 2020, 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 variable system costs reflected in this calculation can be found in the Technical Appendix, section B.

Table 8-2 Vectren Avoided Costs

	Capacity Surplus / (Deficit)	Generation Avoided Cost	Transmission / Distribution Avoided Cost	Total Capacity Avoided Cost	Marginal Energy Cost	Marginal Energy Cost
	MW	$/kW	$/kW	$/kW	$/MWh	$/kWh
2015	81	$104.01	$10.40	$114.41	$36.94	$0.0369
2016	80	$105.67	$10.57	$116.24	$43.32	$0.0433
2017	102	$107.36	$10.74	$118.10	$45.01	$0.0450
2018	106	$109.08	$10.91	$119.99	$47.58	$0.0476
2019	109	$110.82	$11.08	$121.91	$49.42	$0.0494
2020	109	$112.60	$11.26	$123.86	$63.16	$0.0632
2021	109	$114.40	$11.44	$125.84	$65.23	$0.0652
2022	108	$116.23	$11.62	$127.85	$67.44	$0.0674
2023	108	$118.09	$11.81	$129.90	$69.84	$0.0698
2024	108	$119.98	$12.00	$131.98	$73.54	$0.0735
2025	109	$121.90	$12.19	$134.09	$76.04	$0.0760
2026	109	$123.85	$12.38	$136.23	$79.06	$0.0791
2027	108	$125.83	$12.58	$138.41	$81.84	$0.0818
2028	106	$127.84	$12.78	$140.63	$85.11	$0.0851
2029	105	$129.89	$12.99	$142.88	$89.11	$0.0891
2030	104	$131.97	$13.20	$145.16	$92.79	$0.0928
2031	104	$134.08	$13.41	$147.49	$96.21	$0.0962
2032	102	$136.22	$13.62	$149.85	$100.77	$0.1008
2033	101	$138.40	$13.84	$152.24	$105.98	$0.1060
2034	100	$140.62	$14.06	$154.68	$110.93	$0.1109

A review of the benefit/cost results for each of the technologies considered in the screening analysis is detailed in Table 8-3. Note that measures with a benefit-cost ration of 0.00 indicates no direct technology costs are applied.

Table 8-3 Vectren DSM Technology Screening Results

Residential Technology Analysis Results

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
1	30% Infil. Reduction Electric Furnace no CAC V IQW109	$458	N/A	$118	1.11	$785	3.17	$785	3.17
2	30% Infil. Reduction Electric Furnace w/ CAC V IQW107	$55,076	N/A	$15,424	1.13	$95,634	3.23	$95,634	3.23
3	30% Infil. Reduction Gas Furnace no CAC V IQW111	$55	N/A	($558)	0.18	($478)	0.21	($478)	0.21
4	30% Infil. Reduction Gas Furnace w/ CAC	$19,901	N/A	($58,161)		($29,178)		($29,178)	

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
	V IQW110				0.44		0.61		0.61
5	30% Infil. Reduction Heat Pump V IQW108	$6,012	N/A	$226	1.02	$8,981	2.63	$8,981	2.63
6	5th Grade Kit- Air Filter Alarm V RES113	$16,471	N/A	$8,159	1.29	$31,187	7.34	$31,187	7.34
7	5th Grade Kit- Bathroom Aerator 1.0 gpm V RES110	$5,758	N/A	$671	1.07	$7,862	3.52	$7,862	3.52
8	5th Grade Kit- CFL - 13 W V RES111	$40,416	N/A	($28,761)	0.61	$15,287	1.51	$15,287	1.51
9	5th Grade Kit- CFL - 23 W V RES112	$65,788	N/A	($43,510)	0.63	$28,191	1.63	$28,191	1.63
10	5th Grade Kit- Kitchen Flip Aerator 1.5 gpm V RES109	$2,879	N/A	($1,431)	0.79	$2,165	1.65	$2,165	1.65
11	5th Grade Kit- LED Nightlight V RES114	$16,172	N/A	($15,326)	0.50	$4,874	1.46	$4,874	1.46
12	5th Grade Kit- Low Flow Showerhead 1.5 gpm V RES108	$35,128	N/A	($7,034)	0.89	$31,250	2.29	$31,250	2.29
13	Air Source Heat Pump 16 SEER - no gas available REP113	($7,347)	0.57	($2,518)	0.77	($2,546)	0.77	$1,427	1.20
14	Air Source Heat Pump 16 SEER -gas available REP127	($8,537)	0.50	($1,328)	0.87	($2,546)	0.77	$2,617	1.44
15	Air Source Heat Pump 18 SEER - gas available REP129	($2,249)	0.46	$127	1.05	($1,032)	0.73	$1,450	2.04
16	Air Source Heat Pump 18 SEER - no gas available REP115	($2,074)	0.51	($48)	0.98	($1,032)	0.73	$1,275	1.81
17	Appliance Recycling Freezers ARC102	$84,943	5.32	($298)	1.00	$63,369	2.69	$63,612	2.71
18	Appliance Recycling Refrigerators ARC101	$385,674	5.90	($3,125)	0.99	$269,452	2.67	$268,064	2.64
19	Attic Insulation V IQW112	$3,288	N/A	($13,850)	0.35	($9,061)	0.46	($9,061)	0.46
20	Audit Recommendations IQW V IQW114	$11,374	N/A	($40,699)	0.29	($29,325)	0.36	($29,325)	0.36
21	Audit Recommendations V HEA116	$28,561	N/A	($69,232)	0.35	($44,098)	0.45	($44,098)	0.45
22	Bathroom Aerator IQW V IQW103	$2,874	N/A	($615)	0.90	$3,125	2.21	$3,125	2.21
23	Bathroom Aerator V HEA112	$37,299	N/A	$3,890	1.06	$46,598	3.48	$46,598	3.48
24	Central Air Conditioner 16 SEER REP 116	($21,517)	0.75	($19,160)	0.73	($4,056)	0.93	$3,801	1.08
25	Central Air Conditioner 18 SEER REP 117	($40,415)	0.68	($11,391)	0.89	($19,244)	0.83	$28,384	1.43
26	CFL 0-15W RLT104	$611,084	3.01	($105,148)	0.84	$300,024	2.27	$347,738	2.85
27	CFL 16-20W RLT105	$619,795	3.46	($77,706)	0.87	$320,977	2.55	$360,400	3.15
28	CFL 21W or Greater RLT106	$591,307	4.09	($55,275)	0.90	$314,606	2.85	$344,554	3.46
29	Compact Fluorescent Lamps V HEA101	$309,769	N/A	($390,021)	0.45	($80,547)	0.80	($80,547)	0.80
30	Compact Fluorescent Lamps IQW V IQW101	$69,004	N/A	($127,952)	0.38	($49,613)	0.62	($49,613)	0.62
31	Dual Fuel Air Sourc Heat Pump 16 SEER REP128	($8,537)	0.50	($1,328)	0.87	($2,546)	0.77	$2,617	1.44
32	Duct Sealing Electric Heat Pump REP108	$20,945	1.89	$5,993	1.10	$38,174	2.27	$36,074	2.13
33	Duct Sealing Electric Resistive Furnace REP109	$10,758	4.42	($1,045)	0.95	$13,411	2.65	$13,131	2.56
34	Duct Sealing Gas Heating with A/C REP107	$1,482	1.02	$49,405	1.46	$77,922	1.99	$101,547	2.84
35	Ductless Heat Pump 17 SEER 9.5 HSPF REP123	$2,469	2.84	($1,590)	0.73	$1,603	1.61	$1,628	1.63
36	Ductless Heat Pump 19 SEER 9.5 HSPF REP124	$1,819	1.90	($1,508)	0.74	$1,174	1.37	$1,735	1.67
37	Ductless Heat Pump 21 SEER 10.0 HSPF REP125	$790	1.59	($904)	0.71	$391	1.21	$765	1.51
38	Ductless Heat Pump 23 SEER 10.0 HSPF REP126	$461	1.27	($869)	0.73	$165	1.08	$808	1.54

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
39	Duel Fuel Air Source Heat Pump 18 SEER REP130	($2,249)	0.46	$127	1.05	($1,032)	0.73	$1,450	2.04
40	ECM HVAC Motor REP118	$9,831	1.11	($49,672)	0.56	($17,936)	0.78	($8,311)	0.88
41	Energy Star Ceiling Fans RLT112	($165)	0.74	($59)	0.84	($29)	0.91	$172	2.26
42	Energy Star Fixtures RLT111	$4,481	1.15	($3,400)	0.88	$8,869	1.54	$15,622	2.63
43	Energy Star Reflector CFL V RLT102	$4,738	1.14	($10,011)	0.65	($1,997)	0.90	$8,065	1.78
44	Energy Star Reflector LED V RLT103	$4,345	1.72	($1,530)	0.87	$5,336	2.01	$7,749	3.70
45	Energy Star Specialty CFL V RLT101	$4,738	1.14	($10,011)	0.65	($1,997)	0.90	$8,065	1.78
46	Furnace Filter Whistle IQW V IQW106	$20,061	N/A	$3,847	1.09	$33,063	3.59	$33,063	3.59
47	Gold Star HERS =<67 All Electric RNC105	$524	1.04	($8,690)	0.71	($1,425)	0.94	$7,088	1.49
48	Gold Star HERS =<67 Electric RNC102	$25,046	2.59	($19,160)	0.78	$24,432	1.55	$26,821	1.64
49	Heat Pump Water Heater REP103	$19,345	1.72	($19,604)	0.74	$8,378	1.18	$21,083	1.62
50	Kitchen Aerator IQW V IQW102	$1,848	N/A	($592)	0.86	$1,812	1.97	$1,812	1.97
51	Kitchen Aerator V HEA111	$37,299	N/A	$3,140	1.05	$45,848	3.35	$45,848	3.35
52	LED 13W RLT109	($1,754)	0.95	($5,037)	0.87	$4,357	1.14	$21,940	2.68
53	LED 22W RLT110	$8,841	1.38	$485	1.01	$18,092	1.90	$29,324	4.29
54	LED 7W RLT107	($2,968)	0.78	($2,138)	0.82	($1,314)	0.88	$5,270	2.11
55	LED 9W RLT108	($5,610)	0.75	($4,383)	0.77	($3,977)	0.78	$6,693	1.87
56	LF Showerhead (Whole House) IQW V IQW104	$18,274	N/A	($10,072)	0.75	$10,674	1.53	$10,674	1.53
57	LF Showerhead (Whole House) V HEA113	$99,709	N/A	($36,798)	0.80	$62,816	1.76	$62,816	1.76
58	Opower OPO101	$487,718	N/A	($188,368)	0.79	$299,349	1.73	$299,349	1.73
59	Pipe Wrap (10', 3/4" Wall) IQW V IQW105	$12,656	N/A	$1,510	1.05	$19,942	3.21	$19,942	3.21
60	Pipe Wrap (5', 3/4" Wall) V HEA114	$28,728	N/A	($6,586)	0.90	$30,232	2.10	$30,232	2.10
61	Platinum Star- EPAct Tax Credit All Electric RNC106	$591	1.13	($3,351)	0.71	($165)	0.98	$2,776	1.50
62	Platinum Star- EPAct Tax Credit Electric RNC103	$10,104	1.60	($12,332)	0.78	$9,998	1.29	$17,159	1.62
63	Pool Heater REP111	$9,209	1.31	($3,752)	0.93	$12,595	1.37	$27,184	2.40
64	programmable thermostat REP104	$37,956	4.10	$30,849	1.41	$78,387	3.90	$81,187	4.36
65	Refrigerator Replacement IQW V IQW113	$195,980	N/A	($51,141)	0.91	$245,594	1.98	$245,594	1.98
66	Siver Star HERS =<75 All Electric RNC104	$3,935	2.61	($4,059)	0.72	$2,951	1.40	$3,588	1.53
67	Siver Star HERS =<75 Electric RNC101	$10,658	3.15	($7,321)	0.79	$10,766	1.65	$11,274	1.71
68	Smart programmable thermostat REP120	$54,240	2.55	$62,384	1.46	$135,466	3.19	$145,966	3.83
69	Variable Speed Pool Pump REP110	$6,147	1.12	$48,252	1.58	$66,439	2.02	$87,439	2.99
70	Water Heater Tank Wrap HEA117	$31,284	N/A	($35,875)	0.56	($4,620)	0.91	($4,620)	0.91

Measures with a benefit-cost ration of 0.00 indicates no direct technology costs are applied.

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
1	Anti Sweat - Cooler V CDI101	$53,689	2.18	($39,109)	0.70	$34,169	1.61	$34,169	1.61
2	Anti Sweat - Freezer V CDI102	$33,647	3.96	($7,383)	0.88	$38,540	3.14	$38,540	3.14
3	Barrel Wraps (Inj Mold Only) CIP202	$5,727	6.73	$206	1.03	$5,561	4.57	$5,861	5.65
4	CFL 16-20W Fixture 1 Lamp CIE142	$5,798	2.43	$678	1.06	$8,088	3.09	$10,178	6.69
5	CFL 16-20W Fixture 2 Lamp CIE145	$15,079	4.25	$1,355	1.06	$18,962	4.81	$20,355	6.69
6	CFL 21W+ Fixture 1 Lamp CIE143	$4,265	3.10	$487	1.07	$5,672	3.79	$6,601	7.00
7	CFL 21W+ Fixture 2 Lamp CIE146	$10,271	5.42	$974	1.07	$12,738	5.78	$13,202	7.00
8	CFL Fixture, Direct Install, 18 Watt, Exterior V CDI103	$3,376	N/A	($1,047)	0.86	$3,561	2.35	$3,561	2.35
9	CFL Fixture, Direct Install, 36 Watt, Interior V CDI104	$17,933	N/A	($931)	0.97	$23,544	3.51	$23,544	3.51
10	CFL screw-in: <30W V CDI105	$38,152	N/A	($15,939)	0.76	$24,794	1.94	$24,794	1.94
11	CFL <15W Fixture 1 Lamp CIE141	$2,655	1.65	$295	1.04	$4,295	2.17	$6,617	5.91
12	CFL <15W Fixture 2 Lamp CIE144	$8,794	2.89	$590	1.04	$11,376	3.50	$13,234	5.91
13	Clothes Washer CEE Tier 2 CIP244	($139)	0.71	($21)	0.94	($53)	0.87	$267	4.22
14	Clothes Washer CEE Tier 3 CIP245	($258)	0.57	($31)	0.92	($157)	0.69	$257	3.76
15	Clothes Washer ENERGY STAR/CEE Tier 1 CIP243	($10)	0.94	($5)	0.97	$25	1.16	$138	4.80
16	Cooler - Glass Door 15-30 vol CIP224	$297	3.39	$3	1.01	$361	3.79	$433	8.54
17	Cooler - Glass Door 30-50 vol CIP225	$435	6.30	$7	1.01	$503	5.91	$539	9.05
18	Cooler - Glass Door <15 vol CIP223	$220	4.07	($5)	0.99	$254	4.28	$286	7.32
19	Cooler - Glass Door >50 vol CIP226	$753	10.18	$26	1.03	$869	7.88	$900	10.39
20	Cooler - Reach-In Electronically Commutated (EC) Motor CIP238	$1,773	4.55	($118)	0.96	$2,081	4.87	$2,181	5.99
21	Cooler - Solid Door 15-30 vol CIP220	$149	1.60	($29)	0.94	$202	1.90	$346	5.27
22	Cooler - Solid Door 30-50 vol CIP221	$361	5.40	$2	1.00	$417	5.30	$452	8.37
23	Cooler - Solid Door <15 vol CIP219	$91	2.28	($14)	0.92	$104	2.54	$136	4.84
24	Cooler - Solid Door >50 vol CIP222	$576	8.03	$13	1.02	$663	6.87	$693	9.42
25	Cooler - Walk-In Electronically Commutated (EC) Motor CIP235	$1,462	4.90	($100)	0.96	$1,703	5.13	$1,778	6.27
26	Cooler Anti-Sweat Heater Controls - Conductivity-Based CIP216	$239	2.19	$19	1.04	$334	2.76	$444	6.58
27	Cooler Anti-Sweat Heater Controls - Humidity-Based CIP215	$28	1.19	$2	1.01	$74	1.56	$169	5.62
28	Cooler Controller - occupancy sensor V CDI106	$16,843	6.91	($1,002)	0.97	$21,128	4.18	$21,840	4.68
29	Delamping, T12 to T8, 4' V CDI108	$59,889	N/A	$16,927	1.18	$98,666	9.71	$98,666	9.71
30	Delamping, T12 to T8, 8' V CDI109	$24,811	N/A	$7,020	1.18	$40,883	9.71	$40,883	9.71
31	Delamping, >=400 Watt Fixture V CDI107	$48,989	N/A	$13,958	1.18	$80,821	9.71	$80,821	9.71
32	Demand Controlled Ventilation - CO CIP165	$961	4.34	$383	1.25	$1,589	6.14	$1,704	9.79
33	Demand Controlled Ventilation - CO2 CIP164	$1,922	4.34	$766	1.25	$3,177	6.14	$3,407	9.79
34	Door Closers for Cooler CDI142	$16,426	2.07	($16,277)	0.61	$2,205	1.09	$6,033	1.31

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
35	Door Closers for Freezer CDI143	$45,048	3.94	($23,049)	0.73	$26,959	1.78	$30,788	2.00
36	EC Motor Reach-in V CDI110	$8,130	2.14	($3,488)	0.84	$9,163	2.03	$10,939	2.53
37	EC Motor Walk-in V CDI111	$8,309	1.70	($6,787)	0.75	$6,664	1.48	$9,624	1.88
38	EDA - Lighting Power Density Reduction CNC101	$41,883	1.24	$3,144	1.01	$124,901	1.54	$260,146	3.76
39	EDA - Non Lighting Measures CNC102	($41,916)	0.73	($49,757)	0.72	($61,110)	0.68	$69,363	2.18
40	Electric Chiller - Air cooled, with condenser CIP156	$150	2.81	$125	1.42	$347	5.40	$383	9.92
41	Electric Chiller - Air cooled, without condenser CIP157	($25)	0.40	$14	1.66	$0	1.01	$28	5.96
42	Electric Chiller - Water Cooled, Centrifugal 150-300 tons CIP162	$28	1.60	$30	1.32	$83	3.04	$105	6.59
43	Electric Chiller - Water Cooled, Centrifugal <150 tons CIP161	$24	1.39	$37	1.34	$94	2.73	$129	7.59
44	Electric Chiller - Water Cooled, Centrifugal >300 tons CIP163	$76	2.10	$54	1.29	$175	3.80	$201	6.38
45	Electric Chiller - Water Cooled, Rotary Screw 150-300 tons CIP159	$45	2.51	($13)	0.87	$55	2.98	$64	4.38
46	Electric Chiller - Water Cooled, Rotary Screw <150 tons CIP158	$29	1.69	$41	1.46	$94	3.54	$112	7.05
47	Electric Chiller - Water Cooled, Rotary Screw >300 tons CIP160	$53	3.52	$31	1.33	$104	6.07	$106	6.64
48	Electric Chiller Tune-up - Air cooled, with condenser CIP172	$24	3.17	$7	1.18	$30	3.34	$35	5.36
49	Electric Chiller Tune-up - Water Cooled, Centrifugal 150-300 tons CIP178	$9	1.82	$1	1.06	$11	2.01	$16	3.76
50	Electric Chiller Tune-up - Water Cooled, Centrifugal >300 tons CIP179	$8	1.70	$1	1.04	$9	1.88	$14	9.92
51	Electric Chiller Tune-up - Water Cooled, Rotary Screw 150-300 tons CIP175	$10	1.89	$1	1.03	$11	2.02	$16	5.96
52	Electric Chiller Tune-up - Water Cooled, Rotary Screw >300 tons CIP176	$8	1.76	$1	1.07	$11	1.98	$15	7.59
53	ENERGY STAR CEE Tier 1 Window\Sleeve\Room AC < 14,000 BTUH CIP118	$6	1.15	$33	1.63	$51	2.45	$75	7.87
54	ENERGY STAR CEE Tier 2 Window\Sleeve\Room AC < 14,000 BTUH CIP170	($82)	0.34	$54	2.12	($0)	1.00	$75	8.19
55	ENERGY STAR CEE Tier 2 Window\Sleeve\Room AC >= 14,000 BTUH CIP171	($181)	0.27	$101	2.29	($25)	0.88	$75	11.68
56	ENERGY STAR Commercial Dishwasher - Door Type, High Temp CIP249	$4,292	18.17	$501	1.09	$5,552	12.13	$5,502	11.03
57	ENERGY STAR Commercial Dishwasher - Multi-Tank Conveyor, Low Temp CIP252	$5,646	12.64	$884	1.11	$8,216	11.86	$8,229	12.06
58	ENERGY STAR Commercial Dishwasher - Under Counter, High Temp CIP247	$1,580	4.16	$12	1.00	$1,769	4.17	$1,994	6.99
59	ENERGY STAR Commercial Dishwasher - Under Counter, Low Temp CIP246	$119	1.45	($45)	0.89	$140	1.59	$277	3.75
60	ENERGY STAR Commercial Fryer CIP103	$78	1.31	$22	1.06	$175	1.79	$325	5.60
61	ENERGY STAR Commercial Hot Holding Cabinets Full Size CIP104	$1,195	3.15	($1)	1.00	$1,443	3.60	$1,637	5.53
62	ENERGY STAR Commercial Hot Holding Cabinets Half Size CIP105	$101	1.18	($34)	0.95	$227	1.47	$546	4.32
63	ENERGY STAR Commercial Hot Holding Cabinets Three Quarter Size CIP106	$432	1.78	($37)	0.97	$581	2.15	$850	4.61

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
64	ENERGY STAR Commercial Ice Machine < 500 lb/day harvest rate CIP114	($123)	0.54	($42)	0.73	($110)	0.51	$55	1.94
65	ENERGY STAR Commercial Ice Machine >=1000 lb/day harvest rate CIP116	($471)	0.53	($91)	0.84	($355)	0.58	$323	3.01
66	ENERGY STAR Commercial Ice Machine >=500 and <1000 lb/day harvest rate CIP115	($4,241)	0.43	($685)	0.80	($3,406)	0.45	$1,659	2.54
67	ENERGY STAR Commercial Steam Cookers 3 Pan CIP107	$1,123	1.32	$36	1.01	$2,215	1.72	$4,265	5.14
68	ENERGY STAR Commercial Steam Cookers 4 Pan CIP108	$2,419	1.69	$4	1.00	$3,575	2.13	$5,375	4.96
69	ENERGY STAR Commercial Steam Cookers 5 Pan CIP109	$2,214	2.27	$64	1.01	$2,934	2.79	$3,709	5.28
70	ENERGY STAR Commercial Steam Cookers 6 Pan CIP110	$2,957	2.69	$72	1.01	$3,743	3.22	$4,393	5.23
71	ENERGY STAR Convection Oven CIP111	$564	2.01	$16	1.01	$779	2.52	$1,049	5.31
72	ENERGY STAR Griddles CIP112	$1,348	2.29	$65	1.02	$1,810	2.84	$2,296	5.61
73	ENERGY STAR Window\Sleeve\Room AC < 14,000 BTUH CIP117	$24	2.20	$35	1.70	$67	4.53	$77	9.64
74	ENERGY STAR Window\Sleeve\Room AC >= 14,000 BTUH CIP119	$47	3.35	$58	1.75	$114	6.57	$123	11.69
75	Faucet Aerators-electric V CDI112	$2,777	N/A	($235)	0.95	$3,378	4.33	$3,378	4.33
76	Fluorescent Exit Sign To LED Exit Sign CIE135	$40,257	2.47	($10,427)	0.87	$44,602	2.78	$48,247	3.25
77	Freezer - Glass Door 15-30 vol CIP232	$611	8.36	($28)	0.97	$657	6.79	$648	6.31
78	Freezer - Glass Door 30-50 vol CIP233	$1,242	15.97	($6)	1.00	$1,366	9.56	$1,332	7.90
79	Freezer - Glass Door <15 vol CIP231	$351	5.94	($21)	0.96	$378	5.44	$385	5.92
80	Freezer - Glass Door >50 vol CIP234	$2,357	12.58	$8	1.00	$2,625	8.63	$2,612	8.33
81	Freezer - Reach-In Electronically Commutated (EC) Motor CIP237	$228	5.57	($13)	0.96	$266	5.65	$276	6.84
82	Freezer - Solid Door 15-30 vol CIP228	$665	9.01	($23)	0.97	$720	7.12	$711	6.64
83	Freezer - Solid Door 30-50 vol CIP229	$872	11.50	($34)	0.97	$932	8.10	$899	6.45
84	Freezer - Solid Door <15 vol CIP227	$262	4.68	($28)	0.93	$273	4.49	$280	4.92
85	Freezer - Solid Door >50 vol CIP230	$1,497	8.36	($58)	0.97	$1,620	6.81	$1,608	6.53
86	Freezer - Walk-In Electronically Commutated (EC) Motor CIP236	$916	8.33	($76)	0.94	$1,020	7.16	$1,020	7.16
87	Freezer Anti-Sweat Heater Controls - Conductivity-Based CIP218	$362	4.62	$23	1.04	$443	4.98	$473	6.82
88	Freezer Anti-Sweat Heater Controls - Humidity-Based CIP217	$249	2.66	($17)	0.96	$291	3.01	$336	4.37
89	Halogen 120W x3 To CMH 150W - Retrofit CIE134	$14,364	6.00	$2,071	1.10	$19,539	6.90	$19,923	7.80
90	Halogen 120W x3 To CMH 150W - Turnover CIE115	$15,464	5.77	$3,054	1.13	$22,016	6.90	$23,168	9.97
91	Halogen 50W x2 To CMH 20W - Retrofit CIE129	$2,561	1.62	$539	1.07	$4,881	2.32	$7,245	6.41
92	Halogen 50W x2 To CMH 20W - Turnover CIE110	$2,706	1.58	$787	1.09	$5,500	2.32	$8,344	7.28
93	Halogen 50W x2 To MH 20W Track - Retrofit CIE126	$618	1.40	$186	1.07	$1,418	2.05	$2,348	6.59
94	Halogen 50W x2 To MH 20W Track - Turnover CIE107	$3,036	1.40	$912	1.07	$6,959	2.05	$11,527	6.59
95	Halogen 65W x3 To CMH 50W - Retrofit CIE131	$9,293	4.06	$1,395	1.09	$13,093	5.16	$14,083	7.53

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
96	Halogen 65W x3 To CMH 50W - Turnover CIE112	$9,930	3.90	$2,112	1.13	$14,752	5.16	$16,408	9.68
97	Halogen 75W x2 To CMH 39W - Retrofit CIE130	$4,622	2.27	$739	1.07	$7,264	3.15	$9,049	6.70
98	Halogen 75W x2 To CMH 39W - Turnover CIE111	$5,963	2.27	$954	1.07	$9,372	3.15	$11,676	6.70
99	Halogen 75W x2 To MH 39W Track - Retrofit CIE127	$1,441	1.94	$275	1.08	$2,448	2.75	$3,280	6.79
100	Halogen 75W x2 To MH 39W Track - Turnover CIE108	$8,513	1.94	$1,624	1.08	$14,466	2.75	$19,380	6.79
101	Halogen 75W x3 To CMH 70W - Retrofit CIE132	$8,661	4.27	$1,185	1.09	$12,014	5.33	$12,739	7.21
102	Halogen 75W x3 To CMH 70W - Turnover CIE113	$10,456	4.06	$2,249	1.13	$15,502	5.33	$17,158	9.91
103	Halogen 75W x3 To MH 70W Track - Retrofit CIE128	$2,627	2.83	$433	1.09	$3,936	3.84	$4,589	7.28
104	Halogen 75W x3 To MH 70W Track - Turnover CIE109	$15,521	2.83	$2,559	1.09	$23,256	3.84	$27,117	7.28
105	Halogen 90W x3 To CMH 100W - Retrofit CIE133	$11,327	4.94	$1,481	1.09	$15,438	5.94	$15,981	7.19
106	Halogen 90W x3 To CMH 100W - Turnover CIE114	$12,043	4.72	$2,389	1.13	$17,394	5.94	$18,726	9.56
107	Heat Pump Water Heater 10-50 MBH CIP255	$27,103	3.71	$2,908	1.07	$37,311	4.65	$40,311	6.57
108	HID 101W-175W To T5 Garage 2 Lamp CIE159	($6,247)	0.73	($8,549)	0.52	($10,409)	0.47	($1,040)	0.90
109	HID 176W+ To T5 Garage 3 Lamp CIE160	$834	1.07	($6,812)	0.47	($3,827)	0.61	($1,792)	0.77
110	HID 75W-100W To T5 Garage 1 Lamp CIE158	($12,753)	0.46	($4,919)	0.55	($13,185)	0.31	$87	1.01
111	HID To Induction Lamp and Fixture 55-100W CIE204	($616)	0.47	$55	1.08	($245)	0.75	$574	4.95
112	HID To Induction Lamp and Fixture >100W CIE205	($27,147)	0.36	$3,072	1.16	($13,089)	0.62	$18,771	7.30
113	HID >400W to Exterior LED or Induction CIP199	$17	2.10	$5	1.13	$30	3.15	$38	7.61
114	HID >400W to Garage LED or Induction CIP200	$4	2.10	$1	1.13	$8	3.15	$10	7.61
115	High Efficiency Pumps - 1.5hp CIP203	$103	1.29	$45	1.08	$283	1.93	$503	6.85
116	High Efficiency Pumps - 10hp CIP208	$1,846	12.12	$395	1.16	$2,586	11.00	$2,599	11.58
117	High Efficiency Pumps - 15hp CIP209	$2,339	9.00	$541	1.17	$3,350	9.38	$3,444	12.26
118	High Efficiency Pumps - 20hp CIP210	$4,073	5.79	$942	1.16	$5,945	7.03	$6,305	11.07
119	High Efficiency Pumps - 2hp CIP204	$162	1.92	$27	1.07	$271	2.70	$361	6.23
120	High Efficiency Pumps - 3hp CIP205	$471	3.69	$99	1.13	$701	4.92	$781	8.90
121	High Efficiency Pumps - 5hp CIP206	$1,031	7.05	$226	1.15	$1,477	8.00	$1,533	10.92
122	High Efficiency Pumps - 7.5hp CIP207	$1,579	7.34	$370	1.17	$2,284	8.27	$2,384	12.09
123	Incandescent To CFL 16-20W Screw-In CIE139	$5,023	10.61	($532)	0.91	$3,837	3.82	$3,906	4.03
124	Incandescent To CFL 21W+ Screw-In CIE140	$2,230	8.68	($369)	0.86	$1,593	3.50	$1,535	3.21
125	Incandescent To CFL <15W Screw-In CIE138	$7,100	7.80	($960)	0.89	$5,262	3.41	$5,402	3.64
126	Incandescent Traffic Signal To LED Traffic Signal Pedestrian 12" CIE137	$21,726	2.79	($3,430)	0.91	$21,988	2.81	$28,671	6.25
127	Incandescent Traffic Signal To LED Traffic Signal Round 8" Red CIE136	$4,272	1.59	($1,197)	0.91	$4,931	1.75	$8,940	4.45
128	Industrial Request for Proposals - Elec CUS109	$8,218	1.75	($2,373)	0.91	$10,428	1.75	$17,627	3.63
129	Industrial Staffing Grants - Elec CUS108	$8,218	1.75	($2,373)	0.91	$10,428	1.75	$17,627	3.63
130	Large Industrial Custom Measure - Non	$116,770		($30,687)		$145,242		$227,929	

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
	Lighting CUS101		1.89		0.91		1.86		3.63
131	LED A-Line 8-12W CIE162	$10,449	1.99	($2,431)	0.89	$9,009	1.87	$13,755	3.47
132	LED Decoratives 2-4W CIE161	$140	1.23	($172)	0.78	$56	1.10	$335	2.24
133	LED Exterior Wall-Pack 30W-75W CIE174	$2,902	1.36	$366	1.03	$5,720	1.81	$10,512	5.63
134	LED Exterior Wall-Pack 75W+ CIE175	$7,841	1.65	$1,290	1.06	$13,129	2.21	$20,318	6.56
135	LED Exterior Wall-Pack <30W CIE173	$6,377	2.21	$415	1.03	$8,766	2.77	$11,304	5.69
136	LED Fixture <250W, Replacing 400W HID, HighBay V CDI113	$13,142	1.59	($9,928)	0.79	$11,749	1.46	$17,309	1.87
137	LED for Walk in Cooler V CDI114	$10,734	1.19	($33,049)	0.61	($10,205)	0.83	$4,003	1.09
138	LED for Walk in Freezer V CDI115	$5,749	1.20	($16,378)	0.62	($4,388)	0.86	$2,716	1.12
139	LED MR16 4-7W CIE166	$473	1.22	($560)	0.80	$317	1.17	$1,220	2.27
140	LED Open Sign V CDI116	$27,587	4.88	$3,027	1.06	$41,327	4.26	$43,103	4.96
141	LED Outdoor Decorative Post 30W-75W CIE168	$2,902	1.36	$366	1.03	$5,720	1.81	$10,512	5.63
142	LED Outdoor Decorative Post 75W+ CIE169	$7,841	1.65	$1,290	1.06	$13,129	2.21	$20,318	6.56
143	LED Outdoor Decorative Post <30W CIE167	$6,377	2.21	$415	1.03	$8,766	2.77	$11,304	5.69
144	LED PAR 20 7-9W CIE163	$928	1.44	($200)	0.94	$1,123	1.58	$2,292	4.03
145	LED PAR 30 10-13W CIE164	$5,141	1.61	($611)	0.96	$6,093	1.78	$10,756	4.42
146	LED PAR 38 10-21W CIE165	$21,522	2.23	($2,793)	0.93	$21,858	2.30	$28,851	3.93
147	LED Parking Garage/Canopy 30W-75W CIE171	$1,921	1.36	$243	1.03	$3,786	1.81	$6,959	5.63
148	LED Parking Garage/Canopy 75W+ CIE172	$5,191	1.65	$854	1.06	$8,691	2.21	$13,450	6.56
149	LED Parking Garage/Canopy <30W CIE170	$4,274	2.21	$278	1.03	$5,875	2.77	$7,576	5.69
150	LED Recessed Downlight V CDI117	$19,708	2.46	($1,564)	0.97	$28,759	2.64	$32,311	3.31
151	LED, Exit Sign, Retrofit V CDI118	$13,304	N/A	($7,931)	0.74	$11,833	2.13	$11,833	2.13
152	LED, Refrigerated Case, Replaces T12 or T8 V CDI119	$29,418	1.30	($74,323)	0.55	($18,547)	0.83	$6,317	1.07
153	LEDs: 8-12W V CDI122	$30,516	N/A	($7,788)	0.86	$29,919	2.54	$29,919	2.54
154	LEDs: 8-12W V CDI123	$17,175	N/A	($4,383)	0.86	$16,840	2.54	$16,840	2.54
155	LEDs: MR16 track V CDI124	$36,993	N/A	($6,825)	0.90	$38,887	2.86	$38,887	2.86
156	LEDs: MR16 track V CDI125	$20,821	N/A	($3,841)	0.90	$21,887	2.86	$21,887	2.86
157	LEDs: >12W Flood V CDI120	$51,786	N/A	($7,940)	0.91	$56,050	3.02	$56,050	3.02
158	LEDs: >12W Flood V CDI121	$19,420	N/A	($2,978)	0.91	$21,019	3.02	$21,019	3.02
159	Low Flow Pre-Rinse Sprayer - Electric CIP242	$3,052	35.87	($52)	0.98	$2,735	6.90	$2,742	7.01
160	Market Segment Programs - Elec CUS105	$8,218	1.75	($2,373)	0.91	$10,428	1.75	$17,627	3.63
161	MH 1000W Pulse Start To T5 46" 10 Lamp HO - Turnover CIE105	$132,715	8.86	$21,253	1.12	$179,716	9.00	$179,153	8.78
162	MH 1000W Pulse Start To T5 46" 12 Lamp HO - Turnover CIE106	$84,985	6.97	$10,884	1.09	$113,138	7.59	$112,663	7.38
163	MH 1000W To T5 46" 10 Lamp HO - Retrofit CIE124	$132,715	8.86	$21,253	1.12	$179,716	9.00	$179,153	8.78
164	MH 1000W To T5 46" 12 Lamp HO -	$56,388		$7,222		$75,068		$74,753	

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
	Retrofit CIE125		6.97		1.09		7.59		7.38
165	MH 1000W To T8VHO 48" 8 Lamp (2 fixtures) CIP187	$4,072	6.43	($183)	0.96	$3,880	4.86	$3,855	4.74
166	MH 150W Pulse Start To T5 46" 2 Lamp HO - Turnover CIE101	$5,637	1.24	$2,653	1.08	$17,219	1.83	$32,224	6.73
167	MH 175W To T5 46" 2 Lamp HO - Retrofit CIE120	$17,621	1.74	$2,785	1.06	$30,921	2.45	$43,557	6.05
168	MH 175W To T5 46" 3 Lamp HO - Retrofit CIE121	($6,991)	0.70	($3,617)	0.81	($4,156)	0.79	$8,480	2.21
169	MH 200W Pulse Start To T5 46" 3 Lamp HO - Turnover CIE102	($131)	0.99	$1,153	1.04	$8,998	1.44	$24,003	5.58
170	MH 200W To LED High Bay 139W CIE118	$317	1.04	($694)	0.92	$1,096	1.16	$5,740	3.70
171	MH 250W To LED High Bay 175W CIE119	$12,997	1.34	($4,175)	0.92	$16,097	1.46	$37,432	3.78
172	MH 250W To LED Low Bay 85 W3 CIE116	$10,051	2.30	($1,166)	0.94	$10,264	2.37	$13,360	4.03
173	MH 250W To T8VHO 48" 4 Lamp CIP184	$2,799	1.93	($496)	0.92	$2,720	1.95	$4,120	3.82
174	MH 320W Pulse Start To T5 46" 4 Lamp HO - Turnover CIE103	$47,012	2.39	$9,667	1.10	$75,276	3.37	$93,276	7.79
175	MH 350W Pulse Start To T5 46" 6 Lamp HO - Turnover CIE104	$1,046	1.06	($1,009)	0.95	$5,628	1.39	$14,628	3.72
176	MH 400W To T5 46" 4 Lamp HO - Retrofit CIE122	$108,061	4.20	$12,814	1.08	$147,878	5.21	$155,753	6.72
177	MH 400W To T5 46" 6 Lamp HO - Retrofit CIE123	$36,116	2.07	$3,997	1.05	$56,539	2.83	$72,289	5.78
178	MH 400W To T8VHO 48" 6 Lamp CIP185	$5,930	2.98	($387)	0.96	$5,849	2.86	$7,049	4.62
179	MH 400W To T8VHO 48" 8 Lamp CIP186	$966	2.29	($151)	0.92	$911	2.24	$1,211	3.77
180	Network PC Power Management Software CIP214	$306	3.55	($97)	0.78	$186	2.21	$252	3.89
181	Night Covers V CDI126	$5,769	1.73	($6,168)	0.64	$651	1.06	$2,640	1.31
182	No controls To Ceiling-Mounted Occupancy Sensors CIE180	$50,987	4.48	($10,188)	0.85	$43,051	3.54	$48,110	5.04
183	No controls To Ceiling-Mounted Occupancy Sensors >500W Connected CIP190	$5,164	8.82	($724)	0.88	$4,510	5.46	$4,638	6.25
184	No controls To Central Lighting Controls (Timeclocks) CIE185	$119	1.10	($395)	0.71	($55)	0.95	$591	2.60
185	No controls To Central Lighting Controls (Timeclocks) >500W Connected CIP195	$49	1.95	($20)	0.81	$38	1.77	$69	4.83
186	No controls To Fixture Mounted Daylight Dimming Sensors CIE183	$916	1.66	($20)	0.99	$1,153	1.90	$1,850	4.15
187	No controls To Fixture Mounted Daylight Dimming Sensors >500W Connected CIP193	$10,648	11.65	$1,487	1.12	$12,210	7.91	$12,210	7.91
188	No controls To Fixture Mounted Occupancy Sensors CIE181	($1,238)	0.70	($801)	0.74	($1,233)	0.65	$1,431	2.65
189	No controls To Fixture Mounted Occupancy Sensors >500W Connected CIP191	$9,148	4.66	($1,448)	0.88	$8,075	3.72	$9,275	6.25
190	No controls To LED Case Lighting Sensor Controls CIP196	$2,123	2.63	$99	1.03	$2,446	2.85	$3,186	6.44
191	No controls To Remote-Mounted Daylight Dimming Sensors CIE182	$2,597	4.55	$292	1.08	$3,001	4.53	$3,249	6.38
192	No controls To Remote-Mounted Daylight Dimming Sensors >500W Connected CIP192	$1,293	8.96	$186	1.12	$1,496	6.97	$1,526	7.91
193	No controls To Switching Controls for Multi-Level Lighting CIE184	($5,195)	0.32	($248)	0.90	($3,936)	0.37	$1,622	3.23
194	No controls To Switching Controls for Multi-Level Lighting >500W Connected CIP194	$771	2.13	$122	1.08	$1,015	2.52	$1,463	7.63

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
195	No controls To Wall-Mounted Occupancy Sensors CIE179	$25,210	3.71	($6,241)	0.83	$20,488	3.02	$23,505	4.30
196	No controls To Wall-Mounted Occupancy Sensors >500W Connected CIP189	$5,404	13.87	($724)	0.88	$4,702	6.74	$4,638	6.25
197	Occupancy Sensor, Wall Mount, >200 Watts V CDI128	$46,730	3.19	($16,159)	0.83	$42,841	2.26	$48,172	2.68
198	Occupancy Sensor, Wall Mount, <=200 Watts V CDI127	$6,114	2.15	($4,027)	0.73	$3,842	1.54	$5,176	1.89
199	Outside Air Economizer with Dual-Enthalpy Sensors CIP167	($172)	0.57	($25)	0.90	($109)	0.67	$161	3.49
200	Packaged Terminal Air Conditioner (PTAC) 65,000-135,000 BtuH CIP141	($326)	0.97	$8,588	1.74	$11,611	2.36	$18,111	9.76
201	Packaged Terminal Air Conditioner (PTAC) <65,000 BtuH CIP140	($346)	0.97	$9,198	1.80	$12,198	2.42	$18,698	10.05
202	Packaged Terminal Heat Pump (PTHP) 65,000-135,000 BtuH CIP143	($363)	0.96	$7,591	1.66	$10,572	2.23	$17,072	9.26
203	Packaged Terminal Heat Pump (PTHP) <65,000 BtuH CIP142	($382)	0.96	$8,204	1.71	$11,162	2.30	$17,662	9.55
204	Pellet Dryer Duct Insulation 3in -8in dia CIP201	$839	2.29	($307)	0.80	$553	1.83	$773	2.73
205	Performance Based Industrial Assessments - Elec CUS106	$8,218	1.75	($2,373)	0.91	$10,428	1.75	$17,627	3.63
206	Plug Load Occupancy Sensors CIP212	$262	1.37	($306)	0.70	$87	1.14	$447	2.65
207	Pre-Rinse Spray Valves - ele V CDI129	$6,301	N/A	($1,263)	0.87	$5,890	3.56	$5,890	3.56
208	Programmable Thermostat CDI137	$647,200	N/A	($113,077)	0.91	$621,676	2.28	$621,676	2.28
209	PSMH 1000W To T8VHO 48" 8 Lamp (2 fixtures) CIP197	$5,683	8.58	$1,298	1.17	$8,143	9.10	$8,443	12.96
210	Refrigerated Case Covers CIP239	$250	1.60	($262)	0.62	$24	1.06	$210	1.97
211	Self-Generation Efficiency Improvements - Elec CUS107	$8,218	1.75	($2,373)	0.91	$10,428	1.75	$17,627	3.63
212	Showerheads-electric V CDI130	$3,016	N/A	($231)	0.95	$3,693	4.42	$3,693	4.42
213	Smart Strip Plug Outlet CIP211	($4)	0.98	($29)	0.81	($4)	0.97	$76	2.52
214	Smart Strips CDI138	$11,467	N/A	($35,603)	0.32	($21,432)	0.44	($21,432)	0.44
215	Snack Machine Controller (Non-refrigerated vending) CIP213	$351	1.32	($296)	0.80	$167	1.17	$731	2.64
216	Specialty CFLs: Reflectors V CDI131	$10,774	N/A	($11,491)	0.55	($353)	0.98	($353)	0.98
217	Split System Heat Pump 135,000-240,000 BtuH CIP149	($228)	0.96	$4,336	1.63	$6,096	2.19	$9,896	8.43
218	Split System Heat Pump 240,000-760,000 BtuH CIP150	($4,412)	0.51	$3,369	1.62	$1,382	1.19	$7,782	8.32
219	Split System Heat Pump 65,000-135,000 BtuH CIP148	($127)	0.96	$2,657	1.66	$3,700	2.23	$5,975	9.26
220	Split System Heat Pump <65,000 BtuH CIP147	($19)	0.96	$410	1.71	$558	2.30	$883	9.55
221	Split System Unitary Air Conditioner 135,000-240,000 BtuH CIP153	($129)	0.97	$3,075	1.71	$4,191	2.31	$6,566	8.89
222	Split System Unitary Air Conditioner 240,000-760,000 BtuH CIP154	($5,494)	0.51	$4,791	1.70	$2,332	1.25	$10,332	8.77
223	Split System Unitary Air Conditioner 65,000-135,000 BtuH CIP152	($245)	0.97	$6,441	1.74	$8,708	2.36	$13,583	9.76
224	Split System Unitary Air Conditioner <65,000 BtuH CIP151	($260)	0.97	$6,899	1.80	$9,149	2.42	$14,024	10.05
225	Split System Unitary Air Conditioner >760,000 BtuH CIP155	($14,058)	0.38	$6,711	1.65	($1,651)	0.91	$14,799	7.63
226	Strip Curtains Cooler CDI144	$656	1.01	($36,333)	0.29	($34,476)	0.30	($23,298)	0.39
227	Strip Curtains Freezer CDI145	$86,941	2.62	($64,121)	0.66	$33,008	1.35	$46,464	1.58

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
228	System Study CUS102	$47,415	7.16	($6,819)	0.91	$53,528	4.27	$50,651	3.63
229	T12 18” 1 Lamp To Delamp CIE147	$1,061	N/A	$42	1.04	$1,141	16.44	$1,019	6.19
230	T12 24” 1 Lamp To Delamp CIE148	$6,891	N/A	$482	1.06	$7,630	16.44	$7,016	7.33
231	T12 36” 1 Lamp To Delamp CIE149	$2,000	N/A	$205	1.09	$2,282	16.44	$2,160	8.99
232	T12 46" 1 Lamp To T5 46" 1 Lamp CIE154	$342	1.22	($106)	0.95	$606	1.45	$1,469	4.00
233	T12 46" 2 Lamp To T5 46" 2 Lamp CIE155	$6,104	2.32	($79)	0.99	$7,318	2.66	$9,348	4.94
234	T12 46" 3 Lamp To T5 46" 3 Lamp CIE156	$7,448	3.43	$105	1.01	$8,538	3.69	$9,521	5.35
235	T12 46" 4 Lamp To T5 46" 4 Lamp CIE157	$22,669	4.69	$702	1.02	$25,627	4.72	$26,856	5.74
236	T12 48” 1 Lamp To Delamp CIE150	$71,597	N/A	$7,541	1.09	$81,894	16.44	$77,671	9.15
237	T12 6' To Refrigerated Display Case Lighting 6' LED - Cooler CIP181	($2,341)	0.63	($568)	0.86	($1,692)	0.68	$2,308	2.82
238	T12 6' To Refrigerated Display Case Lighting 6' LED - Freezer CIP183	($1,873)	0.63	($454)	0.86	($1,354)	0.68	$1,846	2.82
239	T12 60” 1 Lamp To Delamp CIE151	$3,282	N/A	$393	1.11	$3,804	16.44	$3,651	10.14
240	T12 72” 1 Lamp To Delamp CIE152	$7,243	N/A	$903	1.11	$8,430	16.44	$8,121	10.51
241	T12 96” 1 Lamp To Delamp CIE153	$60,800	N/A	$8,362	1.12	$71,570	16.44	$69,651	11.63
242	T8 2 Lamp 4' To LED 1 Lamp Linear 4' CIE178	($5,043)	0.80	($1,837)	0.92	($524)	0.98	$14,434	3.38
243	T8 2L 4', 28W, CEE V CDI132	$16,306	1.18	($55,730)	0.56	($25,373)	0.74	($3,171)	0.96
244	T8 3 Lamp 4' To LED 2 Lamp Linear 4' CIE177	($2,105)	0.85	($1,588)	0.88	($1)	1.00	$8,063	2.97
245	T8 3L 4', 28W, CEE V CDI133	$6,935	1.33	($12,528)	0.64	($1,118)	0.95	$4,214	1.23
246	T8 4L 4', 28W, CEE V CDI134	$16,613	1.25	($40,353)	0.60	($11,630)	0.84	$4,946	1.09
247	T8 5' To Refrigerated Display Case Lighting 5' LED - Cooler CIP180	($790)	0.37	($75)	0.85	($619)	0.40	$256	2.64
248	T8 5' To Refrigerated Display Case Lighting 5' LED - Freezer CIP182	($790)	0.37	($75)	0.85	($619)	0.40	$256	2.64
249	T8 6L or T5HO 4L Replacing 400-999 W HID V CDI135	$418,460	2.96	($25,775)	0.97	$564,806	2.87	$618,086	3.48
250	T8 HO 96" 2 Lamp To LED Low Bay 85 W3 CIE117	($1,674)	0.93	($3,754)	0.84	($947)	0.95	$11,873	2.64
251	T8 To 21" Tubular Skylight/Light Tube CIP188	($513)	0.59	$7	1.01	($231)	0.78	$644	4.82
252	T8 U-Tube 2 Lamp 2' To LED U-Tube CIE176	($466)	0.68	($143)	0.87	($255)	0.79	$615	2.81
253	Typical Custom Measure - Lighting CUS103	$167,953	1.52	$16,810	1.02	$368,488	1.96	$605,926	5.11
254	Typical Custom Measure - Non-Lighting CUS104	$102,880	1.26	($88,493)	0.87	$134,708	1.29	$431,727	3.48
255	Vending Machine Occ Sensor - Refrigerated Glass Front Cooler CIE187	$1,682	2.08	($350)	0.90	$1,379	1.86	$2,260	4.11
256	Vending Machine Occ Sensor - Refrigerated Beverage CIE186	$7,920	2.70	($1,040)	0.92	$6,757	2.30	$9,401	4.69
257	Vending Miser V CDI136	$16,535	2.75	($10,318)	0.70	$8,774	1.56	$11,142	1.83
258	VFD CHW Pump 20-100hp - Hospital CIP129	$120,238	37.83	$12,528	1.08	$153,600	14.81	$154,962	16.88
259	VFD CHW Pump 20-100hp - Hotel CIP123	$121,367	38.17	$8,185	1.05	$150,572	14.44	$151,934	16.44
260	VFD CHW Pump 20-100hp - Large Office CIP135	$68,869	22.09	$9,241	1.10	$90,464	12.99	$91,826	15.85
261	VFD CHW Pump <20hp - Hospital	$28,808		$2,407		$36,345		$36,591	

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
	CIE190		21.11		1.06		12.40		13.44
262	VFD CHW Pump <20hp - Hotel CIE195	$14,539	21.30	$682	1.04	$17,809	12.11	$17,932	13.11
263	VFD CHW Pump <20hp - Large Office CIE200	$16,479	12.50	$1,618	1.07	$21,192	10.09	$21,438	11.29
264	VFD Compressor CIE203	$7,653	2.26	($346)	0.98	$10,538	2.86	$13,879	6.97
265	VFD CW Pump 20-100hp - Hospital CIP131	$34,533	11.58	$5,744	1.12	$47,071	10.07	$49,083	16.45
266	VFD CW Pump 20-100hp - Hotel CIP125	($1,330)	0.59	$283	1.13	($173)	0.94	$1,839	3.66
267	VFD CW Pump 20-100hp - Large Office CIP137	$16,492	6.05	$3,448	1.14	$23,755	7.03	$25,767	14.37
268	VFD CW Pump <20hp - Hospital CIE192	$3,405	6.43	$540	1.11	$4,715	7.11	$5,091	13.84
269	VFD CW Pump <20hp - Hotel CIE197	($155)	0.42	($14)	0.89	($105)	0.52	$56	1.96
270	VFD CW Pump <20hp - Large Office CIE202	$1,511	3.41	$299	1.11	$2,267	4.54	$2,643	10.96
271	VFD HW Pump 20-100hp - Hospital CIP130	$101,456	32.07	$15,040	1.12	$134,271	14.66	$135,883	17.53
272	VFD HW Pump 20-100hp - Hotel CIP124	$128,158	40.25	$11,016	1.07	$161,357	14.80	$162,969	17.17
273	VFD HW Pump 20-100hp - Large Office CIP136	$67,034	21.53	$19,781	1.23	$98,908	14.30	$100,520	18.26
274	VFD HW Pump <20hp - Hospital CIE191	$10,579	17.88	$1,369	1.10	$13,871	12.01	$14,058	14.10
275	VFD HW Pump <20hp - Hotel CIE196	$5,735	22.35	$406	1.05	$7,164	12.49	$7,244	14.33
276	VFD HW Pump <20hp - Large Office CIE201	$6,965	12.11	$1,867	1.20	$10,158	11.08	$10,345	13.59
277	VFD Return Fan 20-100hp - Hospital CIP127	$31,961	10.79	$4,648	1.11	$42,994	9.55	$45,106	16.46
278	VFD Return Fan 20-100hp - Hotel CIP121	($34)	0.99	$113	1.03	$1,184	1.42	$3,296	5.78
279	VFD Return Fan 20-100hp - Large Office CIP133	$22,492	7.89	$4,703	1.15	$32,017	8.33	$34,129	16.12
280	VFD Return Fan <20hp - Hospital CIE188	$7,189	6.02	$947	1.09	$9,799	6.68	$10,657	13.28
281	VFD Return Fan <20hp - Hotel CIE193	($245)	0.66	($70)	0.87	($118)	0.80	$311	2.87
282	VFD Return Fan <20hp - Large Office CIE198	$4,917	4.43	$961	1.12	$7,165	5.57	$8,023	12.30
283	VFD Supply Fan <100hp - Hospital CIP132	$37,387	12.45	$5,784	1.12	$50,452	10.33	$52,564	16.95
284	VFD Supply Fan <100hp - Hotel CIP126	($1,691)	0.48	($451)	0.75	($1,312)	0.51	$800	2.39
285	VFD Supply Fan <100hp - Large Office CIP138	$29,684	10.09	$5,903	1.15	$41,597	9.54	$43,709	16.85
286	VFD Tower Fan 20-100hp - Hospital CIP128	$12,755	4.91	$9,977	1.51	$25,967	8.03	$28,204	20.33
287	VFD Tower Fan 20-100hp - Hotel CIP122	$18,620	6.70	$13,857	1.51	$36,682	9.94	$38,919	21.86
288	VFD Tower Fan 20-100hp - Large Office CIP134	($1,762)	0.46	$371	1.21	($552)	0.79	$1,685	4.72
289	VFD Tower Fan <20hp - Hospital CIE189	$2,538	2.77	$2,268	1.47	$5,713	5.06	$6,643	14.95
290	VFD Tower Fan <20hp - Hotel CIE194	$3,946	3.75	$3,200	1.49	$8,284	6.51	$9,214	17.06
291	VFD Tower Fan <20hp - Large Office CIE199	($946)	0.34	($37)	0.93	($652)	0.44	$279	2.19
292	Water Heater Pipe Insulation - 6' CDI139	$286,572	N/A	($43,293)	0.92	$374,055	4.44	$374,055	4.44
293	Water Heater Setback (manual adj) CDI140	$50,942	N/A	($52,784)	0.51	($122)	1.00	($122)	1.00
294	Window Film CIP139	$14	1.21	($9)	0.89	$20	1.35	$47	2.50

2015 ELECTRIC DSM PLAN – CAUSE NO. 44495

Energy efficiency measures considered for the programs were developed using existing Indiana utility program measures (whenever possible) and measures used in other programs in the region. It should be noted that in any plan measures within programs will change and adapt to changing technology and markets. The 2015 Plan shows a framework of measures and programs that can meet the savings goals; however, it is expected that new measures and opportunities will become available during this period and that some measures will phase out as standards change and they are no longer cost effective.

The technologies listed above were developed as a result of the EnerNOC MPS data and other study information in order to guide the plan design. Vectren then hired outside expertise to assist with plan design and development in order to refine the technologies above into a workable plan. Additionally, input into the plan design was obtained from various sources, such as current program managers and implementation partners, in order to establish a solid foundation for the 2015 Plan that is based on actual experience in Vectren's territory. Other program information, such as current evaluations and best practices of other successful DSM programs, was used for adjustments to inputs. Lastly, Vectren received feedback and approval from the Oversight Board before finalizing. The result of these efforts, listed in Table 8-4 below, shows the DSM Programs benefit/cost data per the portfolio of programs filed under Cause No. 44495.

Table 8-4 Program Benefit/Cost Results for 2015 DSM Plan[1]

Commercial	TRC	UCT	RIM	Participant
Small Business Direct Install	2.00	2.21	0.83	3.66
Commercial & Industrial Prescriptive	3.75	5.44	1.02	3.25
Commercial & Industrial New Construction	1.09	2.72	0.87	1.00
Commercial & Industrial Custom	1.64	3.82	0.93	1.52
Commercial Sector Portfolio	**2.17**	**3.08**	**0.90**	**2.63**

Residential	TRC	UCT	RIM	Participant
Residential Lighting	2.18	2.88	0.85	2.94
Home Energy Assessments	1.02	1.02	0.56	NA
Income Qualified Weatherization	1.14	1.14	0.66	NA
Appliance Recycling	2.52	2.51	0.97	5.79
Residential Schools	1.89	1.89	0.72	NA
Efficient Products	1.51	2.02	1.05	1.13
Residential New Construction	1.28	1.52	0.75	1.89
Residential Behavior Savings	1.64	1.64	0.77	NA
Residential Sector Portfolio	**1.49**	**1.64**	**0.77**	**3.36**

Total Portfolio	**1.86**	**2.34**	**0.85**	**2.89**

Table 8-4 Program Benefit/Cost Results for 2015 DSM Plan Cont.[2]

Commercial	Lifetime Cost/ kWh	1st Year Cost/ kWh
Small Business Direct Install	$0.04	$0.32
Commercial & Industrial Prescriptive	$0.01	$0.15
Commercial & Industrial New Construction	$0.03	$0.36
Commercial & Industrial Custom	$0.02	$0.23
Commercial Sector Portfolio	**$0.03**	**$0.26**

[1] Commercial sector includes outreach costs for benefit/cost runs, and residential sector includes outreach and tracking costs for benefit/cost runs

[2] Commercial sector includes outreach costs for benefit/cost runs, and residential sector includes outreach and tracking costs for benefit/cost runs

Residential	Lifetime Cost/kWh	1st Year Cost/kWh
Residential Lighting	$0.03	$0.07
Home Energy Assessments	$0.08	$0.35
Income Qualified Weatherization	$0.07	$0.78
Appliance Recycling	$0.04	$0.16
Residential Schools	$0.04	$0.23
Efficient Products	$0.06	$0.67
Residential New Construction	$0.04	$0.92
Residential Behavior Savings	$0.06	$0.07
Residential Sector Portfolio	**$0.05**	**$0.18**
Total Portfolio	**$0.03**	**$0.21**

Commercial	TRC NPV $	UCT NPV $	Participant NPV $	RIM NPV $
Small Business Direct Install	$2,116,270	$2,319,485	$2,311,703	($888,566)
Commercial & Industrial Prescriptive	$3,072,637	$3,419,025	$2,406,007	$76,945
Commercial & Industrial New Construction	$40,071	$305,069	($32)	($71,053)
Commercial & Industrial Custom	$726,468	$1,376,727	($26,798)	$695,808
Commercial Sector Portfolio	**$5,805,446**	**$7,270,305**	**$5,193,787**	**($1,181,366)**

Residential	TRC NPV $	UCT NPV $	Participant NPV $	RIM NPV $
Residential Lighting	$929,179	$1,121,826	$1,838,832	($307,982)
Home Energy Assessments	$15,690	$15,690	$572,651	($572,019)
Income Qualified Weatherization	$115,688	$115,688	$416,861	($468,781)
Appliance Recycling	$320,800	$319,656	$470,616	($15,444)
Residential Schools	$113,569	$113,569	$182,611	($94,479)
Efficient Products	$352,915	$524,039	$82,526	$53,200
Residential New Construction	$39,816	$61,965	$50,858	($61,654)
Residential Behavior Savings	$274,885	$274,885	$487,718	($212,832)
Residential Sector Portfolio	**$1,992,542**	**$2,377,317**	**$4,102,673**	**($1,849,991)**
Total Portfolio	**$7,797,988**	**$9,647,622**	**$9,296,460**	**($3,031,357)**

The following programs were filed in the 2015 Plan in Cause No. 44495.

School Energy Efficiency Program

Program

The Energy Efficient Schools Program is designed to impact students by teaching them how to conserve energy and to produce cost effective electric savings by influencing students and their families to focus on conservation and the efficient use of electricity.

The program consists of a school education program for 5th grade students attending schools served by Vectren. To help in this effort, each child that participates will receive a take-home energy kit with various energy saving measures for their parents to install in the home. The kits, along with the in-school teaching materials, are designed to make a lasting impression on the students and help them learn ways to conserve energy.

Eligible Customers

The program will be available to selected 5th grade students/schools in the Vectren electric service territory.

Energy/Demand Savings

The proposed savings are attributed to the take-home kits provided to the elementary school children for parents to install. For modeling purposes, the energy savings estimate is 216 kWh per participant and .020 kW.

Table 8-5 School Energy Efficiency Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Residential Schools				
	2015	2,600	560,786	52	$ 128,033
Per Participant Avg Energy Savings (kWh)					216
Per Participant Avg Demand Savings (kW)					0.020
Participant Incremental Cost					$ -
Weighted Avg Measure Life					7
Net To Gross Ratio					96%

Residential Lighting Program

Program

The Residential Lighting Program is a market-based residential DSM program designed to reach residential customers through retail outlets. The program design consists of a buy-down strategy to provide the incentive to consumers to facilitate their purchase of energy-efficient lighting products. This program is justified based on direct energy savings targets, but also has a significant market transformation opportunity.

The program not only empowers customers to take advantage of new lighting technologies and accelerate the adoption of proven energy efficient technologies, but also allows the customers to experience the benefits of energy efficiency and decrease their energy consumption.

Eligible Customers

Any residential customer who receives electric service from Vectren is eligible.

Energy/Demand Savings

The program is designed to provide an incentive for the purchase and installation of CFL bulbs. For modeling purposes, the savings estimates per bulb are 32 kWh annually with demand savings of 0.004 kW.

Table 8-6 Residential Lighting Program Data

Market	Program	Number of Measures	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Residential Lighting				
	2015	261,316	8,334,008	978	$ 596,567
Per Participant Avg Energy Savings (kWh)					32
Per Participant Avg Demand Savings (kW)					0.004
Participant Incremental Cost					$ 3.63
Weighted Avg Measure Life					6
Net To Gross Ratio					49%

Home Energy Assessments

Program

The Home Energy Assessment Program targets a hybrid approach that combines helping customers analyze and understand their energy use via an on-site energy assessment, as well as providing direct installation of energy efficiency measures including efficient low-flow water fixtures and CFL bulbs.

Collaboration and coordination between electric and gas conservation programs will be explored and, to the extent possible, implemented for greatest efficiencies.

Eligible Customers

Any residential customer who receives electric service from Vectren at a single-family residence is eligible, provided the home:

- Was built prior to 1/1/2010;
- Has not had an audit within the last three years; and,
- Is owner occupied or non-owner occupied where occupants have the electric service in their name.

Energy/Demand Savings

For modeling purposes, the energy savings estimate is 1,036 kWh and .164 kW per participant.

Table 8-7 Home Energy Assessments Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Home Energy Assessments				
	2015	2,000	2,072,900	328	$ 716,163
Per Participant Avg Energy Savings (kWh)					1,036
Per Participant Avg Demand Savings (kW)					0.164
Participant Incremental Cost					$ -
Weighted Avg Measure Life					6
Net To Gross Ratio					88%

Income Qualified Weatherization

Program

The Low Income Weatherization program is designed to produce long-term energy and demand savings in the residential market. The program will provide weatherization upgrades to low income homes that otherwise would not have been able to afford the energy saving measures. The program will provide direct installation of energy saving measures, educate consumers on ways to reduce energy consumption, and identify opportunities for additional weatherization measures.

Collaboration and coordination between gas and electric low income programs along with state and federal funding, is recommended to provide the greatest efficiencies among all programs.

Eligible Customers

The Residential Low Income Weatherization Program targets single-family homeowners and tenants, who have electric service in their name with Vectren and with a total household income up to 200% of the federally-established poverty level. Priority will be given to:

a. Single parent households with children under 18 years of age living in dwelling.
b. Households headed by occupants over 65 years of age.
c. Disabled homeowners as defined by the Energy Assistance Program (EAP).
d. Households with high energy intensity usage levels.

Energy/Demand Savings

For modeling purposes, the energy savings estimate is 1,822 kWh per participant annually with demand savings of 0.453 kW.

Table 8-8 Income Qualified Weatherization Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Income Qualified Weatherization				
	2015	564	1,027,651	256	$ 798,474
Per Participant Avg Energy Savings (kWh)					1,822
Per Participant Avg Demand Savings (kW)					0.453
Participant Incremental Cost					$ -
Weighted Avg Measure Life					15
Net To Gross Ratio					100%

Appliance Recycling

Program

The Residential Appliance Recycling program encourages customers to recycle their old inefficient refrigerators and freezers in an environmentally safe manner. The program recycles operable refrigerators or freezers so the appliance no longer uses electricity and is recycled instead of being disposed of in a landfill. An older refrigerator can use as much as twice the amount of energy as new efficient refrigerators. An incentive of $50 will be provided to the customer for each operational unit picked up.

Eligible Customers

Any residential customer with an operable secondary refrigerator or freezer receiving electric service from Vectren is eligible.

Incentive

The program offers customers free pick-up of working refrigerators or freezers and a $50 cash incentive.

Energy/Demand Savings

The program is designed to remove the old, secondary refrigerator or freezer. The savings estimate is 1,230 kWh per measure annually, with a summer demand savings of 0.397 kW.

Table 8-9 Residential Appliance Recycling Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Appliance Recycling				
	2015	1,058	1,301,338	420	$ 212,366
Per Participant Avg Energy Savings (kWh)					1,230
Per Participant Avg Demand Savings (kW)					0.397
Participant Incremental Cost					$ 92.96
Weighted Avg Measure Life					8
Net To Gross Ratio					53%

Residential Efficient Products

Program

To assist customers with the purchase of energy efficient products, prescriptive incentives will be provided on efficient electric measures and equipment (qualifying air conditioning units, heat pumps, thermostats, etc.) above the standard baseline. The program will be promoted through trade allies and appropriate retail outlets.

Eligible Customers

Any residential customer located in the Vectren electric service territory is eligible.

Incentive

Incentives are provided to customers to reduce the difference in first cost between the lower efficient technology and the high efficient option.

Energy/Demand Savings

For modeling purposes, the energy/demand savings estimates are 514 kWh annually per participant (measure) and demand savings of .403 kW.

Table 8-10 Residential Efficient Products Data

Market	Program	Number of Measures	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Efficient Products				
	2015	1,500	771,461	605	$ 516,189
Per Participant Avg Energy Savings (kWh)					514
Per Participant Avg Demand Savings (kW)					0.403
Participant Incremental Cost					$ 421.53
Weighted Avg Measure Life					15
Net To Gross Ratio					73%

Residential Behavioral Savings Program

Program

The Residential Behavioral Savings (RBS) program motivates behavior change and provides relevant, targeted information to the consumer through regularly scheduled direct contact via mailed and emailed home energy reports. The report and web portal include a comparison against a group of similarly sized and equipped homes in the area, usage history comparisons, goal setting tools, and progress trackers. The Home Energy Report program anonymously compares customers' energy use with that of their neighbors of similar home size and demographics. Customers can view the past twelve months of their energy usage and compare and contrast their energy consumption/ costs with others in the same neighborhood. Once a consumer better understands how they use energy, they can then start conserving energy.

Program data and design was provided by OPower, the implementation vendor for the program. OPower provides energy usage insight that drives customers to take action

by selecting the most relevant information for each particular household, which ensures maximum relevancy and high response rate to recommendations.

Eligible Customers

Residential customers who receive electric service from Vectren are eligible.

Energy/Demand Savings

To identify the measurable savings, Vectren proposes to have a set of customers who receive the letter with energy tips and suggestions and a set of control customers who do not receive the letter. The energy consumption of the 2 groups will be compared to determine the measurable savings. For modeling purposes, the annual energy savings was estimated at 126 kWh per participant with demand savings of .041 kW.

Table 8-11 Residential Behavioral Savings Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Behavioral Savings				
	2015	50,400	6,350,400	2,051	$ 432,202
Per Participant Avg Energy Savings (kWh)					126
Per Participant Avg Demand Savings (kW)					0.041
Participant Incremental Cost					$ -
Weighted Avg Measure Life					1
Net To Gross Ratio					100%

Residential New Construction

Program

The Residential New Construction Program will provide incentives and encourage home builders to construct homes that are more efficient than current building codes. The Residential New Construction Program will work closely with builders, educating them on the benefits of energy efficient new homes. Homes may feature additional insulation, better windows, and higher efficiency appliances. The homes should also be

more efficient and comfortable than standard homes constructed to current building codes.

Program incentives are designed to be paid to both all-electric and combination homes that have natural gas heating and water heating. It is important to note that the program is structured such that an incentive will not be paid for an all-electric home that has natural gas available to the home site.

The Residential New Construction Program will address the lost opportunities in this customer segment by promoting energy efficiency at the time the initial decisions are being made. This will ensure efficient results for the life of the home.

Eligible Customers

Any home builder constructing a home to the program specifications in the Vectren electric service territory is eligible.

Incentives

Incentives will be based on a rating tier qualification and are designed to be paid to both all-electric and combination homes that have natural gas space heating.

Energy/ Demand Savings

For modeling purposes, the savings estimates per home are calculated at 1,898 kWh and .309 kW, based upon the blended savings estimate of all participating homes. The specific energy and demand impacts will vary by size and composition of the home and will be characterized through follow-up evaluation and verification procedures.

Table 8-12 Residential New Construction Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Residential New Construction				
	2015	68	129,048	21	$ 119,092
Per Participant Avg Energy Savings (kWh)					1,898
Per Participant Avg Demand Savings (kW)					0.309
Participant Incremental Cost					$ 844.56
Weighted Avg Measure Life					25
Net To Gross Ratio					95%

Commercial and Industrial Prescriptive Program

Program

The Commercial and Industrial (C&I) Prescriptive Program is designed to provide financial incentives on qualifying products to produce greater energy savings in the C&I market. The rebates are designed to promote lower electric energy consumption, assist customers in managing their energy costs and built a sustainable market around energy efficiency. Program participation is achieved by offering incentives structured to cover a portion of the customer's incremental cost of installing prescriptive efficiency measures.

Eligible Customers

Any participating commercial or industrial customer receiving electric service from Vectren is eligible.

Incentive

Incentives are provided to customers to reduce the difference in first cost between the lower efficient technology and the high efficient option.

Energy/Demand Savings

For modeling purposes, the energy savings estimate is 487 kWh per participant (measure) and demand savings of .089 kW.

Table 8-13 Commercial and Industrial Prescriptive Program Data

Market	Program	Number of Measures	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Commercial & Industrial	Commercial & Industrial Prescriptive				
	2015	10,470	5,103,942	935	$ 769,573
Per Participant Avg Energy Savings (kWh)					487
Per Participant Avg Demand Savings (kW)					0.089
Participant Incremental Cost					$ 102.29
Weighted Avg Measure Life					14
Net To Gross Ratio					80%

Commercial and Industrial Audit and Custom Efficiency Program

Program

The Commercial and Industrial Custom Program promote the implementation of customized energy saving measures at qualifying customer facilities. Incentives promoted through this program serve to reduce the cost of implementing energy reducing projects and upgrading to high-efficiency equipment. Due to the nature of a custom energy efficiency program, a wide variety of projects are eligible.

The technical audit or compressed air system study offers an assessment to systematically identify energy saving opportunities for customers and provides a mechanism to prioritize and phase-in projects that best meet customer needs. In turn, the opportunities identified from the audit can be turned in for the customized efficiency program. These two components work hand in hand to deliver energy savings to Vectren commercial and industrial customers.

Eligible Customers

Any participating commercial or industrial customer receiving electric service from Vectren is eligible.

Incentive

Vectren will provide a customer incentive based on the estimated kWh savings at a modeled rate of .12 cents per kWh, and is paid based on the first year annual savings reduction.

Energy/Demand Savings

The custom nature of the program makes it difficult to develop a prototypical example. Each building will have very site specific projects and impacts. For modeling purposes the energy/demand savings estimates are 95,248 kWh per participant (measure) and demand savings of 15.455 kW.

Table 8-14 Commercial and Industrial Audit & Custom Efficiency Program Data

Market	Program	Number of Projects	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Commercial & Industrial	Commercial & Industrial Custom				
	2015	22	2,095,450	340	$ 488,274
Per Participant Avg Energy Savings (kWh)					95,248
Per Participant Avg Demand Savings (kW)					15.455
Participant Incremental Cost					$ 41,400.96
Weighted Avg Measure Life					12
Net To Gross Ratio					99%

Commercial and Industrial New Construction Program

Program

The Commercial and Industrial New Construction Program provides value by promoting energy efficient designs with the goal of developing projects that are more energy efficient than current Indiana building code. Incentives promoted through this program serve to reduce the incremental cost to upgrade to high-efficiency equipment over standard efficiency options for Vectren customers. The program includes equipment with easily calculated savings and provides straightforward and easy participation for customers.

Eligible Customers

Any participating commercial or industrial customer receiving electric service from Vectren is eligible.

Incentive

The program is designed to pay .12 cents per kWh saved up to $100,000 based on the first year energy savings determined in the final energy model.

Energy/Demand Savings

For modeling purposes the estimated energy/demand savings per participant are 35,100 kWh and 6.286 kW.

Table 8-15 Commercial and Industrial New Construction Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Commercial & Industrial	Commercial & Industrial New Construction				
	2015	14	491,400	88	$ 177,373
Per Participant Avg Energy Savings (kWh)					35,100
Per Participant Avg Demand Savings (kW)					6.286
Participant Incremental Cost					$ 24,517.34
Weighted Avg Measure Life					14
Net To Gross Ratio					95%

Small Business Direct Install

Program

The program provides value by directly installing energy efficient products such as high efficiency lighting, low flow water saving measures and vending machine controls. The program helps businesses identify and install cost effective energy saving measures by providing an on-site energy assessment customized for their business.

Eligible Customers

Any participating Vectren small business customer with a maximum peak energy demand of less than 300 kW is eligible.

Incentive

In addition to the low cost measures installed during the audit, the program will also pay a cash incentive of up to 75% of the cost of any recommended improvements identified through the audit.

Energy/Demand Savings

For modeling purposes the estimated energy/demand savings per participant are 6,001 kWh and 1.622 kW.

Table 8-16 Small Business Direct Install Program Data

Market	Program	Number of Projects	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Commercial	Small Business Direct Install				
	2015	1,000	6,001,171	1,622	$ 1,909,188
Per Participant Avg Energy Savings (kWh)					6,001
Per Participant Avg Demand Savings (kW)					1.622
Participant Incremental Cost					$ 868.98
Weighted Avg Measure Life					10
Net To Gross Ratio					100%

DSM Portfolio Objective and Impacts

Vectren plans to reduce residential and commercial/industrial customer usage by 34,240 MWh in 2015. Vectren also projects to achieve a reduction in summer peak demand of 7.69 MW in 2015. In implementing these programs, consideration will be given to utilizing small businesses when feasible. Table 8-17 outlines the portfolio and the associated programs, as well as the projected energy/demand impacts, program costs, and customer participation of DSM programs offered under Cause No. 44495.

Table 8-17 Projected Energy and Peak Savings – Cause No. 44495

COMMERCIAL	2015 kWh Total	2015 kW
Small Business Direct Install	6,001,171	1,622
Commercial & Industrial Prescriptive	5,103,942	935
Commercial & Industrial New Construction	491,400	88
Commercial & Industrial Custom	2,095,450	340
Commercial Total	**13,691,963**	**2,985**

RESIDENTIAL	2015 kWh Total	2015 kW
Residential Lighting	8,334,008	978
Home Energy Assessments	2,072,900	328
Income Qualified Weatherization	1,027,651	256
Appliance Recycling	1,301,338	420
Residential Schools	560,786	52
Efficient Products	771,461	605
Residential New Construction	129,048	21
Behavior Savings	6,350,400	2,051
Residential Total	**20,547,593**	**4,711**

While Vectren believes this level of savings is achievable, it will require robust programs for all classes of retail customers.

Given the market assessment, collaborative process, portfolio cost/benefit modeling efforts, and DSM program portfolio proposal, Vectren used the projected demand-side reductions from the programs as an input into the IRP process, rather than allowing the integration modeling to independently select some level of DSM to meet customer requirements. With respect to DSM, the programs that pass cost effectiveness testing are input into the integration analysis as a resource. IRP DSM modeling is discussed later in this chapter.

Customer Outreach and Education

Program

This program will raise awareness and drive customer participation as well as educate customers on how to manage their energy bills. The program will include the following goals as objectives:

- Build awareness;
- Educate consumers on how to conserve energy and reduce demand;
- Educate customers on how to manage their energy costs and reduce their bill;
- Communicate Vectren's support of customer energy efficiency needs; and
- Drive participation in the DSM programs.

This annual program will include paid media, web-based tools to analyze bills, energy audit tools, and energy efficiency and DSM program education and information. Informational guides and sales promotion materials for specific programs will also be included.

Vectren will oversee the outreach and education programs for the DSM programs. Vectren will utilize the services of communication and energy efficiency experts to deliver the demand and energy efficiency message.

Eligible Customers

Any Vectren electric customer will be eligible.

Energy/Demand Savings

This communications effort differs from typical DSM programs in that there are no direct estimates of participants, savings, costs, and cost-effectiveness tests. Such estimates are considered impractical for these types of overarching efforts to educate consumers and drive participation in other DSM programs. The California Standard Practice Manual (p. 5) addresses this issue as follows:

"For generalized information programs (e.g., when customers are provided generic information on means of reducing utility bills without the benefit of on-site evaluations or customer billing data), cost-effectiveness tests are not expected because of the extreme difficulty in establishing meaningful estimates of load impacts."

This effort is the key to achieving greater energy savings by convincing the families and businesses making housing/facility, appliance and equipment investments to opt for greater energy efficiency. The first step in convincing the public and businesses to invest in energy efficiency is to raise their awareness. It is essential that a broad public education and outreach campaign not only raise awareness of what consumers can do to save energy and control their energy bills, but to prime them for participation in the various DSM programs. The budget is $150,000 each for Residential and Commercial programs, for a total of $300,000.

Table 8-18 DSM Outreach & Education Program Budget

Customer Outreach	Residential	Business	Total Program Costs
Outreach	$150,000	$150,000	$300,000

IRP DSM MODELING

Vectren continues to support DSM related energy efficiency efforts as a fundamental part of the services that are provided to customers in order to help them manage their energy bills. The Market Potential study, developed by EnerNoc on behalf of the Vectren Oversight Board, illustrated a level of ongoing DSM energy efficiency is cost effective and Vectren believes the inclusion of the described level of ongoing DSM energy efficiency is best reflected in the base case sales forecast. DSM energy efficiency programs included in the base sales forecast are available to all customer classes at a targeted level of 1% eligible annual savings for 2015 – 2019 and 0.5%

annually thereafter for customer load that has not opted-out of DSM programs. Vectren believes that a cost effective level of DSM energy efficiency may be supported by policy considerations beyond capacity planning which are not always captured in the IRP modeling process.

Vectren did model the option of offering DSM energy efficiency programs designed to achieve more than the level reflected in the base case sales forecast to determine if it is selected as a resource to meet future electric requirements. Vectren's approach attempts to balance its commitment to a level of cost-effective DSM, while evaluating additional DSM resources consistent with least cost planning. Below is a list of major assumptions included in Vectren's IRP DSM modeling.

Vectren began by creating savings blocks based on 0.5% of eligible sales based on a projection that 80% of large customers will opt out of Vectren sponsored DSM programs. The maximum amount of possible additional DSM that could be selected was 2% (embedded savings + additional modeled blocks) in 2018-2019. Beyond 2019, the model was limited to selecting 1.5% (embedded + additional modeled blocks) of total eligible sales, consistent with the proposed Clean Power Plan (111d). Levelized costs were based on the Market Potential study and Vectren's 2015 Plan. Consistent with the Market Potential study, each block cost more than the last and increased over time. Levelized costs of energy saved began at approximately 3 cents per kWh for the first available block in 2015 and increased to approximately 6.4 cents for the last available block in 2034. In order to minimize ramping costs, DSM programs were required to run for at least 3 consecutive years.

Based on these assumptions, DSM successfully competed with resource alternatives within the planning model to help meet future load requirements. DSM was selected in several resource plans as discussed further in Chapter 10 Generation Planning.

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CHAPTER 9

TRANSMISSION AND DISTRIBUTION PLANNING

INTRODUCTION

In accordance with IURC Rule 170 IAC, Vectren analyzed its transmission and distribution system's ability to meet future electric service requirements reliably and economically through the year 2034. This chapter describes the criteria applied in the analysis and the system conditions studied. The study was conducted to maintain compliance with the requirements of the Midcontinent Independent System Operator (MISO), the *Reliability* First (RF) in conjunction with NERC requirements, as well as Vectren's internal planning criteria. Internal Long Range Plans are completed annually. In addition, Vectren has worked closely with MISO Transmission Expansion Plans (MTEP) and RF in performing regional studies, which include proposed projects identified in Vectren studies.

Modeling of the transmission system was conducted with steady-state conditions using the Power Technologies Inc.'s Power System Simulator Program for Engineers (PTI-PSS/E). The models and the studies and assessment on these models comply with all NERC, RF, MISO and IURC requirements, and they include real and reactive flows, voltages, generation dispatch, load, and facilities appropriate for the time period studied. The primary criteria for assessing the adequacy of the internal Vectren transmission system were (1) single contingency outages of transmission lines and transformers during peak conditions, and (2) selected double and multiple contingencies. Interconnections were also assessed by examining single, double, and other multiple contingencies.

In addition, short circuit models were developed and analyzed through the use of Advanced Systems for Power Engineering, Inc.'s short circuit program (ASPEN-OneLiner).

Dynamic simulation was also performed using PTI-PSS/E to examine the performance of the interconnected transmission system to various electrical faults. The Vectren system remains stable for a variety of faulted conditions.

METHODOLOGY

The distribution system review covers native load as described in previous chapters in this IRP. The Transmission system review also covers loads connected to Vectren's transmission system such as municipals and Independent Power Producers (IPP's) that Vectren is not obligated to serve or include in its generation resources. The primary reason is to determine impacts or limitations in the transmission capacity to serve the Vectren native load. Vectren adheres to the transmission planning criteria developed and published by MISO in its document MISO *Transmission Expansion Planning*; (MTEP) and by RF through NERC in its *Reliability Standards* under *Transmission Planning (TPL-001 through TPL-004)*.

The basis for the selection of RF reliability criteria offers five points for member recognition.

1. The need to plan bulk electric systems that will withstand adverse credible disturbances without experiencing uncontrolled interruptions.

2. The importance of providing a high degree of reliability for local power supply but the impossibility of providing 100 percent reliability to every customer or every local area.

3. The importance of considering local conditions and requirements in establishing transmission reliability criteria for the local area power supply and the need, therefore, to view reliability in local areas primarily as the responsibility of the individual RFC members. However, local area

disturbances must not jeopardize the overall integrity of the Bulk Electric System.

4. The importance of mitigating the frequency, duration and extent of major Bulk Electric System outages.

5. The importance of mitigating the effect of conditions that might result from events such as national emergencies, strikes, or major outages on other regional networks.

SYSTEM INTEGRITY ANALYSIS – 2013 (SEASONAL ANNUAL, INCLUDES SPRING, SUMMER, FALL, AND WINTER)

Based on initial conditions for load, generation, and system topology the following tests were conducted.

1. Single contingency:
   - Outage of any line
   - Outage of any transformer
   - Outage of any generator
2. Multiple contingencies:
   - Double outage of any combination of generators, lines and transformers
   - Double outages of generators
   - Sensitivity outages: two lines or transformers under different Generation dispatch scenarios
3. Extreme Contingencies:
   - Loss of all generation at a plant site
   - Loss of entire switchyard with associated load, generation and line connectivity where three or more 100kV or higher voltage lines are connected

As a result of these tests, various system operational or construction improvements have been postulated. These improvements may be either operator action, (such as shifting generation or switching lines), or the installation of actual substations, the construction of transmission lines, or the upgrading of facilities. Required construction improvements have been prioritized by where they fall in the contingency spectrum. Improvements that must be made in response to a single line outage have higher priority than improvements resulting from a more unlikely occurrence.

SYSTEM INTEGRITY ANALYSIS – 2018 (NEAR TERM – WITHIN 1-5 YEARS)

Using updated load and generation forecasts and included planned upgrades, the same analysis is performed for the 2013 system. Contingency analysis is also the same as for the 2013 system.

SYSTEM INTEGRITY ANALYSIS – 2022 (LONG TERM – 6-10 YEARS)

Using updated load and generation forecasts and included planned upgrades, the same analysis is performed for the 2013 system. Contingency analysis is the same as for the 2013 system.

TRANSMISSION ADEQUACY SUMMARY TABLE

Table 9-1 shows the Vectren generation and load resources, as summarized from previous chapters, as well as the generation and load resources expected to be served from the transmission system for the entire Vectren Local Balancing Authority (LBA) as coordinated by MISO.

Table 9-1 Transmission Import Adequacy/Shortfall Assessment

Year	Vectren Available Gen (MW)[1]	IPP's & other Gen (MW)	Vectren Firm Peak Demand (MW)[2]	Muni's & Other Load (MW)	Proj. Inter-Change (MW)	Trans. System Import Cap (MW)
2014	1,155	596	1,145	690	-84	728
2015	1,155	680	1,155	690	-10	802
2016	1,155	680	1,156	690	-11	801
2017	1,155	680	1,113	690	32	844
2018	1,155	680	1,109	690	36	848
2019	1,155	680	1,106	690	39	851
2020	1,155	680	1,106	690	39	851
2021	1,155	680	1,106	690	39	851
2022	1,155	680	1,107	690	38	850
2023	1,155	680	1,107	690	38	850
2024	1,155	680	1,107	690	38	850
2025	1,155	680	1,106	690	39	851
2026	1,155	680	1,106	690	39	851
2027	1,155	680	1,107	690	38	850
2028	1,155	680	1,109	690	36	848
2029	1,155	680	1,110	690	35	847
2030	1,155	680	1,111	690	34	846
2031	1,155	680	1,111	690	34	846
2032	1,155	680	1,113	690	32	844
2033	1,155	680	1,114	690	31	843
2034	1,155	680	1,115	690	30	842

The table reflects that if all available internal generation is on line the expected net interchange would be negative for years 2014 through 2016 and positive or exporting for all years beyond 2017. This reliability measure indicates that additional import transmission capacity is not needed for our generation to serve our load. However, the table does not reflect several other factors such as potential purchases and sales. The

[1] Values from Table 10-1 Characteristics of Existing Generation Resources
[2] Values from Table 5-4 Base Case Demand Forecast

table reflects total generation capability and not a reasonable economic dispatch under all conditions. It is likely that renewable energy resources may be imported using the transmission system in lieu of running local generation. It is assumed that the gas peaking turbines would likely not be dispatched during some near peak summer conditions, in which it is not only possible, but likely that the expected interchange could be importing 300-400 MW. These values are also supported by actual historical interchange. In any event, MISO will dispatch the available resources to serve the load based on N-1 contingency analysis and economics and losses. With the largest generation resource on the Vectren system at 300 MW, the transmission system capacity is adequate under reasonable expected resource dispatches and contingencies and additional growth. Within each PSS/E case, the actual load, generation dispatch, firm purchases and sales, and expected interchange is appropriate for the time period.

RECOMMENDATIONS: 2014 - 2034

No transmission facilities were identified specifically due to proposed generation interconnections, transmission service requests or energy resources in this IRP process. Since the projected load growth is essentially flat and no new generation resources or retirements are planned, no new transmission facilities have been identified. In addition, significant upgrades were constructed in 2012 as a result of the MISO Regional Expansion Criteria and Benefits (RECB) process. The completed projects include the construction of a new 345 kV line from the Duke Gibson Station to the Vectren AB Brown Station to the BREC Reid Station. The Duke Gibson to Vectren AB Brown to BREC Reid EHV Substation is complete and energized. This project also included the construction of a 345/138 kV substation at Vectren's AB Brown Station which is also complete. A new 138kV line (Z77) from FB Culley Substation to Oak Grove Substation to Northeast Substation is complete. This facility allows for better generation dispatch diversity with lower congestion costs under contingencies. However, recent generation and load changes in the Commonwealth of Kentucky are

expected to impact the Vectren system due to flow through congestion. MISO is considering Market Congestion Projects for mitigation of the projected congestion costs, and a project will only move forward if the benefits exceed the costs metric. Multiple distribution substation upgrades were completed to include Bergdolt and Libbert Substations. Leonard Rd 69kV Switching substation should be complete in 2014 and will support a greater number of contingencies for substransmission on Evansville's west side. Demand side management and energy conservation is expected to provide some load reduction on the Vectren system.

Local load growth areas have been identified for potential new business loads. Near term projections indicate the need for at least 2 more distribution substations tentatively identified as Roesner Road and Princeton South areas, as well as potentially a new plant.

The specific projects to be completed in the future years will depend on the load growth, the location of generation facilities, and/or on the source of purchased power. General recommendations are as follows:

1. A number of 69 kV transmission upgrades will be needed. An engineering evaluation will be conducted for upgrading the identified lines to higher operating temperature and for reconductoring some lines.
2. A number of substations will need to be modified.
3. Several new 138 and 69 kV lines and substations are planned to be added in this timeframe.
4. New high voltage interconnections with neighboring utilities are being investigated, including 345 kV facilities, to improve import capability and improve regional reliability.
5. If new generation capacity is added within the Vectren system, transmission facilities would also be planned to incorporate the new power source.

6. If new generation capacity were acquired outside the Vectren system, additional new interconnections may be needed. These projects would be investigated and would require involvement of other utilities.

All of these potential transmission projects would be planned with and coordinated through the MISO.

COST PROJECTIONS:

Vectren is projecting its annual transmission, substation, and distribution expenditures to remain flat to slightly decrease over the next five years. The primary factors are that there is not a recommendation to add new generation sources in this IRP that causes new construction and the existing transmission system is adequate for full deliverability of the existing generation sources. A reason for part of the decrease is the 345kV project was completed in 2012 and spending in following years are expected to be lower. However, the Federal Stimulus Plan funding is expected to force some transmission and distribution relocations increasing in some areas due to roadway improvements. Approximately half of these are expected to be reimbursable with the remaining cost incurred by Vectren. Also, increasing demands for Smart Grid technology and infrastructure are resulting in some additional expenditure. New business and load growth forecast is expected to stay relatively flat. The need for import capability due to generation additions and retirements are expected to remain mostly unchanged as well. Tables 9-2 and 9-3 reflect both previous annual costs and projected annual spend:

Table 9-2 Actual Expenditures

	Dist. Feeder	Dist. Substation	Trans. Lines	Trans. Substation
2009	$27.3M	$5.2M	$27.2M	$20.2M
2010	$15.4M	$5.2M	$40.6M	$10.5M
2011	$26.6M	$6.5M	$24.8M	$1.4M
2012	$19.2M	$4.6M	$33.5M	$4.7M
2013	$23.8M	$2.8M	$14.9M	$4.8M

Table 9-3 Planned Expenditures

	Dist. Lines	Dist. Substation	Trans. Lines	Trans. Substation
2014	$28.9M	$4.3M	$8.5M	$4.5M
2015	$27.0M	$5.8M	$7.4M	$4.8M
2016	$27.0M	$7.9M	$5.2M	$4.8M
2017	$27.5M	$6.7M	$8.8M	$2.3M
2018	$27.6M	$4.5M	$8.6M	$4.3M

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CHAPTER 10

GENERATION PLANNING

INTRODUCTION

The purpose of the generation plan is to develop the optimal strategy for adding the resources as necessary to reliably meet the future demand requirements of Vectren's electric customers. The plan is integrated in that both supply-side and demand-side alternatives were considered and evaluated. The optimal plan is defined as the best possible combination of resource additions that result in reliable service at the lowest cost to customers over the twenty year planning horizon. The optimal resource plan is determined by evaluating all of the possible resource combinations and choosing the plan that minimizes the Net Present Value (NPV).

APPROACH

The process of determining the best resource plan was approached as an optimization problem. Vectren's consultant, Burns and McDonnell, utilized the Strategist software tool developed and supported by Ventyx of Atlanta, GA. Strategist is a strategic planning system that integrates financial, resource, marketing, and customer information. Strategist allows for addressing all aspects of integrated planning at the level of detail required for informed decision making. Strategist handles production costing, capital expenditure and recovery, financial and tax implications, and optimization all within one software system.

An optimization method has three elements: an objective, constraints, and alternatives. For the electric integration process, the three elements can be summarized as follows:

Objective

The objective of the integration analysis was to determine the optimal resource plan by minimizing the NPV. For the purposes of this discussion, the planning period NPV is defined as the net present value of operating costs including fuel plus capital costs. Power purchases and sales are also included in the NPV analysis for the 20 year period, 2015 – 2034. NPV numbers were developed by integrating three scenarios with four different energy forecasts. The generation options within the scenarios, along with

the alternative generation (discussed in Chapter 6 Electric Supply Analysis and Chapter 7 Renewables and Clean Energy), additional DSM (discussed in Chapter 8 DSM Resources) and purchasing capacity from the market were compared against the capacity needs of the four energy forecasts yielding twelve plans of the least cost NPV. These twelve plans were then vetted against multiple sensitivities to see which plan would be the most versatile given a wide range of possible outcomes.

Constraints

The primary constraint was to maintain a minimum planning reserve margin (PRM). MISO has moved to an unforced capacity (UCAP) PRM in the last couple of years. The UCAP accounts for the amount of installed capacity (ICAP) or nameplate capacity available at system's mega-watt peak hour of the peak day after discounting for the time that the generating facility is not available due to historical outages such as maintenance and repairs. The UCAP PRM is subject to change each year depending on MISO's projected need. For the year 2014, MISO set forth a UCAP PRM of 7.3%. This means that Vectren must maintain at least 7.3% over the peak demand of its customers on a UCAP basis. The goal is to determine the minimum planning reserve margin that would result in the MISO system experiencing less than one loss of load event every ten years. Other constraints include the project development and build times for new construction alternatives, transmission import constraints, reliability considerations, and the characteristics of existing resources and demand.

Alternatives

A broad array of alternative generation and DSM was included in the optimization analysis. The full range of supply-side resource alternatives were identified and discussed in Chapter 6 Electric Supply Analysis. Likewise, the demand-side alternatives were covered in Chapter 8 DSM Resources.

DISCUSSION OF KEY INPUTS AND ASSUMPTIONS

The NPVs were determined by evaluating all of the pertinent costs that could impact future resource additions. The NPVs include the operating and maintenance (O&M) costs of existing and new facilities and the financial costs associated with capital investments. O&M costs include both fixed and variable expenses such as fuel, production labor, maintenance expenses, and chemical costs for environmental controls.

Please note that this analysis does not explicitly include all of Vectren's Power Supply and Energy Delivery costs related to serving retail electric customers. Costs that would be common to all of the potential resource plans (e.g., allocated admin and general costs, transmission and distribution costs, other embedded costs, etc.) were not included because they had no impact on the comparative economic analysis. The considered costs were primarily related to O&M and new capital associated with power generation activities. Therefore, comparisons between the base case and alternate scenarios should be viewed within this context.

Electric Demand Forecast

As mentioned in the prior section, the electric peak and energy forecast is discussed in detail in Chapter 5 Sales & Demand Forecast. The four demand forecast results used in the optimization analysis are summarized in Table 5-3. The four forecasts consist of a base, a low, and two separate high demand forecasts.

Characteristics of Existing Generating Resources

The operating characteristics of existing Vectren owned electric generating resources, as they were simulated for the purposes of the integration analysis are summarized in Table 10-1. These characteristics were applied to all years of the study period.

Table 10-1 Characteristics of Existing Generating Resources

Resource Name	UCAP (MW)	Primary Fuel	Resource type	EFOR (%)	Estimated Full Load Heat Rate (Btu/kwhn)
AB Brown 1	228	coal	steam	4.9	10,800
AB Brown 2	233	coal	steam	3.6	10,700
FB Culley 2	83	coal	steam	7.4	11,700
FB Culley 3	257	coal	steam	4.3	10,400
Warrick 4	135	coal	steam	10.2	10,200
AB Brown 3	73	gas	combustion turbine	0.0	12,000
AB Brown 4	69	gas	combustion turbine	3.6	11,700
BAGS 2	59	gas	combustion turbine	3.6	13,000
Northeast 1	9	gas	combustion turbine	2.7	15,000
Northeast 2	9	gas	combustion turbine	2.7	15,000
Blackfoot[1]	3	landfill gas	IC engine	5.0	9,000

Existing Purchased Power

Vectren has an existing and ongoing firm purchased capacity and energy commitment with the Ohio Valley Electric Corporation (OVEC). The UCAP of this commitment equals 30 MW. It was also assumed that this resource would be present throughout the 20-year study period.

Finally, as discussed in Chapter 7 Renewables and Clean Energy, Vectren has two long-term purchase power agreements for wind energy. These purchases were assumed to be in place for the entire IRP study period. The UCAP for Vectren's wind capacity is approximately 9.1% or 7.3 MW of the 80 MW of wind.

[1] Blackfoot is "behind the meter" and is accounted for as a credit to load

Fuel Prices

The cost of fuel is one of the largest cost components of the analysis. Therefore, the assumptions that are made regarding future fuel prices are a very important variable for developing a least cost resource plan.

Vectren utilized data from three sources to develop the fuel price forecasts for this IRP. The natural gas price forecast is an average of U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2014 Reference case[1], Wood Mackenzie long term forecast[2], and Black & Veatch's natural gas forecast[3]. Basis assumptions were applied to simulate the delivered burner tip gas cost to Vectren generators. To develop the coal price forecast; Vectren utilized the same three sources and averaged their coal forecasts together to develop the IRP forecast.

An important factor to consider when developing or analyzing long-term fuel price forecasts is the impact that the Clean Power Plan (discussed in Chapter 4 Environmental) may have on the forecasts. Another factor to consider is the uncertainty of markets in the future. The further out the forecast goes the more uncertain the projection becomes. Market conditions and customer demand are continually evaluated when procuring fuel for use in Vectren's electric generation units. Vectren maintains an adequate supply of coal in physical inventory on the ground at each of plant location to ensure reliable service to customers as a prudent contingency in the event of unforeseen supply interruptions due to weather, labor, etc. Table 10-2 shows the average annual delivered base case fuel price forecasts for coal and natural gas.

[1] Included in the Technical Appendix, section E
[2] Wood Mackenzie long term forecasts are subscription based and proprietary.
[3] Black and Veatch's long term forecasts are subscription based and proprietary.

Table 10-2 Base Fuel Price Projection

IRP Base Case Delivered Forecasts		
	Real 2014$/MMBtu	
Year	Coal	Natural Gas
2015	2.57	4.65
2016	2.54	4.86
2017	2.54	5.03
2018	2.59	5.31
2019	2.62	5.46
2020	2.60	5.66
2021	2.61	5.71
2022	2.64	5.72
2023	2.63	5.82
2024	2.67	6.06
2025	2.65	6.15
2026	2.65	6.28
2027	2.67	6.33
2028	2.68	6.43
2029	2.71	6.59
2030	2.71	6.72
2031	2.71	6.82
2032	2.74	6.99
2033	2.80	7.16
2034	2.81	7.35

Environmental Considerations

Chapter 4 Environmental discusses environmental issues in detail. Variable cost impacts associated with running FGD, SCR and other environmental equipment were included in the revenue requirement calculations as part of the integration analysis.

Financial Assumptions

The financial assumptions with respect to capital investments required to add new construction resource alternatives are summarized in Chapter 6 Electric Supply Analysis. Additional information can be found in the Technology Assessment in the Technical Appendix, section B. Additional information regarding the projected costs energy efficiency programs can be found in Chapter 8 DSM Resources. The declining

costs of utility scale solar (50 MW blocks) were modeled as an asymptotic curve beginning at $1,880 per KWac in 2014 and declining to $1,500 per KWac in 2020 and staying flat in real terms for the remainder of the planning horizon.

General Inflation Forecast

The general inflation forecast used in the assumptions is 1.6%. This inflation rate comes from the Federal Reserve Bank of St. Louis. This is also very close to the compound annual growth rate used in the EIA AEO 2014 for the years that are covered in the IRP.

Additional Considerations

The energy industry landscape has been changing at a fast pace, affecting both electric utilities and their customers. Although there is little clarity on how the state of Indiana will choose to implement the EPA's Clean Power Plan, it could drive substantial changes to the mix of resources available to meet customer electric demand. The EPA's MATS rule has resulted in numerous announcements of coal plant retirements across the US. As a result, MISO is predicting potential capacity shortfalls in the next few years. With low natural gas prices, some large industrial customers are considering generating their own electricity, which could affect future energy forecasts. Additionally, the proportion of residential and commercial customers installing solar panels to generate electricity continues to rise, which will effectively lower future demand for energy from the system.

Vectren has taken all of these factors into consideration in the 2014 IRP by either modeling assumed inputs, as is the case with customer-owned solar panels, or outside of modeling in the risk analysis. The combination of these factors makes the future very uncertain. Vectren continues to evaluate these developments and plan for the future with an emphasis on keeping costs as low and fair as possible for all customers, while maintaining reliability and meeting regulations.

INTEGRATION ANALYSIS RESULTS

Base Demand Forecast (Growth Scenario 1)

Plans A-1 B-1 and C-1 represent the base demand forecast in combination with the three basic portfolio themes of "A"- Base (serve customers with existing resources & DSM), "B" – FB Culley 2 Unit Retirement Scenario and "C" – Renewable Portfolio Standard. It should be noted that no new capacity is required under this load forecast. Therefore, the resource additions in plan C-1 are driven by the renewable energy constraints unique to the renewable portfolio scenario.

This case represents the base set of assumptions and inputs as presented in the preceding sections of this chapter. For this analysis, no additional constraints were introduced that would prevent the planning model from selecting the set of future supply-side or demand side resources that resulted in the lowest NPV.

Table 10-3 shows the resource plan for the base demand forecast and the associated NPV's. Plans A-1 and B-1 are essentially the same with only about 0.5 % difference in the NPV's. Plan C-1 which is 2.4% higher reflects the capital expense of additional renewable resources. All three plans are the same through 2019 where a DSM block is selected in the more expensive plan C-1. This will be re-evaluated in future IRP cycles as various uncertainty factors are resolved over time.

Table 10-3 Base Demand Forecast (Growth Scenario 1)

Energy Sales Case :	Base Demand Forecast		
Scenario :	Base	FB Culley 2 Unit Retirement	RPS[1]
Plan ID :	Plan A1	Plan B1	Plan C1
2015			
2016			
2017			
2018			
2019			0.5% DSM[2] Block (2019-2034)
2020		Shutdown FB Culley 2	0.5% DSM Block (2020-2034)
2021			
2022			
2023			
2024			Solar PV (1x50 MW)
2025			Solar PV[3] (4x50 MW)
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
NPV[4]	$4,874,614	$4,848,213	$4,991,616
% Difference	0.0%	-0.5%	2.4%

[1] RPS = Renewable Portfolio Standard
[2] DSM = Demand Side Management
[3] PV = Photovoltaic
[4] Net Present Value inclusive of wholesale adjustment (2014 $)

Low Demand Forecast (Growth Scenario 2)

Plans A-2, B-2 and C-2 represent the low demand forecast in combination with the three basic portfolio themes of "A"- Base (serve customers with existing resources & DSM), "B" – FB Culley 2 Unit Retirement Scenario and "C" – Renewable Portfolio Standard. It should be noted that no new capacity is required under this load forecast. Therefore, the resource additions in plan C-2 are driven by the renewable energy constraints unique to the renewable portfolio scenario.

This case represents the base set of assumptions and inputs as presented in the preceding sections of this chapter. For this analysis, no additional constraints were introduced that would prevent the planning model from selecting the set of future supply-side or additional demand side resources that resulted in the lowest NPV.

Table 10-4 shows the resource plan for the base demand forecast and the associated NPV's. Plans A-2 and B-2 are essentially the same with only about 0.7 % difference in the NPV's. Plan C-2 which is 2.1% higher reflects the capital expense of additional renewable resources. All three plans are the same through 2017 where a DSM block is selected in the more expensive plan C-2.

Table 10-4 Low Demand Forecast (Growth Scenario 2)

Energy Sales Case :	Low Demand Forecast		
Scenario :	Base	FB Culley 2 Unit Retirement	RPS[1]
Plan ID :	Plan A2	Plan B2	Plan C2
2015			
2016			
2017			0.5% DSM[2] Block (2017-2034)
2018			
2019			
2020		Shutdown FB Culley 2	0.5% DSM Block (2020-2034)
2021			
2022			
2023			
2024			
2025			Solar PV[3] (4x50 MW)
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
NPV[4]	$4,771,789	$4,739,585	$4,871,859
% Difference	0.0%	-0.7%	2.1%

[1] RPS = Renewable Portfolio Standard
[2] DSM = Demand Side Management
[3] PV = Photovoltaic
[4] Net Present Value inclusive of wholesale adjustment (2014 $)

High (modeled) Demand Forecast (Growth Scenario 3)

Plans A-3, B-3 and C-3 represent the High (modeled) demand forecast in combination with the three basic portfolio themes of "A"- Base (serve customers with existing resources & DSM), "B" – FB Culley 2 Unit Retirement Scenario and "C" – Renewable Portfolio Standard. It should be noted that no new capacity is required under this load forecast as can be seen in case A-3. However, the assumed retirement of Culley unit 2 in 2020 in conjunction with the increase in load drives some capacity additions in case B-3. The resource additions in plan C-3 are driven by the renewable energy constraints unique to the renewable portfolio scenario. However, the timing of the resources is slightly different due to interim renewable constraint in the renewable portfolio scenario.

This case represents the base set of assumptions and inputs as presented in the preceding sections of this chapter. For this analysis, no additional constraints were introduced that would prevent the planning model from selecting the set of future supply-side or additional demand side resources that resulted in the lowest NPV.

Table 10-5 shows the resource plan for the high (modeled) demand forecast and the associated NPV's. Plans A-3 and B-3 are essentially the same with only about 0.3% difference in the NPV's. Plan C-3 which is 2.1% higher reflects the capital expense of additional renewable resources. The higher load growth in combination with the assumed retirement of Culley 2 suggests that more energy efficiency measures should be implemented soon if that combination of were to occur. However, a mere 0.2% difference in the NPV's between plan A-3 and B-3 is not enough to drive such a major change.

Table 10-5 High (modeled) Demand Forecast (Growth Scenario 3)

Energy Sales Case :	High (modeled) Demand Forecast		
Scenario :	Base	FB Culley 2 Unit Retirement	RPS[1]
Plan ID :	Plan A3	Plan B3	Plan C3
2015		0.5% DSM[2] Block (2015-2034)	
2016			
2017			
2018			
2019			
2020		0.5% DSM Block ('20-'34) Shutdown FB Culley 2	1.0% DSM Block (2020-2034)
2021			
2022			
2023			
2024			Solar PV[3] (1x50 MW)
2025			Solar PV (4x50 MW)
2026			
2027			
2028			
2029			
2030			
2031		Mkt Cap[4] (2MW)	
2032		Mkt Cap (6MW)	
2033		Mkt Cap (8MW)	
2034		Solar PV (1x50 MW)	
NPV[5]	$5,064,159	$5,049,163	$5,168,352
% Difference	0.0%	-0.3%	2.1%

[1] RPS = Renewable Portfolio Standard
[2] DSM = Demand Side Management
[3] PV = Photovoltaic
[4] Mkt Cap = Market Capacity Purchase
[5] Net Present Value inclusive of wholesale adjustment (2014 $)

High (large load) Demand Forecast (Growth Scenario 4)

Plans A-4, B-4 and C-4 represent the high (large load) demand forecast in combination with the three basic portfolio themes of "A"- Base (serve customers with existing resources & DSM), "B" – FB Culley 2 Unit Retirement Scenario and "C" – Renewable Portfolio Standard. It should be noted that no new capacity is required under this load forecast as can be seen in case A-4. However, the assumed retirement of Culley unit 2 in 2020 in conjunction with the increase in load drives a capacity addition in case B-4. The resource additions in plan C-4 are driven by the renewable energy constraints unique to the renewable portfolio scenario. However, the timing of the resources is slightly different due to interim renewable constraint in the renewable portfolio scenario.

This case represents the base set of assumptions and inputs as presented in the preceding sections of this chapter. For this analysis, no additional constraints were introduced that would prevent the planning model from selecting the set of future supply-side resources that resulted in the lowest NPV.

Table 10-6 shows the resource plan for the high (large load) demand forecast and the associated NPV's. Plan A-4 is the lowest cost plan under this load growth scenario, beating plans B-4 and C-4 by 1.9% and 2.5% respectively. Plans B-4 and C-4 reflect the capital expense of additional resources. These scenarios are significantly higher than plan A-4 in the near term. Note that all three plans are the same through 2018 where a DSM block is selected in the more expensive plan C-1.

Table 10-6 High (large load) Demand Forecast (Growth Scenario 4)

Energy Sales Case :	High (large load) Demand Forecast		
Scenario :	Base	FB Culley 2 Unit Retirement	RPS[1]
Plan ID :	Plan A4	Plan B4	Plan C4
2015			
2016			
2017			
2018			0.5% DSM[2] Block (2018-2034)
2019			
2020		Block of CCGT[3] (200 MW) Shutdown F.B Culley 2	0.5% DSM Block (2020-2034)
2021			
2022			
2023			
2024			Solar PV[4] (2x50 MW)
2025			Solar PV (4x50 MW)
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
NPV[5]	$5,156,487	$5,254,385	$5,283,860
% Difference	0.0%	1.9%	2.5%

[1] RPS = Renewable Portfolio Standard
[2] DSM = Demand Side Management
[3] CCGT = Combined Cycle Gas Turbine
[4] PV = Photovoltaic
[5] Net Present Value inclusive of wholesale adjustment (2014 $)

Integration Analysis Results Summary

As mentioned previously, the Strategist output is the lowest-cost plan for customers. The plan summary table 10-7 shows the costs for each plan A1-C4. Note that the costs represent the total present day value of serving Vectren customers under various portfolio mixes to meet customer demand for each scenario. The costs include capital for new resources, operating and maintenance costs, etc. for each plan over the 20-year forecast. Renewable Portfolio Standard (RPS) scenario plans were all the most expensive because they require new generation to be built and additional energy efficiency programs, which are paid for by customers, to meet the renewables requirement. Although no fuel is consumed by renewable resources, there are still costs associated with building and maintaining facilities. Renewables are intermittent resources, making them generally more expensive to help meet capacity requirements. Additionally, retiring FB Culley 2 prematurely, in the event of a large customer addition, could be very costly to customers. The cost of serving customers with existing resources, compared to retiring FB Culley 2 in 2020, were essentially the same under the low, base and high electric forecasts. Due to the risks associated with prematurely retiring FB Culley 2, discussed below in the Sensitivity and Risk Analysis section of this report, Vectren plans to serve customers with existing generation, plan A1 (Base electric forecast and Base scenario) in the near term. Vectren will conduct IRPs in 2016 and 2018. The plans are very similar or identical during the first few years. Therefore, no immediate action is required. The plans will be re-evaluated in future IRP cycles as various uncertainty factors are resolved over time.

Table 10-7 Plan Summary Table

		A	B	C
		Base Scenario	FB Culley 2 Unit Retirement Scenario	RPS Scenario
1	Base Demand Forecast	$4,874,614 0.0%	*$4,848,213* *-0.5%*	$4,991,616 2.4%
2	Low Demand Forecast	$4,771,789 0.0%	*$4,739,585* *-0.7%*	$4,871,859 2.1%
3	High (modeled) Demand Forecast	$5,064,159 0.0%	*$5,049,163* *-0.3%*	$5,168,352 2.1%
4	High (large load) Demand Forecast	*$5,156,487* *0.0%*	$5,254,385 1.9%	$5,283,860 2.5%

Note: Percent difference is reported on the same sales forecast basis
NPV = 2014 $000's @ 5.6%

SENSITIVITY AND RISK ANALYSIS

Each plan was subjected to additional risk sensitivities to determine which plan is the lowest cost over a wide range of possible future risks. As previously mentioned, resource modeling requires a large number of inputs and assumptions over a 20-year timeframe. It is impossible to precisely predict future prices of commodities such as fuel and other assumed economic factors such as carbon prices. Therefore, several future possibilities were considered. The 12 expansion plan scenarios were stress tested in regard to their sensitivity to variation in natural gas prices, coal prices, electric energy market prices, carbon prices, and capital costs of new resources. One additional stress test was added for a high regulation cost uncertainty. The parameters for these stress tests can be seen in table 10-8. The range of cost sensitivities for natural gas, coal and electric energy were stressed +/- 20%, which is consistent with the sensitivity

percentages used in the MISO Transmission Expansion Plan 15 (MTEP 15). The large MISO stakeholder constituency reaches consensus on these ranges; therefore, Vectren believes that these are reasonable ranges. At the suggestion of some stakeholders, Vectren used the Synapse 2013 mid case CO_2 pricing as the high sensitivity and the MTEP 15 CO_2 mid case as the low sensitivity. Capital costs for new resources were stressed +30/-10 percent as it is much more common throughout the industry to see cost underestimates than cost overestimates upon actual project completions. The high regulation cost was a stress test of adding the capital for a cooling tower at FB Culley in 2022.[1]

[1] [1] While Vectren continues to believe that it is unlikely that the state will require a cooling water tower retrofit at Culley under regulations recently finalized implementing Clean Water Act §316b, Vectren included this as a high cost sensitivity. Construction costs would commence starting in 2022, after the required ecological and technological study feasibility period.

Table 10-8 Sensitivity Summary Table (Used For Stress Tests)

Sensitivities	High	Low	Potential Sources
Natural Gas Forecasts	+20%	-20%	MTEP 15
Coal Forecast	+20%	-20%	MTEP 15
Market Energy Forecast	+20%	-20%	MTEP 15
CO_2 Forecast	$15.5/Ton	$10.3/Ton	Synapse, MTEP 15
Capital Cost	+30%	-10%	Burns and McDonnell Tech Assessment
High Regulation Cost*	$40m	-	Future Regulatory Scenario[1]

[1] While Vectren continues to believe that it is unlikely that the state will require a cooling water tower retrofit at Culley under regulations recently finalized implementing Clean Water Act §316b, Vectren included this as a high cost sensitivity. Construction costs would commence starting in 2022, after the required ecological and technological study feasibility period.

Stress Test of Base Demand Forecast (Growth Scenario 1)

Plan A-1 B-1 and C-1 stress test results are shown in table 10-9. Similarly to the results shows in table 10-3, plans A1 and B1 are essentially the same over a wide variety of possible future sensitivities. Plan C1 remains the most expensive.

Table 10-9 Stress Tests Results for Base Demand Forecast (Growth Scenario 1)

	Base (Plan A1)	FB Culley 2 Unit Retirement (Plan B1)	RPS (Plan C1)
Base	$4,874,614	$4,848,213	$4,991,616
High Gas	$4,908,570	$4,883,867	$5,024,377
Low Gas	$4,826,209	$4,797,668	$4,944,615
High Coal	$5,268,181	$5,221,310	$5,381,876
Low Coal	$4,471,184	$4,466,032	$4,591,643
High Market	$4,727,528	$4,737,505	$4,821,102
Low Market	$4,957,322	$4,895,134	$5,099,072
Low Carbon Price	$4,704,763	$4,681,858	$4,836,921
High Carbon Price	$5,336,590	$5,302,147	$5,415,470
High Capital Cost	$4,874,614	$4,848,213	$5,047,790
Low Capital Cost	$4,874,614	$4,848,213	$4,972,892
High Regulation Cost	$4,900,481	$4,867,614	$5,017,484

Stress Test of Low Demand Forecast (Growth Scenario 2)

Plan A-2 B-2 and C-2 stress test results are shown in table 10-10. Similarly to the results shows in table 10-4, plans A2 and B2 are essentially the same over a wide variety of possible future sensitivities. Plan C2 remains the most expensive.

Table 10-10 Stress Tests Results for Low Demand Forecast (Growth Scenario 2)

	Base (Plan A2)	FB Culley 2 Unit Retirement (Plan B2)	RPS (Plan C2)
Base	$4,771,789	$4,739,585	$4,871,859
High Gas	$4,804,936	$4,774,367	$4,904,004
Low Gas	$4,724,382	$4,690,021	$4,825,580
High Coal	$5,162,681	$5,110,118	$5,259,798
Low Coal	$4,371,289	$4,360,256	$4,474,450
High Market	$4,610,079	$4,613,296	$4,689,627
Low Market	$4,870,385	$4,803,750	$4,992,076
Low Carbon Price	$4,608,762	$4,579,376	$4,722,725
High Carbon Price	$5,215,962	$5,175,885	$5,282,560
High Capital Cost	$4,771,789	$4,739,585	$4,915,631
Low Capital Cost	$4,771,789	$4,739,585	$4,857,268
High Regulation Cost	$4,797,656	$4,758,986	$4,897,726

Stress Test of High (modeled) Demand Forecast (Growth Scenario 3)

Plan A-3 B-3 and C-3 stress test results are shown in table 10-11. Similarly to the results shows in table 10-5, plans A3 and B3 are essentially the same over a wide variety of possible future sensitivities. Plan C3 remains the most expensive.

Table 10-11 Stress Tests Results for High (modeled) Demand Forecast (Growth Scenario 3)

	Base (Plan A3)	FB Culley 2 Unit Retirement (Plan B3)	RPS (Plan C3)
Base	$5,064,159	$5,049,163	$5,168,352
High Gas	$5,099,475	$5,086,180	$5,202,306
Low Gas	$5,014,048	$4,997,322	$5,119,822
High Coal	$5,462,101	$5,425,041	$5,562,663
Low Coal	$4,655,886	$4,663,907	$4,763,874
High Market	$4,943,471	$4,956,522	$5,022,702
Low Market	$5,116,818	$5,076,415	$5,248,386
Low Carbon Price	$4,881,866	$4,876,097	$4,999,192
High Carbon Price	$5,563,573	$5,525,040	$5,628,969
High Capital Cost	$5,064,159	$5,050,009	$5,224,526
Low Capital Cost	$5,064,159	$5,048,881	$5,149,626
High Regulation Cost	$5,090,027	$5,068,564	$5,194,219

Stress Test of High (large load) Demand Forecast (Growth Scenario 4)

Plan A-4 B-4 and C-4 stress test results are shown in table 10-12. Similarly to the results shows in table 10-6, plan A4 is significantly less expensive in the near term than plans B4 and C4.

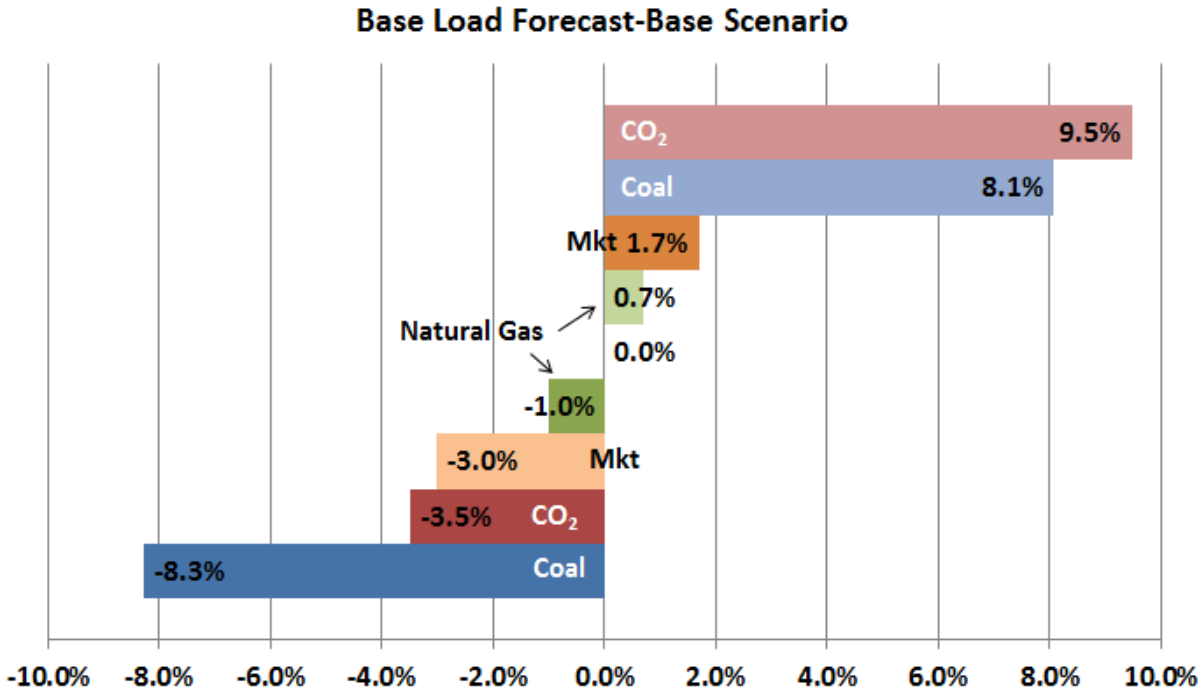
Table 10-12 Stress Tests Results for High (large load) Demand Forecast (Growth Scenario 3)

	Base (Plan A4)	FB Culley 2 Unit Retirement (Plan B4)	RPS (Plan C4)
Base	$5,156,487	$5,254,385	$5,283,860
High Gas	$5,192,745	$5,317,261	$5,318,391
Low Gas	$5,105,576	$5,163,552	$5,234,683
High Coal	$5,556,624	$5,646,923	$5,679,926
Low Coal	$4,745,742	$4,853,216	$4,877,383
High Market	$5,049,403	$5,098,566	$5,147,775
Low Market	$5,194,651	$5,328,227	$5,353,361
Low Carbon Price	$4,970,102	$5,093,626	$5,112,573
High Carbon Price	$5,665,492	$5,711,718	$5,749,275
High Capital Cost	$5,156,487	$5,322,627	$5,441,585
Low Capital Cost	$5,156,487	$5,231,638	$5,240,428
High Regulation Cost	$5,182,354	$5,273,786	$5,309,727

Relative Influence of Stress Test Factors

The relative influence of the stress tests on the net present values can be seen in table 10-13.

Table 10-13 Relative Influence of Stress Tests on Net Present Values



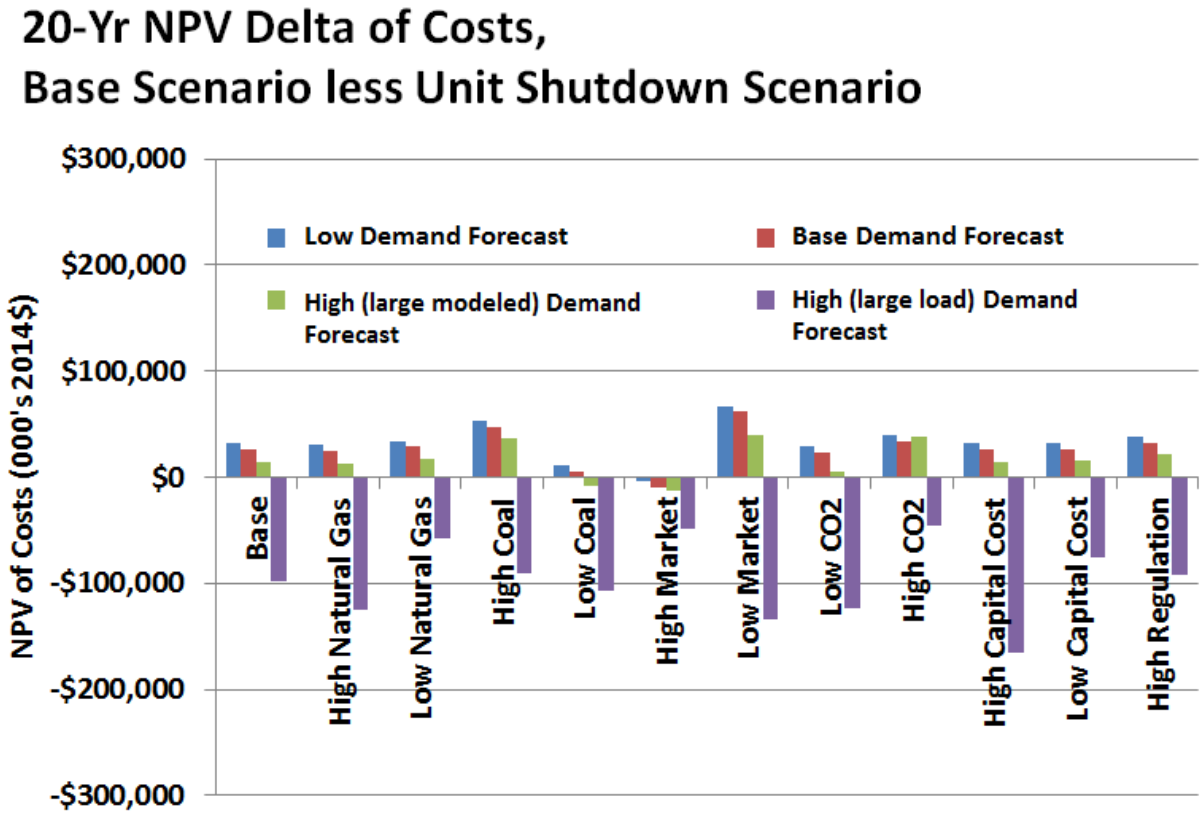
Risk Comparison

Under most risk factors, the cost of continuing operation of FB Culley or retirement in 2020 are essentially the same. As illustrated below in Table 10-14, the cost risk to customers if Vectren prematurely retires F.B. Culley 2 is potentially large under the high (large load) demand forecast.

Table 10-14 shows the risk comparison across all sensitivities and sales forecasts for the base scenario compared to the coal retirement scenario. This graph illustrates that the differences across three of the four sales forecasts are relatively small compared to the large savings in the high (large load) demand forecast case. Stated differently, the positive bars represent the extra cost of not retiring FB Culley 2 under 3 of the 4

demand scenarios. The negative bars represent the savings under 1 of the 4 sales scenarios by not retiring FB Culley 2 in 2020. The high (large load) growth scenario savings are much greater across all sensitivities by not retiring a unit. Vectren is actively working to attract new industrial customers through economic development activities in southwestern Indiana. If a large customer chooses to locate within the Vectren electric service area, it will be significantly less expensive to serve that additional load with existing resources in the near term.

Table 10-14 Comparison of Risks



Therefore, there are significant risks to retiring Culley unit 2 in the next few years. Vectren is making no decision at this time on a retirement date for several reasons. The graph above illustrates the risk of the high large load addition. Other significant risks include how the state of Indiana implements the Clean Power Plan, load uncertainties,

and potential MISO shortfalls. There is little clarity on how Indiana intends to implement CO_2 guidelines. Depending on the direction that is taken, the plan may vary. Second, one of Vectren's largest customers is still finalizing plans for their co-generation unit. Vectren needs to better understand how this will affect the load forecast. Finally, with several coal plants shutting down within the MISO market, there is potential that not enough generation will be available to reliably serve the overall market. A decision about the assumed retirement of FB Culley 2 in 2020 in scenarios B1-B4 will not be made until near-term risk factors become clearer.

CONCLUSION

Based on Vectren's electric demand forecast, which includes cost effective DSM energy efficiency programs for customers, Vectren does not require additional resources. The IRP analysis indicates it is essentially the same cost to continue to operate FB Culley 2 or retire it in the near future. The decision to retire this unit is subject to a number of risks and uncertainties. Vectren is making no decision at this time on a retirement date.

As mentioned in the Risk Analysis section of this report, there are four major risks of retiring FB Culley 2 in the next few years:

1. How Indiana intends to implement CO_2 guidelines, the EPA's Clean Power Plan (111d)
2. Uncertainty about customer load due to the installation of a large co-generation unit
3. The possibility of a new large customer addition
4. Uncertainty around potential capacity shortfalls within the MISO market

Based on the risk associated with retiring FB Culley 2, Vectren will keep plan A-1 as the plan of choice in the near term, but will continue to evaluate the changing technology, environmental and regulatory developments, as well as customer costs and

reliability needs. More time and analysis is needed to make a decision on the timing of retiring FB Culley 2. Note that there will be two more IRPs prepared prior to 2020.

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CHAPTER 11

ACTION PLAN

INTRODUCTION

These are the next steps the organization will take to achieve a reasonable long-term cost to retail customers with full consideration of the complex issues facing the industry in the next few years.

SUPPLY-SIDE RESOURCES

The overall objective of this study and review is to ensure that Vectren is properly positioned to meet its obligation to serve the needs of its Indiana retail customer base. Over the next several years, Vectren will continue to monitor changing market factors and risks including, but not limited to, increased environmental regulations including the EPA Clean Power Plan, large customer load, fuel price volatility, escalation of capital costs, increased emphasis on conservation measures, demand response, Smart Grid/AMI, and RTO related developments, particularly the possibility of MISO shortfalls. These items will be monitored both for their potential impact on future capacity needs and their impact on the operation of existing assets.

Vectren projects to have the generating capacity needed to meet the needs of its customers without adding any additional assets in all scenarios. All 12 plans explored are very similar or identical during the first few years. No immediate action is required. Vectren will conduct additional analysis, including another IRP in 2016. A decision about the assumed retirement of FB Culley 2 in 2020 will not be made until near term risk factors become clearer.

DEMAND-SIDE RESOURCES

Vectren plans to continue to pursue DSM, energy efficiency, and demand response opportunities by working through collaborative efforts with the IURC and OUCC. Vectren will continue to implement the 2015 DSM Plan as filed under Cause No. 44495, which was recently approved by the Commission. The programs outlined in the 2015 DSM Plan are designed to cost effectively reduce energy use and electric demand by approximately 1% of eligible retail sales. While Vectren's current resources are

adequate to meet the needs of its customers, Vectren believes that conservation is in their customers' best interest. Helping customers learn to conserve energy will benefit customers through lower bills, the environment through lower emissions, and rates through the reduced need for additional system capacity in the future.

Vectren is in the process of developing a three-year Action Plan for 2016-2018 electric DSM programs. The programs outlined in this three-year Action Plan will be designed to reduce energy use by approximately 1– 1.5% of eligible retail sales. There are several variables that currently exist that may have impact on this planning process. The EPA Clean Power Plan proposal, Federal appliance and equipment minimum efficiency standards and state legislation relating to energy efficiency could all impact the savings goals for the next three years. Vectren is currently monitoring such rules and regulations and will continue to incorporate these factors into this planning process, as required.

Vectren will closely monitor trends regarding Smart Grid/AMI throughout the country. Vectren will work collaboratively with key stakeholders to determine the appropriate implementation strategy for Smart Grid/AMI in the Vectren territory.

TRANSMISSION AND DISTRIBUTION

Vectren will work closely with MISO to determine those transmission projects that will improve overall grid reliability within its service territory and those in the surrounding area. Vectren will implement system upgrades as needed to ensure reliable service to its customers. In addition, ongoing internal studies will monitor additions of industrial and commercial load in different locations within the Vectren service territory.

Detailed budgets for the short-term plan will be developed during Vectren's normal budgeting process.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

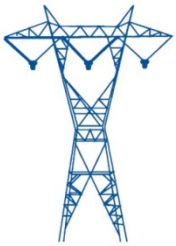
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 108
Vectren 2016 IRP

RECEIVED
December 19, 2016
INDIANA UTILITY
REGULATORY COMMISSION

2016 Integrated Resource Plan



VECTREN
Live Smart

By
Southern Indiana Gas and Electric Company
d/b/a Vectren Energy Delivery of Indiana, Incorporated

December 16, 2016

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IRP Proposed Draft Rule Requirements Cross Reference Table

Rule Reference	Rule Description	Report Reference (Outline Section)
170 IAC 4-7-4	**Methodology and documentation requirements**	
	(a) The utility shall provide an IRP summary document that communicates core IRP concepts and results to non-technical audiences. (1) The summary shall provide a brief description of the utility's existing resources, preferred resource portfolio, short term action plan, key factors influencing the preferred resource portfolio and short term action plan, and any additional details the commission staff may request as part of a contemporary issues meeting. The summary shall describe, in simple terms, the IRP public advisory process, if applicable, and core IRP concepts, including resource types and load characteristics. (2) The utility shall utilize a simplified format that visually portrays the summary of the IRP in a manner that makes it understandable to a non-technical audience. (3) The utility shall make this document readily accessible on its website.	Executive Summary and a separate document on www.vectren.com/irp
	(b) An IRP must include the following: (1) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.	Included throughout the IRP

Rule Reference	Rule Description	Report Reference (Outline Section)
170 IAC 4-7-4 Cont.	(2) The data sets, including data sources, used to establish base and alternative forecasts. A third party data source may be referenced. The reference must include the source title, author, publishing address, date, and page number of relevant data. The data sets must include an explanation for adjustments. The data must be provided on electronic media, and may be submitted as a file separate from the IRP, or as specified by the commission.	Included throughout the IRP and Technical Appendix
	(3) A description of the utility's effort to develop and maintain a data base of electricity consumption patterns, by customer class, rate class, NAICS code, and end-use. The data base 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.	10.1.1.1; Technical Appendix Attachment 4.1 2016 Long-Term Electric Energy and Demand Forecast Report
	(4) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.	10.1.2
	(5) A discussion of distributed generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting.	4.4.1; 4.4.2; 4.4.3

Rule Reference	Rule Description	Report Reference (Outline Section)
	(6) A complete discussion of the alternative forecast scenarios developed and analyzed, including a justification of the assumptions and modeling variables used in each scenario.	6.1; 6.2
	(7) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.	8.2.10
	(8) A discussion of how the utility's emission allowance inventory and procurement practices for any air emission regulated through an emission allowance system have been taken into account and influenced the IRP development.	1.3.1.1; 7.3.4; 10.2; 10.2.1
	(9) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	2.2; 7.2.1; 8
170 IAC 4-7-4 Cont.	(10) A brief description and discussion within the body of the IRP focusing on the utility's Indiana jurisdictional facilities with regard to the following components of FERC Form 715: (A) 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 simulation must include the capability of meeting the standards of the North American Electric Reliability Corporation (NERC).	5.4; 10.6

Rule Reference	Rule Description	Report Reference (Outline Section)
	(C) Reliability criteria for transmission planning as well as the assessment practice used. The information and discussion must include the limits set of its transmission use, its assessment practices developed through experience and study, and certain operating restrictions and limitations particular to it. (D) Various aspects of any joint transmission system, ownership, and operations and maintenance responsibilities as prescribed in the terms of the ownership, operation, maintenance, and license agreement.	
	(11) An explanation of the contemporary methods utilized by the utility in developing the IRP, including a description of the following:	
	(A) Model structure and reasoning for use of particular model or models in the utility's IRP.	4.3; 5.2.3.3; 7.1.1.1; 7.2.1.1; 10.5
	(B) The utility's effort to develop and improve the methodology and inputs for its:	1.2.2
	(i) forecast;	4.2; 4.4.2; 6.1; 6.2
	(ii) cost estimates;	5.2
	(iii) treatment of risk and uncertainty; and	2; 6.2; 7; 8.1; 8.2
	(iv) evaluation of a resource (supply-side or demand-side) alternative's contribution to system wide reliability. The measure of system wide reliability must cover the reliability of the entire system, including:	
	(AA) transmission; and	5.4.3; 8.2.7; 10.6
	(BB) generation.	5.1.5.2; 7.3.5; 8.2.3

Rule Reference	Rule Description	Report Reference (Outline Section)
170 IAC 4-7-4 Cont.	(12) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. Avoided cost shall include, but is not limited to, the following: (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 fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.	10.2.4
	(13) The actual demand for all hours of the most recent historical year available, which shall be submitted electronically and may be a separate file from the IRP. For purposes of comparison, a utility must maintain three (3) years of hourly data.	Technical Appendix Attachment4.2 2015 Vectren Hourly System Load Data
	(14) Publicly owned utilities shall provide a summary of the utility's: (A) most recent public advisory process; (B) key issues discussed; (C) how they were addressed by the utility.	3; Technical Appendix Attachment 3.1 Stakeholder Materials
170 IAC 4-7-5	**Energy and demand forecasts**	
	(a) An electric utility subject to this rule shall prepare an analysis of historical and forecasted levels of peak demand and energy	

Rule Reference	Rule Description	Report Reference (Outline Section)
	usage which includes the following:	
	(1) Historical load shapes, including, but not limited to, the following:	Technical Appendix Attachment 4.1 2016 Long-Term Electric Energy and Demand Forecast Report
	(A) Annual load shapes.	
	(B) Seasonal load shapes.	
	(C) Monthly load shapes.	
	(D) Selected weekly and daily load shapes. Daily load shapes shall include, at a minimum, summer and winter peak days and a typical weekday and weekend day.	
	(2) Historical and projected load shapes shall be disaggregated, to the extent possible, by customer class, interruptible load, and end-use and demand-side management program.	
	(3) Disaggregation of historical data and forecasts by customer class, interruptible load, and end-use where information permits.	Technical Appendix Attachment 4.1 2016 Long-Term Electric Energy and Demand Forecast Report; Technical Appendix Attachment 7.2 Balance of Loads and Resources
	(4) Actual and weather normalized energy and demand levels.	10.1.3
170 IAC 4-7-5 Cont.	(5) A discussion of all methods and processes used to normalize for weather.	10.1.3; 10.1.1.3
	(6) A minimum twenty (20) year period for energy and demand forecasts.	4.5
	(7) An evaluation of the performance of energy and demand forecasts for the previous ten (10) years, including, but not limited to, the following: (A) Total system.	10.1.3

Rule Reference	Rule Description	Report Reference (Outline Section)
	(B) Customer classes or rate classes, or both. (C) Firm wholesale power sales.	
	(8) Justification for the selected forecasting methodology.	Technical Appendix Attachment 4.1 2016 Long Term Electric Energy and Demand Forecast
	(9) For purposes of subdivisions (1) and (2), a utility may use utility specific data or more generic data, such as, but not limited to, the types of data described in section 4(b)(2) of this rule.	
	(b) A utility shall provide at least three (3) alternative forecasts of peak demand and energy usage. At a minimum, the utility shall include high, low, and most probable energy and peak demand forecasts based on alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (4) Changes in technology. (5) Behavioral factors affecting customer consumption. (6) State and federal energy policies. (7) State and federal environmental policies.	4.5; 6.2.2.2
170IAC 4-7-6	**Resource Assessment**	
	(a) The utility shall consider continued use of an existing resource as a resource alternative in meeting future electric service requirements. The utility shall provide a description of the utility's existing electric power resources that must include, at a minimum, the following information:	5.1
	(1) The net dependable generating capacity of the system and each generating unit.	5.1

Rule Reference	Rule Description	Report Reference (Outline Section)
	(2) The expected changes to existing generating capacity, including, but not limited to, the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	5.1; 7
	(3) A fuel price forecast by generating unit.	6.1
170IAC 4-7-6 Cont.	(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 each existing fossil fueled generating unit.	10.2
	(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 transmission losses, congestion, and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network. (D) An assessment of the transmission component of avoided cost.	10.6
	(6) A discussion of demand-side programs, including existing company-sponsored and government-sponsored or mandated energy conservation or load	5.1.4; 5.1.5; Technical Appendix Attachment 5.1 Vectren South

Rule Reference	Rule Description	Report Reference (Outline Section)
	management programs available in the utility's service area and the estimated impact of those programs on the utility's historical and forecasted peak demand and energy.	Electric 2016-2017 DSM Plan
	The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall also be provided for each year of the planning period.	
	(b) 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. For a utility-sponsored program identified as a potential demand-side resource, the utility's IRP shall, at a minimum, include the following:	5.1.5; 5.2.3; 5.2.4
	(1) A description of the demand-side program considered.	5.2.3; 5.2.4
	(2) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to resources under consideration such as project life and seasonal operation.	10.3.4
	(3) The customer class or end-use, or both, affected by the program.	5.1.4; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan

Rule Reference	Rule Description	Report Reference (Outline Section)
	(4) A participant bill reduction projection and participation incentive to be provided in the program.	Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
170IAC 4-7-6 Cont.	(5) A projection of the program cost to be borne by the participant.	Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(6) Estimated energy (kWh) and demand (kW) savings per participant for each program.	Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(7) The estimated program penetration rate and the basis of the estimate.	Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(8) The estimated impact of a program on the utility's load, generating capacity, and transmission and distribution requirements.	5.1.4; 5.2.3; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(c) A utility shall consider a range of supply-side resources including cogeneration and nonutility generation as an alternative in meeting future electric service requirements. This range shall include commercially available resources or resources the director may request as part of a contemporary issues technical conference. The utility's IRP shall include, at a minimum, the following:	5
	(1) Identify and describe the resource considered, including the following:	5; 10.6

Rule Reference	Rule Description	Report Reference (Outline Section)
	(A) Size (MW).	5
	(B) Utilized technology and fuel type.	5
	(C) Additional transmission facilities necessitated by the resource.	5.4.3
	(2) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	9.2.4
	(d) A utility shall consider new or upgraded transmission facilities as a resource in meeting future electric service requirements, including new projects, efficiency improvements, and smart grid resources. The IRP shall, at a minimum, include the following: (1) A description of the timing and types of expansion and alternative options considered. (2) The approximate cost of expected expansion and alteration of the transmission network. (3) A description of how the IRP accounts for the value of new or upgraded transmission facilities for the purposes of increasing needed power transfer capability and increasing the utilization of cost effective resources that are geographically constrained.	5.4.3
170IAC 4-7-6 Cont.	(4) A description of how: (A) IRP data and information are used in the planning and implementation processes of the RTO of which the utility is a member; and (B) RTO planning and implementation processes are used in and affect the IRP.	1.3.7; 4;6.1.3; 10.6.2
170 IAC 4-7-7	**Selection of future resources**	

Rule Reference	Rule Description	Report Reference (Outline Section)
	(a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in sections 6(b) through 6(c) 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, but not limited to, a resource summary table. The following information: (1) Significant environmental effects, including the following: (A) Air emissions. (B) Solid waste disposal. (C) Hazardous waste and subsequent disposal. (D) Water consumption and discharge.	10.2; Technical Appendix Confidential Attachment 1.2 2016 Vectren Technology Assessment Summary Table
	(2) An analysis of how existing and proposed generation facilities conform to the utility-wide plan to comply with existing and reasonably expected future state and federal environmental regulations, including facility-specific and aggregate compliance options and associated performance and cost impacts.	1.3.1; 6.1; 6.2; 7.3.4; 8.2.2; 10; Technical Appendix Attachment 3.1 Stakeholder Materials
	(b) Integrated resource planning includes one (1) or more tests used to evaluate the cost effectiveness of a demand-side resource option. A cost-benefit analysis must be performed using the following tests except as provided under subsection (e): (1) Participant. (2) Ratepayer impact measure (RIM). (3) Utility cost (UC). (4) Total resource cost (TRC). (5) Other reasonable tests accepted by the commission.	5.2.3.7; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan

Rule Reference	Rule Description	Report Reference (Outline Section)
	(c) A utility is not required to express a test result in a specific format. However, a utility must, in all cases, calculate the net present value of the program impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the discount rate used in the test.	5.2.3.7; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(d) A utility is required to:	
	(1) specify the components of the benefit and the cost for each of the major tests; and	5.2.3.7; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(2) identify the equation used to express the result.	5.2.3.7; Technical Appendix Attachment: 5.1 Vectren South Electric 2016-2017 DSM Plan
170 IAC 4-7-7 Cont.	(e) If a reasonable cost-effectiveness analysis for a demand-side management program cannot be performed using the tests in subsection (b), where it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.	5.2.3.7; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(f) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.	N/A
170 IAC 4-7-8	**Resource integration**	
	(a) The utility shall develop candidate resource portfolios from the selection of future resources in section 7 and provide a description of its process for developing its candidate resource portfolios.	7.1; 3.2; Technical Appendix Attachment 3.1 Stakeholder Materials

Rule Reference	Rule Description	Report Reference (Outline Section)
	(b) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and provide, at a minimum, the following information:	8.2
	(1) Describe the utility's preferred resource portfolio.	8.2
	(2) Identify the variables, standards of reliability, and other assumptions expected to have the greatest effect on the preferred resource portfolio.	8.2
	(3) Demonstrate that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis.	5; 6; 7; 8.2
	(4) Demonstrate that the preferred resource portfolio utilizes, to the extent practical, all economical load management, demand side management, technology relying on renewable resources, cogeneration, distributed generation, energy storage, transmission, and energy efficiency improvements as sources of new supply.	8.2
	(5) Discuss the utility's evaluation of targeted DSM programs including their impacts, if any, on the utility's transmission and distribution system for the first ten (10) years of the planning period.	5; 8.2; 10.3; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
170 IAC 4-7-8 Cont.	(6) Discuss the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio. The discussion of the preferred resource portfolio shall include, where appropriate, the following: (A) Operating and capital costs. (B) The average cost per kilowatt-hour, which must be consistent with the electricity price assumption used to forecast the utility's	8.2; 9.2.5; 10; Technical Appendix Confidential Attachment 7.3 Portfolio Input-Output Report

Rule Reference	Rule Description	Report Reference (Outline Section)
	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.	
	(7) Demonstrate how the preferred resource portfolio balances cost minimization with cost effective risk and uncertainty reduction, including the following. (A) Identification and explanation of assumptions. (B) Quantification, where possible, of assumed risks and uncertainties, which may include, but are not limited to: See below. (i) regulatory compliance; (ii) public policy; (iii) fuel prices; (iv) construction costs; (v) resource performance; (vi) load requirements; (vii) wholesale electricity and transmission prices; (viii) RTO requirements; and (ix) technological progress. (C) An analysis of how candidate resource portfolios performed across a wide range of potential futures.	7; 8.2; Technical Appendix Attachment 3.1 Stakeholder Materials
	(D) The results of testing and rank ordering the candidate resource portfolios by the present value of revenue requirement and risk metric(s). The present value of revenue requirement shall be stated in total dollars and in dollars per kilowatt-hour delivered, with the	7.3.1; 10.5.2; Technical Appendix Attachment 3.1 Stakeholder Materials

Rule Reference	Rule Description	Report Reference (Outline Section)
	discount rate specified.	
170 IAC 4-7-8 Cont.	(E) An assessment of how robustness factored into the selection of the preferred resource portfolio.	2; 7; 8
	(8) Demonstrate, to the extent practicable and reasonable, that the preferred resource portfolio incorporates a workable strategy for reacting to unexpected changes. A workable strategy is one that allows the utility to adapt to unexpected circumstances quickly and appropriately. Unexpected changes include, but are not limited to, the following: See below. (A) The demand for electric service. (B) The cost of a new supply-side or demand-side technology. (C) Regulatory compliance requirements and costs. (D) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	7; 8
170 IAC 4-7-9	**Short term action plan**	
	Sec. 9. A short term action plan shall be prepared as part of the utility's IRP, and shall cover each of the three (3) years beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(b)(8), where the utility must take action or incur expenses during the three (3) year period. The short term action plan must include, but is not limited to, the following:	9

Rule Reference	Rule Description	Report Reference (Outline Section)
	(1) A description of each resource in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective. (2) The implementation schedule for the preferred resource portfolio. (3) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts. (4) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually transpired.	

List of Acronyms/Abbreviations

AAB	Advanced Automotive Batteries
ABB	AB Brown Generating Station
AC	Alternating Current
AUPC	Average Use Per Customer
B	Water Heating Service – Closed to new customers
BAGS	Broadway Avenue Generating Station
Bat	Battery
BES	Bulk Electric System
Bn	Billion
BNEF	Bloomberg New Energy Finance
BOS	Balance of System
BTMG	Behind The Meter Generation
Btu	British Thermal Unit
C&I	Commercial and Industrial
CAA	Clean Air Act
CAC	Citizens Action Coalition
CAES	Compressed Air Energy Storage
CAGR	Compound Annual Growth Rate
CAPP	Central Appalachian
CC	Combined Cycle
CC CT	Combined Cycle Combustion Turbine
CC ST	Combined Cycle Steam Turbine
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Day
CEMAC	Clean Energy Manufacturing Analysis
CEMS	Continuous Emissions Monitoring System
CFL	Compact Fluorescent Lighting
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
Comm	Commercial
CPCN	Certificate of Public Need and Necessity
CPP	Clean Power Plan
CSA	Coordinated Seasonal Transmission Assessment
CSAPR	Cross State Air Pollution Rule
CVR	Conservation Voltage Reduction
CWIS	Cooling Water Intake Structures
DB	Deutsche Bank
DC	Direct Current
DG	Distributed Generation
DGS	Demand General Service
DLC	Direct Load Control

List of Acronyms/Abbreviations (Cont.)

DOE	U.S. Department of Energy
DR	Demand Response
DSI	Dry Sorbent Injection
DSM	Demand Side Management
DSMA	Demand Side Management Adjustment
EEFC	Energy Efficiency Funding Component
EERE	Energy Efficiency and Renewable Energy
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines
EM&V	Evaluation, measurement, and Verification
EOP	Emergency Operating Procedure
EPA	U.S. Environmental Protection Agency
EPC	Engineering Procurement and Construction
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
EV	Electric Vehicle
EVA	Energy Ventures Analysis, Inc.
FBC	FB Culley Generating Station
FBC3	FB Culley Unit 3
FDNS	Fixed Slope Decoupled Newton-Raphson
FERC	Federal Energy Regulatory Commission
FF	Fabric Filter
FGD	Flue Gas Desulfurization
GDP	Gross Domestic Product
GE	General Electric
GPCM	Gas Pipeline Competition Model
GPS	Global Positioning System
GS	General Service
GT	Gas Turbine
GTM	Green Tech Media
GW	Gigawatt
GWh	Gigawatt Hour
H_2SO_4	Hydrochloric Acid
HAP	Hazardous Air Pollutants
HCl	Hydrochloric Acid
HDD	Heating Degree Days
Hg	Mercury
HHV	Higher Heating Value
HLF	High Load Factor
HRSG	Heat Recovery Steam Generator
HUM	Humidity

List of Acronyms/Abbreviations (Cont.)

I&M	Indiana Michigan Power
IC	Internal Combustion
ICAP	Installed Capacity
IDEM	Indiana Department of Environmental Management
IGCC	Integrated Gasification Combined Cycle
ILB	Illinois Basin
Ind	Industrial
IPL	Indianapolis Power and Light Company
IPP	Independent Power Producers
IRP	Integrated Resource Plan
ISO	Independent System Operator
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
lb	Pound
LBA	Load Balancing Area
LGE/KU	Louisville Gas and Electric/Kentucky Utilities
LIB	Lithium-ion Battery
Li-ion	Lithium-ion
LMP	Local Marginal Pricing
LMR	Load Modifying Resources
LMR	Load Management Receivers
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LP	Large Power
LRR	Local Reliability Requirement
LRZ	Local Resource Zone
LSE	Load Serving Entity
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
MEP	Market Efficiency Project
MILP	Mixed Integer Linear Programming
MISO	Midcontinent Independent System Operator
MISO Tariff	Open Access Transmission, Energy, and Operating Reserve Markets Tariff
MLA	Municipal Levee Authority
MMBtu	One Million British Thermal Unit
MMWG	Multiregional Modeling Working Group
MPSC	Missouri Public Service Commission
MSA	Metropolitan Statistical Area

List of Acronyms/Abbreviations (Cont.)

MTEP	MISO Transmission Expansion Plan
MVP	Multi Value Project
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standard
NAICS	North American Industry Classification System
NAPP	Northern Appalachia
NEGT	Northeast Gas Turbine
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
NW Council	Northwest Power and Conservation Council
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
OMS	Organization of MISO States
ORSANCO	Ohio River Valley Sanitation Commission
OSS	Off Season Service
OUCC	Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PI	Personal Income
PIRA	PIRA Energy Group
PJM	Pennsylvania New Jersey Maryland Interconnection LLC
PM	Particulate Matter
PPA	Purchase Power Agreement
PPT	Parts Per Trillion
PRA	Planning Resource Auction
PRB	Powder River Basin
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PSEG	Public Service Electric and Gas
PSIG	Pounds Per Square Inch Gauge
PTI PSS/E	Power Technologies Incorporated's Power System Simulator Program for Engineers
PUC	Public Utility Commission
PV	Photovoltaic

List of Acronyms/Abbreviations (Cont.)

Res	Residential
RF	ReliabilityFirst
RGGI	Regional Greenhouse Gas Initiative
RIM	Ratepayer Impact Measure
RS	Residential Service
RTO	Regional Transmission Operator
SAE	Statistically Adjusted End-use
SB	Senate Bill
SBS	Sodium Bisulfite
SCADA	Supervisory Control and Data Acquisition
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SD	Standard Deviation
SDE	Stochastic Differential Equation
SEA	Senate Enrolled Act
SEIA	Solar Energy Industries Association
SGS	Small General Service
SIGECO	Southern Indiana Gas and Electric Company
SIP	State Implementation Plan
SIS	System Impact Study
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
STD Dev	Standard Deviation
SVC	Static Var Compensator
T&D	Transmission and Distribution
TBtu	One Trillion British Thermal Unit
TRC	Total Resource Cost
TVA	Tennessee Valley Authority
UC	Utility Cost
UCAP	Unforced Capacity
UCT	Utility Cost Test
UE	University of Evansville
UPC	Use Per Customer
V	Volt
VAR	Volt-Amp Reactance
VEDO	Vectren Energy Delivery of Ohio
VOM	Variable Operation and Maintenance
VUHI	Vectren Utility Holdings Inc.
Wdc	Watt Direct Current
WN	Weather Normalized
WTE	Waste To Energy

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Executive Summary (Non-Technical Summary)

I. Introduction

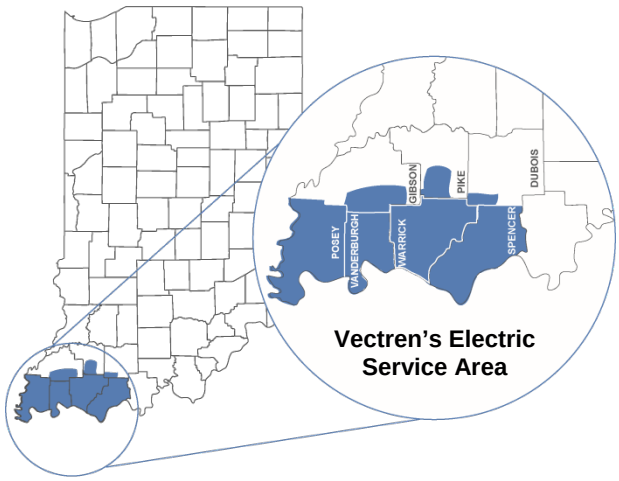
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren") engaged in a planning exercise during 2016 to evaluate its electric supply needs over a 20-year planning horizon. That exercise culminated in this 2016 Integrated Resource Plan ("IRP"). This planning exercise evaluated anticipated customer demand for electric supply in Vectren's electric service territory and identified resources to satisfy that demand. It included public meetings designed to solicit input from stakeholders about modeling assumptions. The evaluation then sought to use the inputs to estimate the total 20-year net present value cost, in 2016 dollars, of the various resource plan options to satisfy that demand. The analysis factored in the risk with heavy emphasis on evaluating the plan in the face of multiple possible future states. The future could bring various government regulations, varying fuel prices, varying resource costs, etc. This analysis was used to identify the portfolio of electric supply and demand side resources that best balances reliability, cost, risk, and sustainability.

Based on this planning process, Vectren has selected a preferred portfolio plan that balances the energy mix for its generation portfolio with the addition of a new combined cycle gas turbine facility and solar power plants and significantly reduces its reliance on coal-fired electric generation. Vectren's preferred portfolio reduces its cost of providing service to customers over the next 20 years by approximately $60 million as compared to continuing with its existing generation fleet. Additionally, the preferred portfolio reduces carbon dioxide output by approximately 46% by 2024 from 2012 levels, exceeding the Clean Power Plan (CPP) regulation, which requires a 32% reduction by 2030. When considering 2005 levels, this would be a reduction of almost 60%. Importantly, from a risk perspective, Vectren will continue to evaluate its preferred portfolio plan in future IRPs to ensure it remains the best option to meet customer needs.

What follows is a summary of the process Vectren engaged in to identify this portfolio, focusing on Vectren's operations, an explanation of the planning process, and a summary of the preferred portfolio.

II. Vectren Overview

Vectren provides energy delivery services to over 144,000 electric customers and approximately 110,000 gas customers located near Evansville in southwestern Indiana. In 2015, approximately 50% of electric sales were made to large (primarily industrial) customers, 26% were made to residential customers and 24% were made to small commercial customers.



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

Unit	Installed Capacity ICAP (MW)	Primary Fuel	Unit Age	Coal Unit Environmental Controls[1]
AB Brown 1	245	Coal	1979	Yes
AB Brown 2	245	Coal	1986	Yes
FB Culley 2	90	Coal	1966	Yes
FB Culley 3	270	Coal	1973	Yes
Warrick 4	150	Coal	1970	Yes
AB Brown 3	80	Gas	1991	
AB Brown 4	80	Gas	2002	
BAGS 2	65	Gas	1981	
Northeast 1&2	20	Gas	1963 / 1964	
Blackfoot[2]	3	Landfill Gas	2009	
Fowler Ridge	50	Wind PPA	2010	
Benton County	30	Wind PPA	2007	

[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) except FB Culley 2.
[2] The Blackfoot landfill gas generator is connected at the distribution level.

III. Integrated Resource Plan

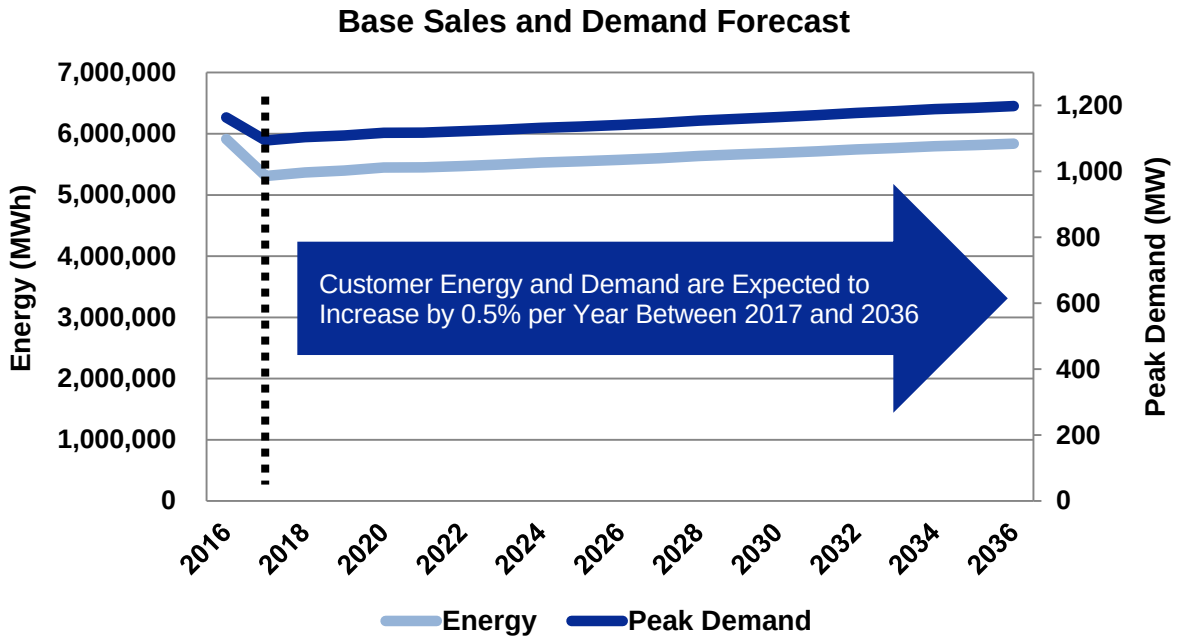
Vectren periodically submits IRPs to the Indiana Utility Regulatory Commission (IURC or Commission) as required by IURC rules. The IRP describes the analysis process used to determine the best mix of generation and energy efficiency resources (resource portfolio) to meet customers' needs for reliable, low cost, environmentally acceptable 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 finalize the detailed course.

Vectren considered input/perspectives from stakeholders, including but not limited to Vectren residential, commercial and industrial customers, regulators, elected officials, customer advocacy groups, environmental advocacy groups, and Vectren shareholders. Throughout the IRP analysis, Vectren placed an emphasis on reliability, customer cost, risk, and sustainability.

A. Customer Energy Needs

An IRP begins by evaluating customers' need for electricity over the 20-year planning horizon. Vectren 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. Both are important considerations in the IRP. While Vectren purchases some power from the market, Vectren is required to have enough generation and energy efficiency resources available to meet expected customers' annual peak demand plus additional reserve resources to help maintain reliability. Reserve resources are necessary to minimize the chance of rolling black outs; moreover, as a MISO (Midcontinent Independent System Operator) member, Vectren must comply with MISO established reserve requirements.

Vectren 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, and weather. In 2017, a large customer is expected to commence generating a large portion of its energy needs with its own generation, which will decrease Vectren's overall energy and demand forecast between 2016 and 2017. Beyond 2017, these forecasts, which do not include future energy company sponsored energy efficiency, indicate that overall customer energy and demand are expected to grow by 0.5% per year.



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. Vectren considered both new and existing resource options. Burns and McDonnell, a well-respected engineering firm, provided Vectren with detailed information on each of the generating resources, including but not limited to, capital costs, operating costs, operating characteristics, how much generation to expect under various conditions, plant emissions, etc. These costs provide a complete picture of the cost of various resource options over the entire 20-year period. Numerous costs impact supply resources, but the following that had a particularly significant impact on the IRP were EPA regulations, low natural gas prices, and renewable costs.

Energy Efficiency/Demand Response

Natural Gas, including CHP

Coal

Renewables, Wind & Solar

Battery Storage

Through investments in emissions control equipment over the past 15 years, Vectren's power system became one of the best controlled for emissions in the Midwest.

i. Environmental Protection Agency (EPA) Regulations

While Vectren's coal plants are controlled to meet or exceed current regulations for Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_x), mercury, and particulate matter (dust), new EPA regulations require Vectren, and other utilities around the country, to make incremental investments in coal-fired generation plants if they are to continue operating them. The EPA regulation adoption process begins with a notice of proposed rulemaking, accepts comments from the public, and then finalizes rules for announcement. The EPA issued final rules for Effluent Limitations Guidelines (ELG) in 2015 (regulates water discharge)

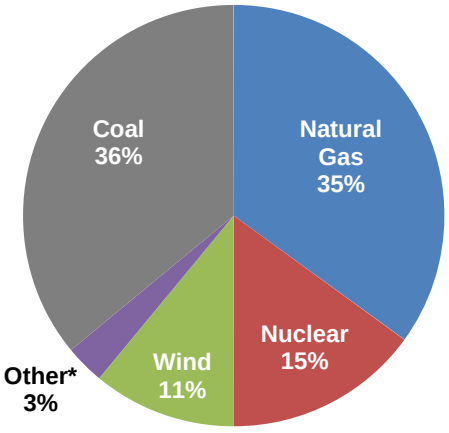
and Coal Combustion Residuals (CCR) in 2015 (regulates coal ash ponds) that were more stringent than first proposed. The Clean Power Plan (CPP), which regulates carbon dioxide emissions, would also impact the ability to cost-effectively operate coal-fired generation if it moves forward and is also more stringent than first proposed.

Each new regulation increases the cost of operating existing coal-fired plants over the 20-year horizon. Investment in Vectren's existing coal-fired generation to achieve compliance with ELG regulations would be significant. As currently written, ELG compliance would require investments by 2023.

ii. Low Gas Prices

The cost of fuel used by generation facilities to produce electricity is also accounted for in evaluating the cost of various electric supply alternatives. Gas prices are low and projected to be stable over the long term. Shale gas has revolutionized the industry, driving these low gas prices, and is fueling a surge in low-cost gas generation around the country. Vectren's IRP reflects the benefit low gas prices provide to gas-fired generation.

Projected 2030 MISO Energy Mix



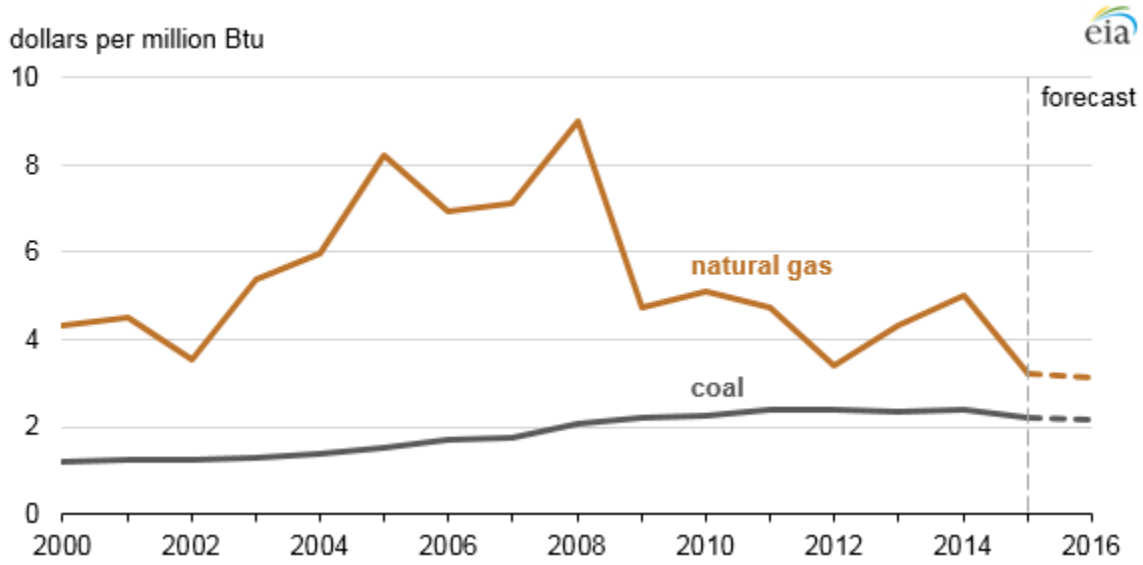
*Other includes hydro, pumped hydro, oil, solar, and others.

Vectren is a member of MISO, an independent transmission operator, which functions as the regional transmission operator for 15 Midwestern and Southern states, including Indiana (also parts of Canada). Within the MISO footprint, energy from gas generation has increased from 17% of total electric generation in 2014 to 28% in 2016. Energy from gas generation is projected to grow to 35% by 2030[3].

[3] MISO, 2016 Winter Readiness Workshop, presented on October 31st 2016, https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20

While the cost advantage of natural gas makes switching to natural gas-fired generation appear to be preferable from a cost perspective, Vectren also factored in the risk of particular supply side resources to its IRP. Reliance on an all natural gas generation portfolio would eliminate any resources that could mitigate the impacts of high gas prices or environmental regulations impacting natural gas facilities that might occur in the future. Vectren's risk modeling identified the risks with an unbalanced portfolio.

The table below shows average gas and coal fuel receipt costs at electric generating units between 2000 and 2016[4]. Note that shale gas has driven low gas costs since 2009.



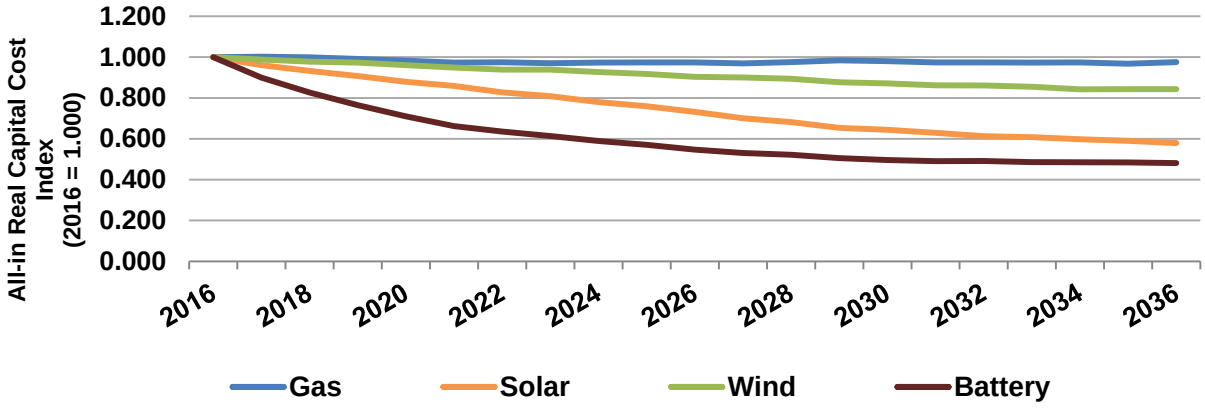
iii. Cost of Renewables

Another factor in Vectren's resource evaluation is the timing of the reduction in renewable energy costs. Vectren must either invest in its coal-fired generation to comply with ELG requirements, as currently written, or construct replacement generation by 2023. Renewable costs continue to decline, but they are still expected to

Special%20Meetings/2016/20161031%20Winter%20Readiness%20Workshop/20161031%20Winter%20Readiness%20Workshop%20Presentation.pdf, Slide 64

[4] U.S. Energy Information Administration, *Electric Power Monthly*, and *Short-Term Energy Outlook* (March 2016); http://www.eia.gov/todayinenergy/detail.cfm?id=25392

be more expensive in the Midwest region than other alternatives in the next several years. Vectren needs to learn more about integrating solar resources in its territory, but the price decline and cost effectiveness of large renewable investments does not support a larger investment by Vectren based upon the timing for resource decisions. Advancements in technology should drive renewable and battery storage costs down over the next several years, making them more competitive with other generation resources. Pace Global, an industry expert consultant, helped develop cost curves based on industry projections as well as their expert judgment. The cost curves below were included in Vectren's IRP analysis.



C. Uncertainty/Risk

The future is far from certain. Uncertainty creates a risk that a generation portfolio that was reasonable under an anticipated future fails to perform as expected if the future turns out differently. Vectren's integrated resource plan 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. To help better understand the wide range of possibilities for regulations, technology 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 varying resource mixes.

IV. Analysis

Having identified its need for electricity and the potential resources to satisfy that need, Vectren conducted an analysis to identify a 20-year preferred resource plan. Vectren's 2016 IRP analysis was more robust than ever before. A methodical, step-by-step analysis was used to determine the preferred portfolio. Analysis steps are listed below.

1) Determined objectives in developing a preferred resource plan, including:
   a) Maintain reliability
   b) Minimize cost to customers
   c) Mitigate risk to customers and Vectren
   d) Provide environmentally acceptable power leading to a lower carbon future
   e) Include a balanced mix of energy resources
2) Worked with consultants and IRP stakeholders to anticipate future uncertainties and incorporate them into several possible future states of the world. The future could bring economic development, economic stagnation, increased pace of technological development, more regulations, or fewer regulations. Multiple possibilities were explored.
3) Utilized computer modeling to consider various resource combinations to meet customer energy needs in each of these possible futures. The model is a deterministic, optimization model. It considered thousands of possible resource combinations to satisfy customer demand and energy needs for each pre-determined future. The model optimizes on cost to the customer. Seven portfolios were created; one for each pre-determined future. While creating these computer-generated resource portfolios are an important step in resource planning, it is also important to use judgment to consider other possibilities in creating portfolios with a balanced mix of resources to meet customer energy needs.
4) Worked with external stakeholders that participated in Vectren's IRP public stakeholder meetings to develop two balanced portfolios. Vectren also worked with expert consultants to develop five additional balanced portfolios. Additionally, Vectren included a portfolio very similar to the current mix of resources, which is

heavily reliant on the five existing coal units. In all, 15 portfolios were created for analysis.

5) Utilized probabilistic modeling to simulate operating each of the 15 portfolios under 200 possible computer-generated futures. The model captured portfolio performance to determine likely portfolio operating costs, emissions of carbon dioxide and regulated pollutants, exposure to the energy markets, risk, etc. In essence, this resulted in 3,000 model runs.
6) Used a balanced scorecard approach to evaluate the potential impact of multiple risk factors on each portfolio, including but not limited to, customer cost, environmental impact, flexibility, balance of resources, and economic impact to the communities that Vectren serves. No single portfolio performed best in all categories; however, the preferred portfolio performed well in all measured risk contingencies.

V. Stakeholder Process

Vectren believes in the importance of stakeholder engagement. Vectren's objectives for stakeholder engagement are as follows:

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

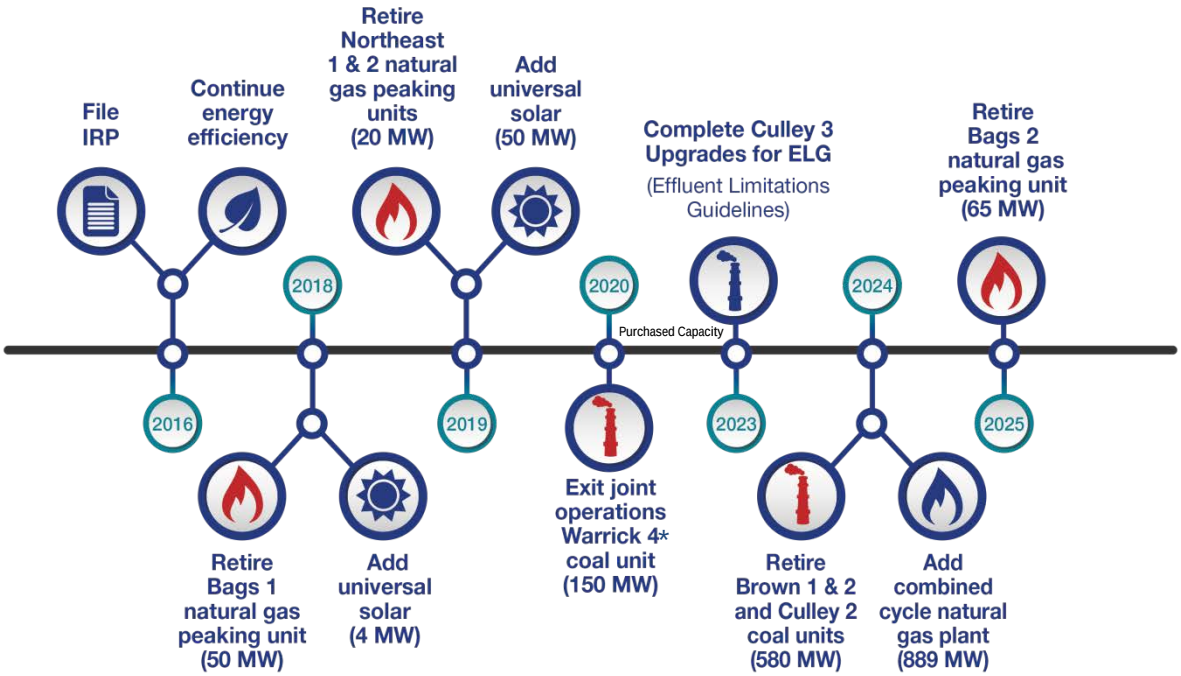
Vectren worked hard to have an open forum for stakeholders to voice questions/concerns and make suggestions on the IRP analysis. Each Vectren stakeholder meeting was opened by Carl Chapman, Chairman, President, and Chief Executive Officer of Vectren. He and other senior management, Vectren subject matter experts, and expert consultants actively participated in each meeting to help address stakeholder questions/concerns. Additionally, Vectren addressed stakeholder questions outside of public meetings via irp@vectren.com in a timely manner.

On February 3, 2016 Vectren participated in the Joint Utilities Stakeholder Education Session with other Indiana investor-owned utilities. After that, Vectren hosted three public stakeholder meetings at its headquarters in Evansville, IN. Dates and topics covered are listed below:

- April 7, 2016 – Vectren Public IRP Stakeholder Meeting
  - Vectren IRP Process Overview
  - Gathered Stakeholder Input on Uncertainties
  - Long-term Energy and Demand Forecast
  - Customer-Owned Distributed Generation
  - 2016 IRP Technology Assessment Generation Resource Alternatives
  - Generation Retrofit Alternatives
  - Energy Efficiency Modeling Discussion
- July 22, 2016 – Vectren Public IRP Stakeholder Meeting
  - Environmental Compliance
  - Base Case/Modeling Inputs
  - Resource Screening Analysis and Optimization Modeling
  - Scenario Development
  - Gathered Stakeholder Input to Portfolio Selection
- November 29, 2016 – Vectren Public IRP Stakeholder Meeting
  - Recap of Vectren IRP analysis
  - Presentation of the Preferred Portfolio
  - Existing EPA Regulations
  - Optimization Modeling Results and Portfolio Development
  - Risk Analysis Results

In addition to these public meetings, Vectren met with the Vectren Oversight Board and staff from the Indiana Utility Regulatory Commission to discuss energy efficiency modeling for the 2016 IRP on October 14, 2016. All Vectren stakeholders were invited to participate via webinar.

VI. The Preferred Portfolio



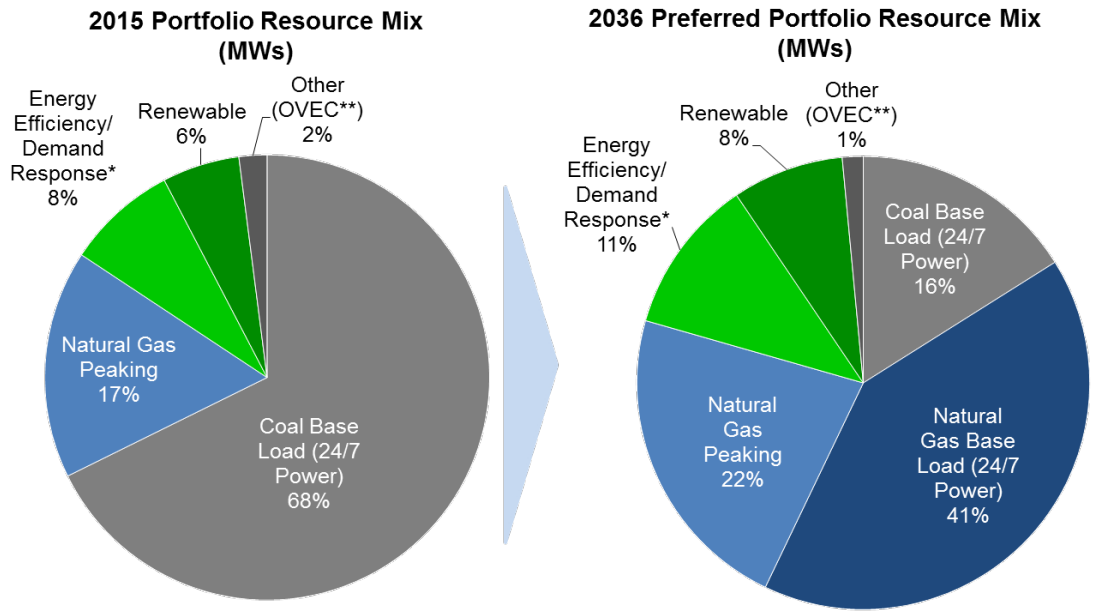
*Warrick 4 jointly owned with Alcoa, which is in the midst of transition. Vectren continues to discuss the future of Warrick 4 with Alcoa.

Based on the analysis Vectren conducted, Vectren has identified a preferred portfolio that consists of continued energy efficiency, retirement of existing coal and some gas units (Bags Units 1 and 2, Brown Units 1 and 2, FB Culley Unit 2, and Northeast Units 1 and 2), exiting joint operations of Warrick Unit 4, and construction of a combined cycle natural gas plant and solar generation. This preferred portfolio:

- Is among the best performing portfolios across multiple measures on the balanced scorecard.
- Is among the lower cost portfolios (within 4% of the lowest cost portfolio).
- Leads to a lower carbon future – Achieves almost 50% reduction in carbon (base year 2012) by 2024, which exceeds the Clean Power Plan (CPP) requirements – carbon emissions reduction from 2005 levels would be almost 60%.
- Brings renewables into the portfolio by 2019. Renewables and ongoing Energy Efficiency account for approximately 20% of total capacity by 2036.

- Provides low-cost peaking generation through duct-firing[5] that enhances opportunities for economic development and wholesale sales, which lowers customer bills.
- Avoids reliance on a single fuel and provides a balanced mix of coal, gas, and renewables. While reliance on gas is significant, a duct-fired plant would allow for back up of further variable renewable resources in the long term.
- Is among the best portfolios in terms of limiting negative economic impact from job loss and local tax base. University of Evansville professors concluded that the economic ripple effect of losing 82 FB Culley jobs equates to 189 additional job losses in the community. Total state and local tax impact would be approximately 7 million dollars annually. Moreover, to the extent a new gas unit is built at the AB Brown site, over 100 total jobs are expected to be retained in the community. Total state and local tax impact would be approximately 4 million dollars annually.
- Reduces dependence on coal-fired generation over time and provides flexibility to adapt to changes in technology.
- Takes advantage of tax incentives for solar power plants.

[5] Depending on set up, Duct-firing can provide approximately 200 MWs (Installed Capacity) of efficient peaking capacity capability through gas burners located within the heat recovery steam generator. These burners can be fired to generate more power when needed.



*Cumulative Demand Response & Net Energy Efficiency
**Vectren's 1.5% ownership of Ohio Valley Electric Corporation (OVEC) coal units. Per contractual obligations, all portfolios include OVEC.

VII. Next Steps

The preferred portfolio calls for Vectren to make changes to its generation fleet. Some of these changes require action in the near term. First, the IRP calls for continuation of energy efficiency. Vectren's current authority related to energy efficiency initiatives expires on December 31, 2017. Vectren will file for authority necessary to facilitate continuation of energy efficiency early in 2017 so that programs continue to be available. Second, Vectren must comply with ELG requirements, as currently written, by the end of 2023. As such, Vectren plans plant upgrades for FB Culley 3 for conversion of dry bottom ash and flue gas desulfurization waste treatment. The preferred portfolio calls for construction of a new combined cycle gas turbine in lieu of further investments in Brown Units 1 and 2, FB Culley Unit 2, and Warrick Unit 4 to ensure compliance. IURC approvals will need to be sought in the near future. Third, Vectren intends to pursue solar projects in 2017 and 2019. 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, and other assumptions could warrant deviations from the preferred plan.

Following the outcome of the recent presidential election, there is potential for industry change over the next several years. For example, the EPA's Clean Power Plan may be rescinded or modified. Additionally, Clean-Energy Tax incentives may be at risk. Even in the midst of possible industry change, other rules like ELG/CCR, which are the main drivers of closing Vectren coal plants, will be much more difficult to change.

Vectren is confident in the need for new gas generation in 2024. Under all scenario modeling, a natural gas-fired plant was selected, including the low regulatory scenario. While future carbon regulations are less certain than prior to the election, it is likely that new administrations will continue to pursue a long term lower carbon future. Vectren's preferred portfolio positions the company to meet that expectation.

Other aspects of the preferred portfolio are less certain. For example, the timing of exiting joint operations of the Warrick 4 coal plant could change. The plant is jointly owned with Alcoa, which recently went through a corporate reorganization and remains in the midst of transition. Given the plant, absent incremental investment, does not comply with the CCR and ELG requirement, Vectren continues to talk to Alcoa about the timing of possible closure. Additionally, Vectren plans to add 50 MW of solar in 2019, which corresponds with clean energy tax incentives. Timing of this solar plant may change should these incentives not be available.

SECTION 1
OVERVIEW

1.1 COMPANY BACKGROUND

Vectren Corporation is an energy holding company headquartered in Evansville, Indiana. Vectren's wholly owned subsidiary, Vectren Utility Holdings, Inc. (VUHI), is the parent company for three operating utilities: Indiana Gas Company, Inc. (Vectren North), Southern Indiana Gas and Electric Company (Vectren), and Vectren Energy Delivery of Ohio (VEDO).

Vectren North provides energy delivery services to more than 570,000 natural gas customers located in Central and Southern Indiana. Vectren provides energy delivery services to over 144,000 electric customers and approximately 110,000 gas customers located near Evansville in Southwestern Indiana. VEDO provides energy delivery services to approximately 312,000 natural gas customers near Dayton in West Central Ohio.

1.2 INTEGRATED RESOURCE PLANNING

Vectren takes integrated resource planning very seriously. Vectren is required to submit its Integrated Resource Plan (IRP) to the Indiana Utility Regulatory Commission (IURC) every two years (moving to a three year cycle). The IRP begins with a forecast of customer electric needs over a 20-year period and is used as a guide for how Vectren will serve existing and future customers 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.

The future is uncertain. Several factors have helped to set the stage for this analysis. Environmental Protection Agency (EPA) regulations are putting great pressure on coal resources. Several regulations that were recently finalized are more stringent than originally proposed. Gas prices are low and projected to be stable over the long term.

Shale gas has revolutionized the industry, driving these low gas prices. This has fueled a surge in gas generation investment.

Renewable costs continue to decline, but they are still expected to be more expensive in the Midwest region than other alternatives in the next several years. Vectren will continue to monitor developments related to the high voltage transmission lines still needed to both increase the availability and reduce the cost of wind. Additionally, Vectren will continue to observe developments in Midcontinent Independent System Operator (MISO), Vectren's regional transmission operator. Within Vectren's zone, MISO is projecting a shortfall in generation and demand side options needed to maintain reliability beginning in 2018 for high certainty resources[6]. The shortfall continues to grow through 2021. Regardless of the final plan, reliability needs to be maintained, and customer costs must be a priority.

1.2.1 IRP Objectives

Vectren's IRP objectives are based on the need for a resource strategy that provides value to its customers, communities, and shareholders. Vectren'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[7] of supply and demand resources to best meet customers' needs for reliable, reasonably priced, environmentally acceptable power over a wide range of future market and regulatory conditions taking into account risk and uncertainty. Specifically, Vectren's objectives are as follows:

- Maintain reliability
- Minimize rate/cost to customers
- Mitigate risk to Vectren customers and shareholders
- Provide environmentally acceptable power leading to a lower carbon future

[6] High certainty resources are existing resources that have a "High" confidence of being available in the planning year, as determined by utilities in the Organization of MISO States (OMS) survey.
[7] A portfolio is a mix of future supply and demand side resources to meet expected future demand for electricity.

- Include a balanced mix of energy resources
- Minimize negative economic impact to the communities that Vectren serves

1.2.2 IRP Development

Since conducting the 2014 IRP, Vectren has worked diligently to incorporate stakeholder input (direct comments about the 2014 IRP, including the director's report, and indirect comments through suggestions to other utilities) into the 2016 analysis. As a result, the 2016 IRP is much more robust than any Vectren IRP before it.

Vectren made the following commitments, which are incorporated into this IRP analysis:

- construct scenarios (possible future states), which include coordinated data inputs with a well-reasoned narrative,
- conduct a probabilistic risk analysis to explore the outer bounds of probability,
- model future energy company sponsored energy efficiency as a resource (not built into the load forecast),
- evaluate if retirement makes sense for any of Vectren's existing coal generating units within the 20 year time frame under each scenario,
- monitor Combined Heat and Power (CHP) developments and include CHP as a resource option,
- consider conversion or repower of coal units to gas,
- fully consider renewable options, and
- update the IRP document format to be more readable.

Vectren worked closely with industry experts to develop a comprehensive analysis. Pace Global helped with scenario development, modeling inputs, and a comprehensive risk analysis, which included probabilistic modeling. Burns and McDonnell developed a technology assessment which provides resource costs for various types of generation technologies, such as gas, solar, wind, storage, etc. It can be found in Technical Appendix Confidential Attachment 1.2 2016 Vectren Technology Assessment Summary Table. Vectren also engaged Burns and McDonnell in developing a site selection

analysis to better understand the ideal location for gas generation, should it be chosen in the preferred portfolio. Additionally, Burns and McDonnell conducted a portfolio screening analysis to help determine the preferred portfolio. Itron developed the base sales and demand forecast, which included a forecast of customer owned solar generation.

1.3 CHANGES THAT HAVE OCCURRED SINCE THE LAST IRP

Several developments have occurred since the last IRP was submitted in 2014, which helps to illustrate the dynamic nature of integrated resource planning. The IRP analysis and subsequent write up represent the best available information for a point in time. The following sections discuss some of the major changes that have occurred over the last two years. The robust risk analysis recognizes that conditions will change. Changes over the last few years provided Vectren with valuable insight on how modeled scenario outcomes can change over time.

1.3.1 Environmental Rules

1.3.1.1 Air

There have been a number of changes in air regulations since the 2014 IRP. The Mercury and Air Toxics Standard (MATS) was published in the Federal Register in February 2012. The rule sets plant-wide emission limits for the following hazardous air pollutants (HAPs): mercury, non-mercury HAPs (e.g. arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride)[8]. Compliance with the new limits was required by April 16, 2015. At the time of the last IRP, Vectren was awaiting approval by the Commission for its MATS Compliance plan (IURC Cause 44446) which included organosulfide injection at the base load units (AB Brown 1, AB Brown 2, FB Culley 3, and Warrick 4). All equipment

[8] MATS Limits: The EPA established stringent plant-wide mercury emission limits (1.2 lb/TBtu for individual unit or 1.0 lb/TBtu for plant average) and set surrogate limits for non-mercury HAPs (total particulate matter limit of .03 lb/MMBtu) and acid gases (HCL limit of .002 lb/MMBtu). The surrogate limits can be used instead of individual limits for each HAP.

has been approved and installed, and Vectren's units are currently in compliance with MATS limits.

In March 2015, EPA entered into a Consent Decree[9] with environmental stakeholders to resolve litigation concerning deadlines for completing 1-hour sulfur dioxide (SO_2) National Ambient Air Quality Standard (NAAQS) designations. EPA identified five sources in Indiana that exceeded a set threshold for SO_2, including the AB Brown plant. In order to ensure that Posey County continued to meet the attainment designation for the new one hour standard, Vectren voluntarily agreed to lower its emission rate for SO_2 at its AB Brown plant. Vectren requested a Commissioner's Order to voluntarily accept a lower SO_2 emission limit that went into effect April 19, 2016. The state will continue to review modeling for additional counties including Warrick County and the FB Culley and Warrick power plants located within that county. A preliminary review indicates that Warrick County is in compliance without additional reductions.

In December 2015, Vectren agreed to a modified Consent Decree to resolve alleged air violations at the FB Culley and AB Brown plants. Based on the negotiated settlement, Vectren eliminated the bypass stack for FB Culley Unit 2 and installed equipment to mitigate incremental sulfur trioxide (SO_3) emissions from the selective catalytic reduction technology installed on AB Brown Units 1 and 2 and FB Culley Unit 3 to control nitrogen oxides (NOx). Each unit is required to maintain a sulfuric acid (H_2SO_4) emission limit to demonstrate compliance.

EPA finalized the Clean Power Plan (CPP) that established carbon dioxide (CO_2) emission standards for a state's electric generating fleet in August 2015. States were given the discretion to set unit specific limits or adopt a mass-based or rate-based allowance trading program. The US Supreme Court issued a stay of the rule, which will remain in place through ultimate Supreme Court review of the opinion of the lower court.

[9] The Consent Decree required EPA to designate as nonattainment, attainment, or unclassifiable certain areas that included sources that emitted more than 16,000 tons of SO_2 in 2012 or emitted more than 2,600 tons of SO_2 with an average emission rate greater than 0.45 lbs/MMBtu.

It is not anticipated that final order on judicial review will come until late 2017 at the earliest. In the event that the CPP is upheld, the state of Indiana will likely develop a State Implementation Plan (SIP). For this analysis, Vectren assumed a two year delay with compliance beginning in 2024.

In addition to the above regulations, on September 7, 2016, EPA finalized the Cross State Air Pollution Rule (CSAPR) Update Rule which established lower ozone season Nitrous Oxide (NOx) allowances for each unit to incorporate the revised Ozone NAAQS. The new limits take effect with the ozone season beginning in May 2017.

1.3.1.2 Water

On September 30, 2015, EPA published the final Effluent Limitations Guidelines rule (ELG). The rule sets strict technology based limits for waste water generated from fossil fuel fired generating facilities and in particular, will force significant operational and technological changes at coal-fired power plants. In the draft proposal, EPA listed eight possible options, with four identified as "preferred." Within the group of preferred options were exemptions for smaller scrubbers and generating units that could have exempted Vectren's units from certain requirements. However, in the final regulation EPA chose to bypass the preferred options and went with a hybrid of the most stringent options for fly ash transport water, bottom ash transport water, and flue-gas desulfurization (FGD) waste water.

While the final rule includes reference to multiple waste waters, the key elements applicable to Vectren are FGD waste water and ash transport water. Specifically, FGD waste water must meet new limits for arsenic, mercury, selenium, and nitrate at the end of the wastewater treatment system and prior to mixing with any other process water. 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. The applicability date for the new requirements shall be as soon as possible after November 1, 2018 but no later than December 31, 2023 and established in a

schedule outlined in National Pollutant Discharge Elimination System (NPDES) permit renewals. For FGD waste water, alternate, but more restrictive limits can be voluntarily agreed to which would automatically extend the applicability date to December 31, 2023. Technology to meet the more restrictive limits could include the installation of zero liquid discharge equipment that would eliminate all discharge of FGD waste water.

1.3.1.3 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 regulatory deadlines that could trigger the closure of surface impoundments include non-compliance with safety factor assessment standards (April 2017), exceedance of ground water protection standards (April 2018), or failure to demonstrate compliance with location restrictions (April 2019).

1.3.1.4 Post-election Regulations Update

President-elect Trump has indicated that he intends to review environmental regulations. However, at this time it is unclear which regulations President-elect Trump's new EPA administrator intends to review, other than the Clean Power Plan and the Waters of the US rule. In order to rescind and/or modify a final regulation such as the CPP, or the CCR and ELG rules, the new administration would be required to go through a new notice and comment rulemaking process, which could require 18 months to 2 years to complete, and in the case of health and / or technology based standards such as the ELG rule would require a defensible rationale.

With respect to the issue of carbon regulations, President-elect Trump could withdraw from the non-binding Paris carbon reduction goals. However, as indicated above, the

CPP is a final regulation, so it must be rescinded/modified through a supplemental notice and comment rulemaking. Additionally, the previous Endangerment Finding would also need to be rescinded and/or modified. It should also be noted the new Department of Justice may choose to no longer defend the rule; however, the rule would still be defended by some states and environmental groups. While these options are possible, all would require some time. The IRP is a long-term resource plan; future administrations will likely pursue a lower carbon future.

Even if the Trump administration successfully delays/rescinds the CPP, Vectren's decision on continuing operation of its coal-fired fleet is more heavily influenced by the CCR and ELG rules, the primary driver of near-term environmental compliance expenditures modeled in the IRP. These rules require notice and comment rulemaking to rescind and/or modify, which is an 18-24 month process. Rules such as the ELG rule are technology mandates arising under legislation, in this case the Clean Water Act, and are more difficult to set aside. They must be supported by a technological or human health rationale.

1.3.2 Environmental Upgrades for MATS

To comply with the Mercury and Air Toxics Standard (MATS), Vectren installed equipment to inject an organo-sulfide solution into the scrubbers at AB Brown Units 1 and 2, FB Culley combined stack for Units 2 and 3, and Warrick Unit 4. In addition to the treatment technology, MATS also required the installation of new monitoring equipment on the stacks for each of the listed units to assess compliance with the new limits. Continuous emissions monitoring system (CEMS) was installed to monitor filterable particulate (as a surrogate for non-mercury HAPS metals), a separate CEMS to monitor hydrogen chloride, and sorbent traps to measure mercury.

1.3.3 Legislation and IRP Rule Making Process

The Demand Side Management ("DSM") landscape in Indiana has undergone significant changes in recent years, beginning in 2014 with the enactment of Senate

Enrolled Act 340 ("SEA 340"). This not only allowed certain large Commercial & Industrial (C&I) customers to opt-out of participation in Company sponsored energy efficiency ("EE") programs, but also eliminated the savings targets for jurisdictional electric utilities established by the Commission in Cause No. 42396 ("Phase II Order").

Since then, Senate Enrolled Act 412 ("SEA 412") was codified at Ind. Code § 8-1-8.5-10 ("Section 10"), and further impacts how utilities plan for and implement EE programs in Indiana. Beginning not later than calendar year 2017, an electricity supplier, which includes Vectren, is required to petition the Commission at least one time every three years for approval of a plan that includes: (1) energy efficiency goals; (2) energy efficiency programs to achieve the energy efficiency goals; (3) program budgets and program costs; and (4) evaluation, measurement, and verification ("EM&V") procedures that must include independent EM&V (the "Plan").

Once a Plan has been submitted for approval, the Commission must consider the ten factors outlined in Section 10 when determining the overall reasonableness of the Plan. One of the factors that must be considered in this determination is whether the Plan is consistent with the electricity supplier's most recent long range IRP submitted to the Commission. Section 10 requires the Commission to approve an electricity supplier's Plan if, after notice, hearing, and consideration of the ten factors outlined in Section 10, the Commission determines the plan to be reasonable.

Besides the enactment of Section 10, another regulatory development is the pending rulemaking currently underway, known as IURC RM #15-06 that continues to refine the IURC's IRP rules. This is essentially a continuation of the rulemaking from IURC RM #11-07 that resulted in a draft rule dated October 4, 2012, which was never finalized and adopted by the Commission. However, Vectren and other utilities began voluntarily following the 2012 [IRP] draft rule in 2013 and 2014, which outlines the requirements for the IRP process and the IRP report. In crafting the proposed rule, the Commission began with the 2012 draft rule and accepted comments and edits to that draft rule. One

significant change from the 2012 draft rule to the proposed rule is the switch from a two year filing requirement to a three year filing requirement, which matches the three year EE Plan filing requirement set forth in Section 10. Vectren continues to actively participate in the rulemaking process and will be prepared to follow the rule once it is finalized and adopted by the Commission. Note that Vectren followed the 2012 draft rule for the 2016 IRP.

1.3.4 Alcoa

In January of this year, Alcoa announced it would permanently cease production of its Warrick Operation smelter in the 1st quarter. Alcoa also communicated that the on-site rolling mill and power plant will continue to operate.

The Warrick power plant consists of four generating units: three 150 Megawatt (MW) industrial units wholly owned by Alcoa and one 300 MW electric generating unit (Warrick 4) that is jointly owned by 50% Alcoa and 50% Vectren. Prior to the smelter closing, the Alcoa power plant provided most of its 600 MW electric generation, if not all, to meet the electric demand of the Warrick Operations facility with the smelter being the majority of that demand. With the smelter closing on March 24, 2016, the electric demand for the Warrick Operations facility is dramatically less. Alcoa has recently split into two (2) separate public companies. Given these operational and organizational changes, Alcoa's interest in continuing to operate the jointly owned Warrick 4 300 MW electric generating unit is unclear.

1.3.5 Co-generation (Combined Heat and Power)

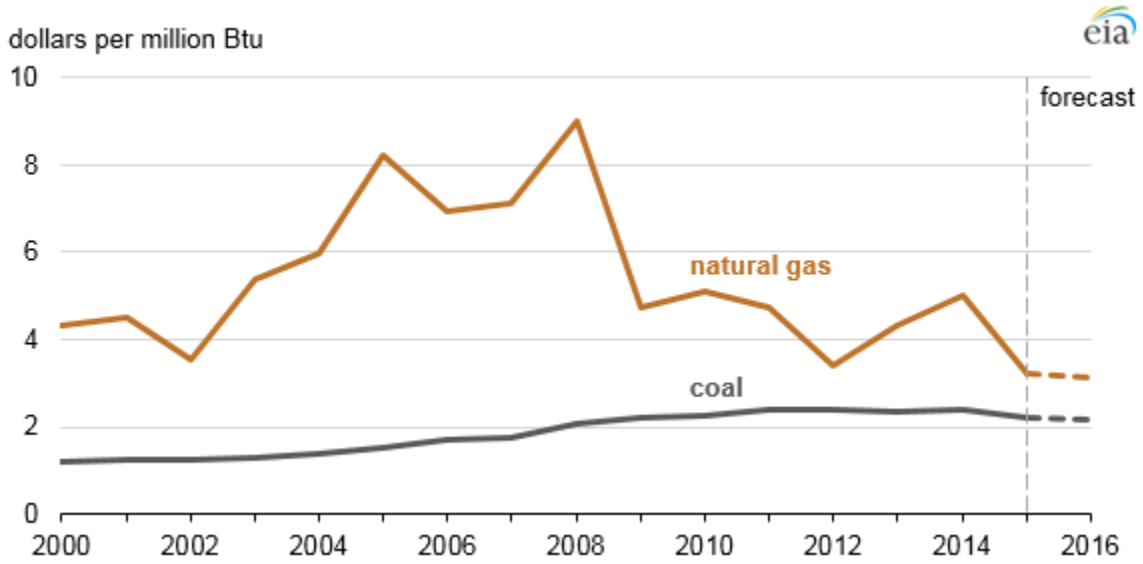
A large industrial customer has installed a natural gas fired co-generation unit that is expected to come on-line by January 2017. The co-generation unit is expected to cover the majority of this customer's load, and Vectren will cover the balance with firm service. The co-generation unit will produce steam and electricity for production processes. This development is reflected in the sales and demand forecast for the IRP.

1.3.6 Increasing Use of Gas-Fired Generation, Regionally and Nationally

There has been a surge of natural gas generation in the United States over the last several years. According to the EIA, electricity net generation from natural gas in the US has increased from approximately 14% in 2000 to approximately 32% in 2015[10]. This has been driven by three primary factors 1) low gas prices, 2) age of existing coal fired generation, and 3) stricter environmental requirements imposed on coal fired generation.

Gas prices are low and projected to remain stable over the long term. Shale gas has revolutionized the industry, driving gas prices down to historically low levels as the supply of natural gas has grown. In recent years, natural gas generation has been competitive with coal generation and therefore has frequently been economically dispatched in place of coal. The table below shows average gas and coal fuel receipt costs at electric generating units between 2000 and 2016[11].

Figure 1.1 – Average Fuel Receipt Costs at Electric Generating Plants (2000-2016)



[10] US Energy Information Administration; August 2016 Monthly Energy Review, Table 7.2b Electricity Net Generation: Electric Power Sector; http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf
[11] U.S. Energy Information Administration, *Electric Power Monthly*, and *Short-Term Energy Outlook* (March 2016); http://www.eia.gov/todayinenergy/detail.cfm?id=25392

Coal has been a long standing fuel for electric generation in the US, as a result a substantial portion of the existing coal fleet is reaching the age when wear and tear, and equipment obsolescence has made their continued operation uneconomic in the long run. Consequently a very sizeable portion of the US coal fleet has, or is expected, to retire due to old age.

In addition, as mentioned in Section 1.3.1, numerous environmental rules have been recently finalized by the EPA, including MATS, ELG, CCR, and CPP. Collectively these rules have helped to retire coal plants across the country, with more closures to come through the early 2020s due to associated compliance costs. Additionally, some politicians and environmental advocacy groups have worked hard to negatively shape public perception of coal fired power plants. Government support for renewables in the form of tax incentives and renewables portfolio standards have also helped to displace coal generation in the market.

1.3.7 MISO

MISO requires Vectren and other member electric utilities to maintain a Planning Reserve Margin (PRM). The PRM is designed to ensure there is enough power capacity throughout the MISO region to meet customer demands during peak periods, including peak periods where some equipment might fail. In recent years, the Planning Reserve Margin (PRM) throughout MISO has dwindled. Because there is less availability of capacity, the price for capacity available in MISO's annual auction has been volatile. The Organization of MISO States (OMS), of which the IURC is a participant, and MISO teamed together 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 served as the main vehicle in communicating to the MISO stakeholder community the anticipated PRM for upcoming years and serves as a tool in determining whether additional action is needed.

Since its inaugural survey, MISO has warned that there may be inadequate capacity within the MISO footprint at some future date. 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. The table below illustrates the year-to-year volatility in the survey results and the uncertainty that exists.

Figure 1.2 – OMS-MISO Resource Adequacy Survey Results

OMS-MISO Resource Adequacy Survey Results by Year	Zone 6 Resource Adequacy Shortfall, Earliest Projection	MISO-wide Resource Adequacy Shortfall, Earliest Projection
2014	1.2 GW shortfall in 2016	2.0 GW shortfall in 2016
2015	400 MW shortfall in 2016	1.8 GW shortfall in 2018
2016	800 MW shortfall in 2018	400 MW shortfall in 2018

The projected capacity shortfalls have contributed to 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[12], as shown in the table below. These large swings in prices have made it difficult to forecast forward years.

[12] SNL Financial – Market Prices – ISO Capacity Summary – MISO

Figure 1.3 – MISO Zone 6 Capacity Price History

Planning Year	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/day[13]	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/year	Year-over-Year Price Change
2013-2014	$1.05	$383.25	-
2014-2015	$16.75	$6,113.75	1495% Increase
2015-2016	$3.48	$1,270.20	79% Decrease
2016-2017	$72.00	$26,280.00	1969% Increase

MISO has stated that its role in resource planning is to provide data transparency, markets signals, and assist its stakeholders throughout the resource planning process. To improve its market signals, MISO is currently working on several reforms to its capacity construct. Additionally, in order to ensure data transparency and assist its stakeholders in resource planning, MISO is working with the OMS to refine the results from the survey and continue improving the accuracy and metrics in which the PRM is measured. For more information on MISO, please read Section 4.7, PLANNING RESERVE MARGIN DISCUSSION.

1.3.8 Solar Generation

The Energy Policy Act of 2005 created a 30 percent ITC for residential and commercial solar energy systems placed in service between January 1, 2006 and December 31, 2007. The in service date has been extended several times since then, most recently in 2015 in the Omnibus Appropriations Act (P.L. 114-113). Additionally, the language was updated from “in service” to “commence construction” for projects completed by the end of 2023. 2019 is the last year to commence construction and receive the full 30% benefit (it tapers down from there).

Renewable costs, particularly solar, continue to decline helping to drive demand for more solar energy production. Even with the extension of the ITC, solar panel energy in

[13] 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).

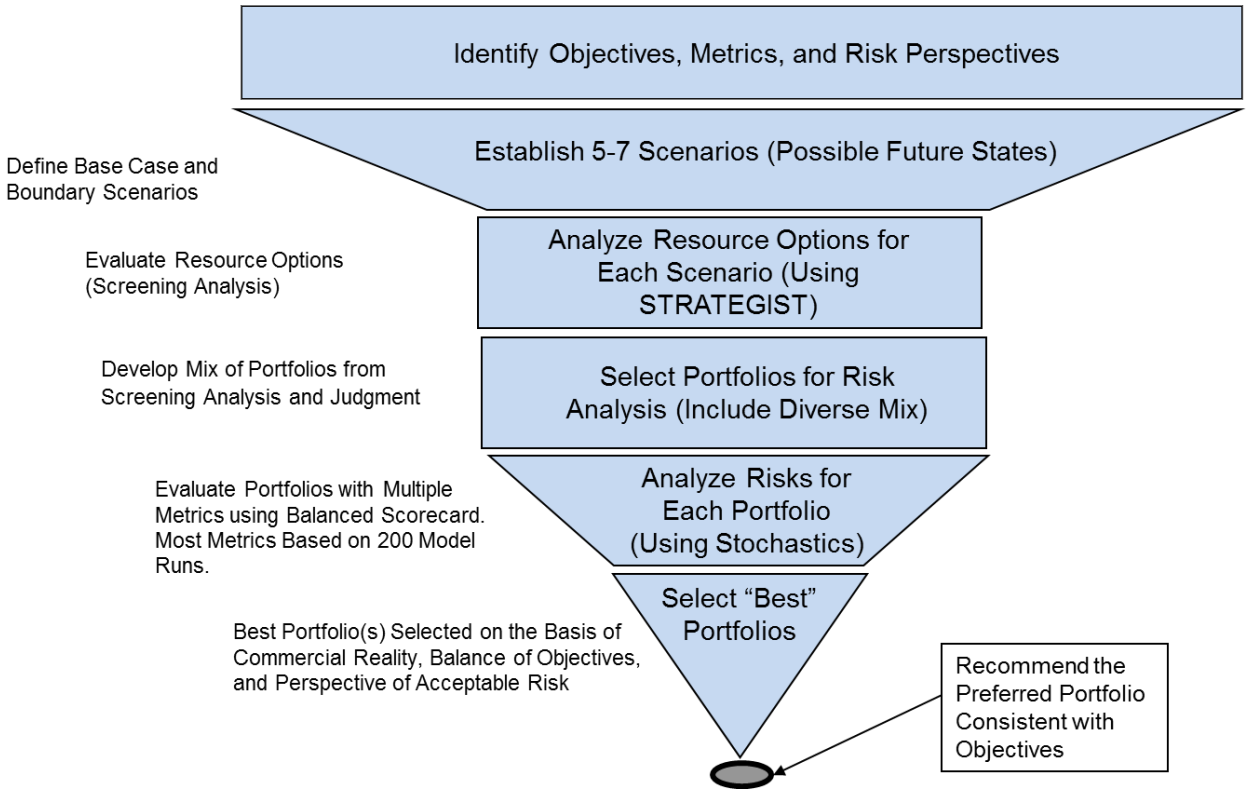
the Midwest is still expected to be more expensive than other alternatives in the next several years. In 2015, solar energy accounted for 1% of total generation in the U.S.

SECTION 2
VECTREN'S IRP PROCESS

2.1 VECTREN'S IRP PROCESS

Vectren's 2016 IRP followed a very structured, comprehensive process over a 15 month period with extensive economic, technical, and risk analyses. This process was designed to ensure that all relevant technologies were screened and evaluated, and the resulting portfolio combinations were subjected to a wide range of future market and regulatory conditions to ensure that the recommended portfolio would best meet its objectives under uncertainty. The process followed is illustrated below.

Figure 2.1 – Vectren IRP Process



The process used to select the recommended portfolio is outlined below:

- Section 2.2 describes how multiple objectives were tracked and measured. These metrics were the key to evaluating how portfolios were judged against each other in the final selection of the best portfolio.

- Section 2.3 describes how the scenarios were developed for screening technologies. Vectren selected six "boundary scenarios" around its consensus base case scenario to ensure that the portfolios selected perform reasonably well across a range of market and regulatory conditions.
- Section 2.4 describes the screening of technologies. Burns and McDonnell used the STRATEGIST model to assess how different technologies and groups of technologies performed across each of the base case and six additional scenarios to help Vectren define which portfolios it wanted to consider for its risk analysis.
- Section 2.5 describes the selection of a group of portfolios for risk analysis. Some of the portfolios came directly out of the screening analysis, considering which group of portfolios performed best under each set of market and regulatory conditions. Others were selected based on the judgment of Vectren and by stakeholders through its stakeholder process. Vectren wanted to ensure that there was due consideration to metrics besides least cost to capture more diverse portfolios, greater penetration of renewables, energy efficiency, and other considerations.
- Section 2.6 describes the input distributions for the risk analysis. This tracks the steps performed in the process, the selection of the distributions, and the use of AURORAxmp to provide carbon prices, power prices, and market retirements and construction of new generation. This section also describes the analysis of the portfolios against the 200 iterations of scenarios that were developed in the previous steps and how resulting metrics are evaluated.
- Section 2.7 describes the selection of the "best" portfolio and provides the basis for eliminating portfolios that do not perform well against target metrics and for selection of a portfolio that performed best.

Vectren evaluated and balanced the expected costs and risks of each portfolio, incorporating environmental goals, to select a portfolio with a good cost-risk combination. Throughout the process, Vectren sought and received input from

stakeholders through three public meetings meant to educate and engage all those with an interest in this IRP.

2.2 IDENTIFY OBJECTIVES, METRICS, AND RISK PERSPECTIVES

Vectren's IRP process is designed to assure a systematic and comprehensive planning process to determine the "recommended portfolio" that best meets all of 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 of the energy company and its customers.

In addition, the IRP process ensures that Vectren meets its environmental regulations and reliability requirements, while reducing its vulnerability to market and regulatory risks, the risk of supply disruptions, and increases the diversification of its supply sources, maintaining the flexibility to take advantage of renewable options and storage when the economic conditions favor it.

One component of resource planning is "least cost" planning, which identifies the portfolio or supply and demand resources that are most likely to result in the lowest expected cost to its customers. While this is certainly an important objective, it is by no means the only objective. Vectren has a number of important objectives, each of which needs to be considered when evaluating the best portfolio for its stakeholders over time. Vectren's IRP strategy is designed to accommodate the ongoing changes and uncertainties in the market. Vectren's IRP objectives are based on the need for a resource strategy that provides long term value to its customers, communities, and shareholders. Specifically, Vectren's IRP objectives are as follows:

- Provide all customers with a reliable supply of energy at the lowest reasonable cost.
- Develop a plan with the flexibility to adapt to market conditions, regulatory and technological change to minimize risk to Vectren customers and shareholders
- Provide environmentally acceptable power, leading to a lower carbon future

- Provide a predictable, balanced mix of energy resources designed to ensure costs do not vary greatly across alternative future market conditions or supply disruptions.
- Minimize the impact of Vectren's past, current, and future operations on the local economy.
- Provide high-quality, customer-oriented services which enhance customer value.

Each objective was given defined and measurable metrics. By testing alternative portfolios against these metrics, Vectren increases the likelihood that the portfolio it ultimately selects will be the best portfolio, in that it meets all of Vectren's objectives better than any other portfolio of assets across a broad range of possible futures. The following metrics were used to select the preferred portfolio:

Figure 2.2 – Vectren Risk Metrics

Objective	Metric
Customer Rate (or utility cost) Metric	• Net Present Value (NPV) of Revenue Requirements
Manage or Minimize Market Risks	• Standard Deviation of NPV Across 200 Future Conditions • Volume of Market Purchases • Volume of Capacity Purchases
Cost Risk-Tradeoff	• NPV against Standard Deviation
Balance and Flexibility	• Net Sales Position • Concentration on One Technology • Number of Technologies • New Remote Resources in Generation Mix
Environmental Requirements	• CO_2 Reductions from 2012 levels • SO_2 and NO_X Reductions from 2012-2015 levels
Local Economic Impacts	• Jobs and Local Economy

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 the lowest expected costs may not be the most stable (lowest band of risks), have the most carbon reductions, or provide the needed flexibility to adapt to changing conditions. The objective of the IRP is to find the right balance of these metrics across a wide variety of future conditions to ensure that the ultimate choice of a portfolio performs well, regardless of the circumstances.

A further description of each metric is provided below.

2.2.1 Rate/Cost Metric

2.2.1.1 Lowest Reasonable Customer Cost

The metric typically used for this objective is Net Present Value of Vectren's Revenue Requirements (NPVRR). The NPVRR is a measure of all costs (for each asset, the cost of generation – capital, O&M, fuel, and any ancillary costs, including transmission, plus 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.

2.2.2 Risk Metrics

2.2.2.1 Standard Deviation and the 95th Percentile of Revenue Requirements

In the risk analysis, an assessment of hundreds of scenarios of future market and regulatory conditions were performed on each portfolio. The NPVRR was calculated for each scenario (iteration) and then a frequency distribution of these NPVRRs was calculated. A "standard deviation" is a measure of the variability of the portfolio outcomes. By definition, by taking the mean or average value of the 200 iterations, and then adding and subtracting the value of one standard deviation to the mean value, one captures about 67% of the total observations. Adding or subtracting two standard deviations around the mean captures about 95% of the outcomes. The 95th percentile NPVRR typically represents a plausible worst case outcome of the distribution. Portfolios that have a great deal of uncertainty will have high costs in the worst case outcome. To minimize risk, one would select the portfolio with the lowest measure of dispersion or the lowest standard deviation around the mean value.

2.2.2.2 Market Risk – Reliance on Purchases from the Market

Dispatch modeling informs us of how often units in a given portfolio generate electricity to serve the needs of customers. The balance not met by Vectren's owned generation is supplied by the market. If Vectren relies too much on the market, it subjects Vectren's customers to market price volatility that Vectren would not experience using its own generation assets. Hence, Vectren can measure the percentage reliance on the market as one measure of risk of the portfolio.

2.2.2.3 Capacity Volume Risk

In the base or reference case, the model ensures that adequate capacity purchases are made to meet UCAP reserve margin requirements. When 200 iterations of the model are run, there are high load scenarios where additional capacity purchases may be required to continue to meet the target UCAP requirements. For each portfolio, Vectren calculated on average (across the 200 iterations) how many additional capacity purchases might be required. Since the capacity market is typically more volatile than the energy market, the cost associated with these purchases could be significant.

2.2.3 Environment Improvements Metric

2.2.3.1 Carbon Footprint Reductions from 2012 Levels

Each portfolio was designed to meet existing environmental regulations for carbon dioxide. Some portfolios exceeded the compliance requirements. For example, the Stakeholder Portfolio was designed to achieve a lower carbon footprint than is likely to be required. Vectren tracks the carbon footprint and other emission measures as a measure of environmental compliance and stewardship.

2.2.3.2 SO_2 and NOx Footprint Reductions from 2012-2015 Baseline

Vectren also tracks the sulfur dioxide emission reductions and the nitrous oxide reductions (both regulated by the EPA) over time, which are measured from an average of the 2012-2015 baseline period.

2.2.4 Balance and Flexibility/Diversity Metrics

2.2.4.1 Concentration on One Technology and Number of Technologies Deployed

Vectren must be in a position to be able to quickly adapt to changing market and regulatory conditions. If Vectren relies heavily on the economic performance of any one technology, such as natural gas or coal, higher than anticipated fuel costs for one technology could expose customers to higher prices than a more balanced portfolio. A measure of protection is to have a diverse portfolio that deploys multiple technologies in the resource mix. This approach forms natural hedges in case any single technology becomes obsolete through technological change.

2.2.4.2 Number of Distinct 24/7 Baseload Units

Customers are better off if Vectren has multiple 24/7 baseload facilities to protect against supply disruptions that could impact an individual site, including transmission failures, outages, or other disruptions.

2.2.4.3 Remote Stations

Portfolios that have stations far removed from its load centers are more subject to transmission congestion, transmission failures, or price spikes than local generation.

2.2.4.4 Net Sales

Higher net sale reflects a generation “cushion” created with generation that is available to serve new customers or enable plant retirement. This cushion enables Vectren to satisfy new or growing expected load without exposing customers to wholesale energy market volatilities. In the case of plant retirement, having this cushion allows Vectren to select the optimal time to retire a resource without risking excessive exposure to wholesale energy market volatility.

In addition, duct firing provides economic peaking capacity. Building in duct firing capability during the initial construction of a combined cycle gas fire plant provides

savings and reduces future down time compared to adding the capability later. This consideration also justifies adding capacity in advance of expected need.

2.2.5 Cost-Risk Tradeoff

This trade-off combines two often competing objectives (expected costs and standard deviation) to find the portfolios that meet both objectives. The expected costs are derived using the NPVRR method, while the standard deviation risk is a measure of how much volatility is included in the price movements.

2.2.6 Local Economic Impact

Vectren also considered the impact of portfolios on regional jobs and tax base. Professors from the University of Evansville conducted this economic impact analysis, assessing the impact of coal-fired unit closures and constructing/operating replacement generation within the Vectren service territory.

2.3 DEFINE BASE CASE AND BOUNDARY SCENARIOS

2.3.1 Base Case

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

- Vectren and MISO energy and demand (load)
- Henry Hub and delivered natural gas prices
- Illinois Basin minemouth and delivered coal prices
- National carbon (CO_2) prices
- Capital costs and associated cost curves for various supply side (generation) and demand side resource options
- On- and off-peak power prices

The long-term energy and demand forecast for the Vectren service territory was developed for Vectren by Itron, a leading forecasting consultant in the U.S. The forecast is based on historical residential, commercial, and industrial usage and drivers such as appliance saturation and efficiency projections, electric price, long-term weather trends, customer-owned generation, and several demographic and economic factors. More information can be found in Section 4, CUSTOMER ENERGY NEEDS.

For natural gas, coal, and carbon, Vectren used a "consensus" base case view of expected prices by averaging forecasts from several sources. This helps to ensure that reliance on one forecast or forecaster does not occur. For natural gas and coal, 2016 spring forecasts from Ventyx, Wood Mackenzie, EVA, and PIRA are averaged. For carbon, forecasts from Pace Global, PIRA, and Wood Mackenzie are averaged. Note that spring 2016 forecasts were not available from Ventyx or EVA at the time inputs were created.

Burns & McDonnell provided current costs associated with various generation and storage technologies (single cycle gas turbine, combined cycle gas turbine, combined heat and power, solar, wind, and batteries), while projected cost curves were developed by Pace Global.

DSM costs were developed by escalating 2016 costs with the help of Dr. Richard Stevie, Vice President of Forecasting with Integral Analytics. He created two models using EIA data to develop growth rates used to apply to current costs.

On- and off-peak power price forecasts were developed by Pace Global using the base case assumptions described above, together with Pace Global's view of the greater MISO market, in the AURORAxmp power dispatch model. These key drivers constitute the base case assumptions. More information on modeling inputs can be found in Section 6, SCENARIOS: OPTIMIZATION MODEL INPUTS & ASSUMPTIONS.

2.3.2 Alternative Scenarios

It is important to test technologies against a variety of future market conditions, not just a base or reference case. Hence, Vectren, with the support of Pace Global, selected six alternative scenarios to provide boundary conditions for testing the technologies and portfolios that would be subjected to a full risk assessment (with hundreds of scenarios tested later in the process).

Vectren worked with Pace and also received input from Vectren stakeholders to identify future uncertainties. Major uncertainties were grouped into regulatory risk, technology risk, and market risk.

Using the base case as a starting point, a number of boundary scenarios were developed along three primary axes. The first axis is regulatory, with a high regulatory scenario and a low regulatory scenario. The second axis is technological, with only a high technology scenario (technological innovation is assumed to either continue at the present rate or at an accelerated rate, but not at a "low" rate). The third axis is economic, with a low market/economy scenario and a high market/economy scenario. From these three primary axes come five scenarios that provide a wide range of conditions in which to evaluate various portfolio planning strategies. Additionally, Vectren evaluated a large customer load scenario where Vectren assumes a large load addition of 100 MW in 2024; all else is equal to the base case scenario.

In order to maintain a consistent methodology when crafting the five scenarios[14] from the base case scenario, the forecasting period was divided into short-term (2016-2018), medium-term (2019-2025), and long-term (2026-2036) periods. In the short-term, the market drivers (load, gas, coal, carbon, and capital costs) for all five alternative scenarios are expected to remain the same as the base case scenario. In the medium-term, the market drivers for each alternative scenario (1) stay the same as the base

[14] Also included a scenario where Vectren acquires a 100 MW load addition in 2024; all else is equal to the base scenario.

case scenario, (2) move upward to reach one standard deviation above the base case value by the medium-term timeframe midpoint of 2022, or (3) move downward to reach one standard deviation below the base case value, also by 2022. In the long-term, the market drivers for each alternative scenario maintain their position (same as base case scenario or +/- one standard deviation above/below the base case scenario) or move toward an endpoint in 2036 that is in between +/- one standard deviation. In some cases and for some scenarios, these drivers may push past +/- one standard deviation above/below the base case. For example, in the high regulatory scenario, CO_2 prices push upward past one standard deviation above the base case in order to provide a boundary condition in line with the independent Synapse report[15] forecast for CO_2 prices.

The six scenarios were designed to be consistent with the stochastic distributions (200 iterations) developed for the risk analysis, but on a much more limited scale (six scenarios).

Vectren selected the following scenarios to illustrate the range of potential outcomes:

- Base large load addition;
- A high and a low regulatory case;
- A high and a low economic case; and
- A high technology case.

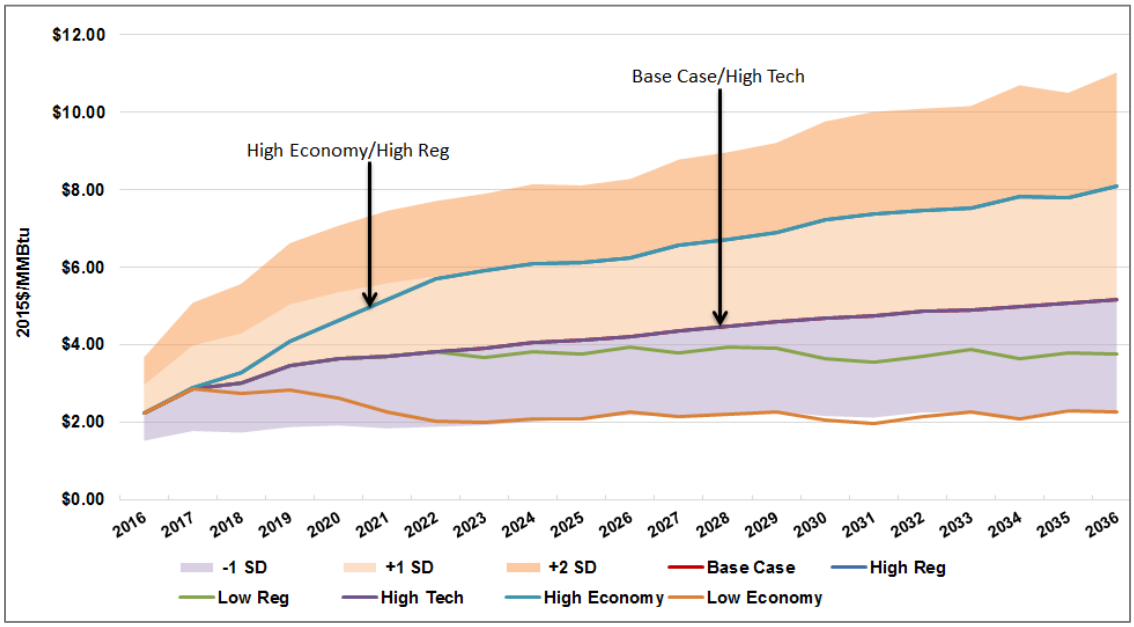
In addition, a consensus between Vectren's staff and its consultants was used to develop directionally whether gas prices, coal prices, load, technology capital costs, retirements and builds, and both carbon emission prices and power prices would move up or down under each of those scenarios. This process was followed more to illustrate what might happen under each of these scenarios in a consistent manner with the risk analysis than to specifically model new regulations or certain technologies.

[15] Synapse Energy Economics, Inc., "Cutting Electric Bills with the Clean Power Plan," March 2016

The six alternate scenarios (described in Section 6 of this document) consist of narrative descriptions of the short-term (2016-2018), medium-term (2019-2025), and long-term (2026-2036) trends in each of the key driver categories described above as well as specific annual or monthly numbers that reflect a shift away from the base case in the medium- to long-term. All scenarios are assumed to mirror the base case in the short-term, though some minor trending apart may begin to occur by 2018. By the middle of the medium-term (2022), each of the drivers will have moved up or down (or stay the same) by one standard deviation relative to the base case, depending on the scenario. By the end of the long-term (2036), each of the drivers will again be one standard deviation above the base case, at the base case, or one standard deviation below the base case.

An illustration of this methodology is given in the graph below for natural gas prices (in constant 2015 dollars). All gas prices begin at $2.23/MMBtu in 2016 and then rise to approximately $2.87/MMBtu in 2017, after which base case gas prices gradually trend upward to $5.13/MMBtu in 2036 while gas prices in the other scenarios either follow the base case or trend higher or lower, depending on the scenario's coordinated input direction. The high technology scenario mirrors that of the base case, while the high economy scenario and high regulatory scenario both move upward to reach +1 standard deviation above the base case in 2022, then remain at +1 standard deviation through the end of the forecast. The low economy scenario sees natural gas prices moving downward to -1 standard deviation below the base case in 2022, and then remains at -1 standard deviation through 2036. Finally, the low regulatory scenario sees natural gas prices trending with the base case through the medium-term, followed by a period of no growth in prices past $4.00/MMBtu.

Figure 2.3 – Natural Gas Price Scenarios, Delivered to Indiana (2015$/MMBtu)



The convention of +/-1 standard deviation 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 and 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 standard deviations above the historical average, whereas they typically cannot fall below zero (or approximately two standard deviations below the historical average).

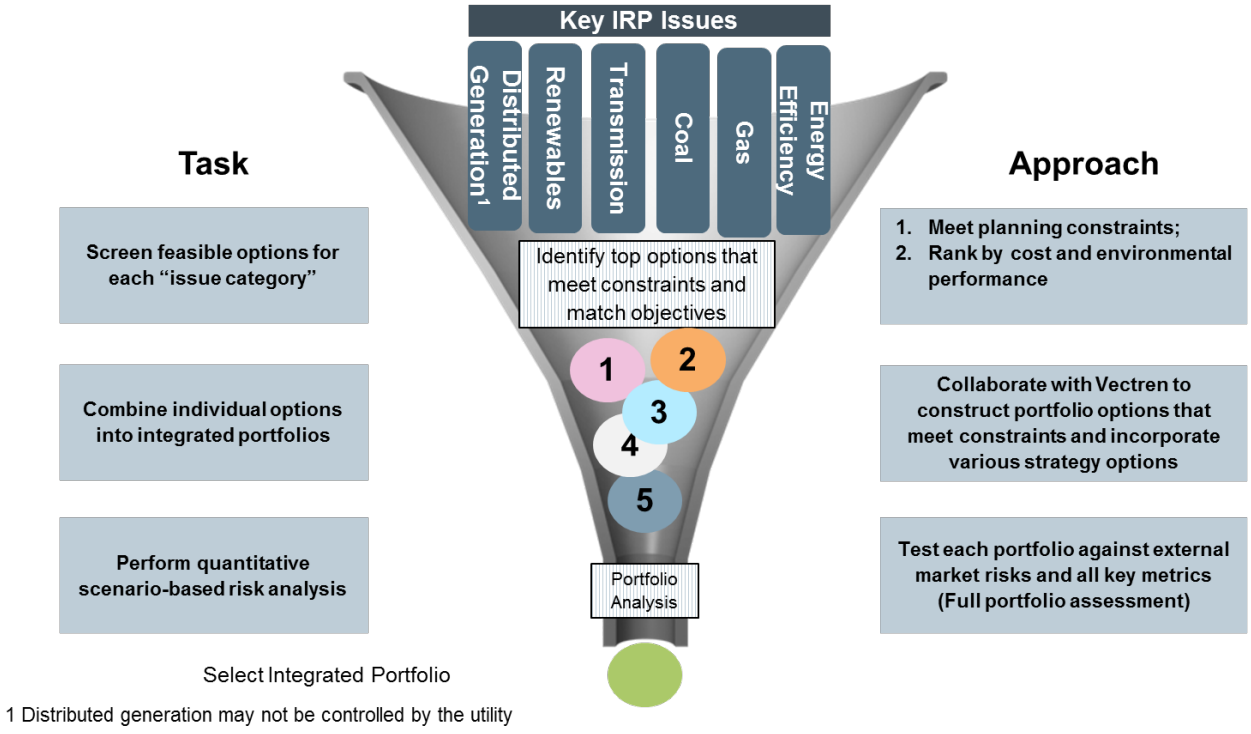
The graphical descriptions of values for each of the key metrics (e.g. load, gas prices, coal prices, technology costs, carbon prices, and power prices) are shown in Section 6.2.2, Coordinated Forecasts for Alternate Scenarios.

2.4 SCREENING ANALYSIS

Burns & McDonnell performed a technology assessment to look at the multitude of different options for power supply (a total of 36 technologies, including renewables, storage, natural gas (including CHP), and coal). To facilitate efficient and timely

modeling, a screening process was developed to filter the technology choices to a smaller data set based on expected operations and levelized cost. The full range of 36 technologies was filtered through this process. The following steps were performed:

Figure 2.4 – Structured Screening Process to Address Issues Efficiently

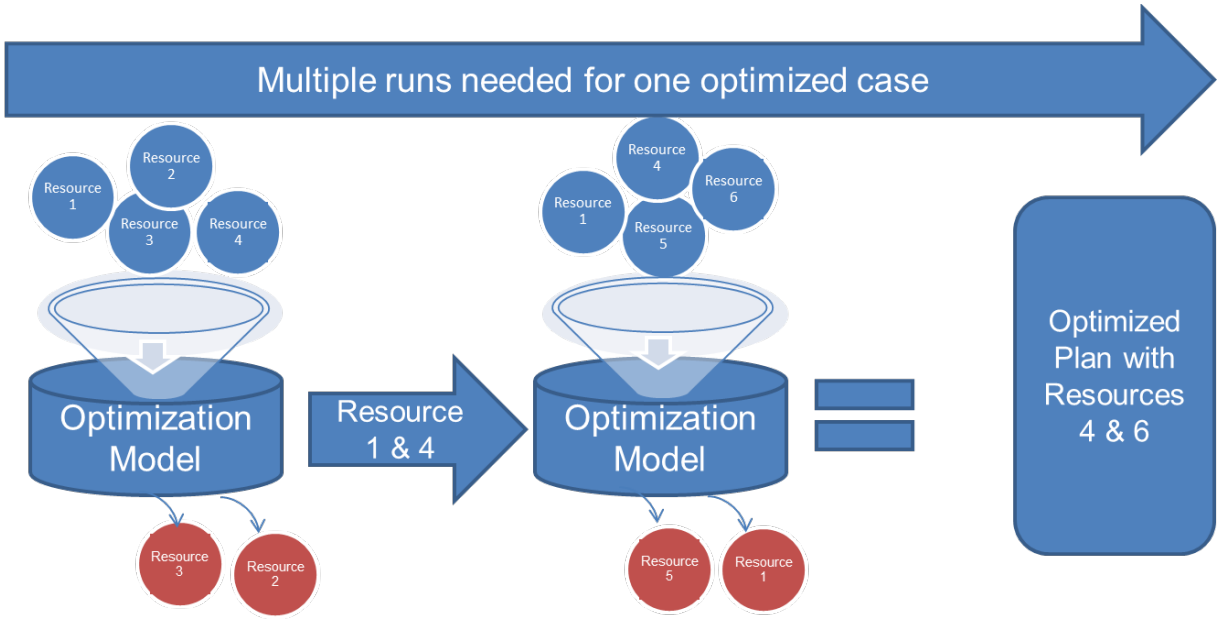


To assess the alternatives on equal footing, Burns & McDonnell performed a busbar, or levelized cost of electricity comparison, for each of the 36 options, focusing on investment costs, operation and maintenance costs, fuel costs, and emissions costs. This screening process allowed for a direct comparison of the anticipated cost of ownership from base load, intermediate, peaking, renewables, and storage alternatives. This step resulted in the elimination of several technologies that performed poorly on a levelized cost basis.

As a next step, the remaining options along with existing facility and demand side alternatives were screened in the Strategist optimization model for the base case and

each of the six scenarios defined in Section 2.3. Due to limitations within the model, not all resource alternatives may be screened in one run. Vectren evaluated more resource alternatives than ever before (coal retirement, existing plant retrofits, multiple blocks of energy efficiency, and demand response, as well as 36 new resource alternatives). In order to accommodate this wide range of options, an iterative process was followed. The model was run with several alternatives. Viable options were kept for the next model run, uneconomic options were screened out, and new options were added in for evaluation. The process was then repeated until all resources were considered and an optimized plan was developed with a small number of resource options for each of the scenarios provided. The illustration below shows the screening process.

Figure 2.5 – Illustrative Example of Strategist Optimization Modeling Process



From this analysis and other objective factors, a list of portfolios was formed in the next stage.

2.5 PORTFOLIO SELECTION

Careful consideration was given to the selection of portfolios in order to address a wide range of objectives, strategies, future market outcomes, and stakeholder concerns; a total of 15 Vectren portfolios were developed for consideration.

First, optimized portfolios were created using Strategist for the base case and each of the six alternate scenarios. The optimized cases produced the least cost portfolio for each of the potential future scenarios, given the modeling inputs. As mentioned above, each scenario represented a possible future state with coordinated inputs for gas, coal, CO_2, market power prices, etc. The intent of this analysis was to produce a wide range of portfolios to test in the risk analysis; however, this modeling produced seven portfolios that looked very similar with a heavy reliance on gas resources and varying levels of energy efficiency. Some included renewables in the late 2020s through the 2030s.

While optimized portfolios are helpful in the analysis process, they may not identify the portfolios that perform well when considering risk and uncertainty. Recognizing this reality and taking stakeholder input into consideration, Vectren worked to develop several diversified portfolios to test in the risk analysis.

During Vectren's public IRP stakeholder meeting on Friday, July 22, 2016, Vectren held a portfolio development workshop to gain input from stakeholders on additional portfolios to be considered within the IRP analysis. The general consensus among the 17 participants was that Vectren should develop a diversified portfolio that moves away from a significant amount of coal by 2025 while renewables and energy efficiency increase. Over the long term, all coal should be retired while renewables and energy efficiency further increase. Vectren used the information gathered from the session to develop two stakeholder portfolios. The first includes some coal, a heavy reliance on renewables and energy efficiency, and some gas in 2024. The second stakeholder

portfolio transitions away from coal altogether by 2024, and replaces it with gas, renewables, and storage.

Finally, Vectren worked to develop several alternate portfolios to test. Portfolios can qualitatively be developed in several ways. One can simply consider various portfolio choices, with trial and error, running them through the optimization tool. Another way is futures based, which is how Vectren's optimized portfolios were developed. Each optimization run resulted in a least cost portfolio for each possible future. A third approach is theme based (all coal, all gas, all renewables, diversified, etc.), which is what Vectren focused on when developing several "diversified portfolios." As a benchmark, Vectren developed the business as usual case (nearly all coal to closely align with Vectren's current portfolio). The optimized base case produced another theme (nearly all gas).

Vectren believes there is value in a balanced portfolio as a way to reduce risk. By having a balanced set of resources available to serve customer load (gas, coal, energy efficiency, wind, solar, etc.), Vectren can reduce the reliance on any one resource type. For example, if gas prices spike or rise more quickly than expected, a portfolio that is nearly all gas has more risk of increasing customer bills. Vectren developed and tested five diversified portfolios with various levels of energy efficiency, demand response, gas, coal, solar, and wind. Below are the 15 portfolios that were tested (Business as Usual, 7 optimized portfolios[16], 2 stakeholder portfolios, and 5 diversified portfolios). More information about these portfolios can be found in Section 7, SCREENING ANALYSIS.

A. Business As Usual (Continue Coal) Portfolio
B. Base Scenario (aka Gas Heavy) Portfolio (Optimized)
C. Base + Large Load Scenario Portfolio (Optimized)
D. High Regulatory Scenario Portfolio (Optimized)

[16] Optimized portfolios were created by Strategist modeling, optimizing on least cost for each scenario (possible future state).

E. Low Regulatory Scenario Portfolio (Optimized)
F. High Economy Scenario Portfolio (Optimized)
G. Low Economy Scenario Portfolio (Optimized)
H. High Technology Scenario Portfolio
I. Stakeholder Portfolio
J. Stakeholder Portfolio (Cease Coal 2024)
K. FBC3, Fired Gas, & Renewables Portfolio
L. FBC3, Fired Gas, Early Solar, & EE Portfolio
M. FBC3, Unfired Gas .05, Early Solar, EE, & Renewables Portfolio
N. Unfired Gas Heavy with 50 MW Solar in 2019 Portfolio
O. Gas Portfolio with Renewables Portfolio

2.6 RISK ANALYSIS

The Risk Analysis of each of the portfolios was developed by Pace Global using EPIS' AURORAxmp dispatch model. There were several steps to this process:

- The first step was to develop the input distributions and correlation coefficients for each of the major market and regulatory drivers, including load growth (and shape), gas prices, coal prices, carbon prices, technology capital costs, and power prices. This was done by considering volatility and correlations of each factor in the short term, midterm, and long term.
- The second step was to run a probabilistic model (Monte Carlo) which selected 200 possible future states over the 20 year period. This also formed the basis for the scenario inputs development.
- Portfolios were then run through simulated dispatch for the 200 possible future states using a tool called AURORAxmp. This tool dispatches existing units, builds, and retires units on the basis of least cost optimization for each portfolio combination for each sampled hour over the planning horizon. AURORAxmp will assume that Vectren's portfolio is constant but will allow for economic builds and retirements to occur throughout the region in each scenario based on economic

criteria. Vectren generation, costs, emissions, etc. were tracked for each iteration over time.

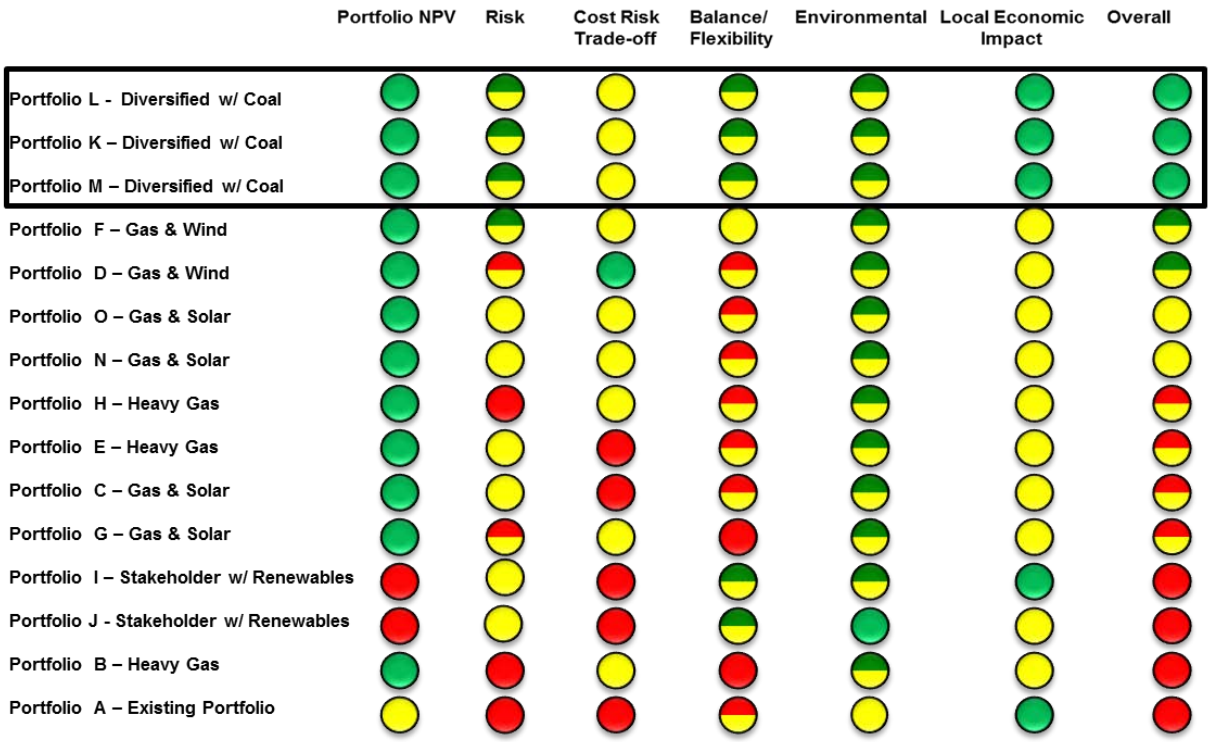
- Next, values for each metric were tracked across all 200 iterations and presented as a distribution with a mean, standard deviation, and other metrics as needed.
- These measures were used as the bases for evaluation in the risk analysis.

More information on the risk analysis can be found in Section 7.2.1, Uncertainty (Risk) Analysis.

2.7 SELECTION OF PREFERRED PORTFOLIO

Selection of the preferred portfolio was based on how well each portfolio met multiple objectives as outlined in Section 2.3, DEFINE BASE CASE AND BOUNDARY SCENARIOS, under 200 iterations representing different, but cohesive and plausible market condition scenarios. The selection process consisted of several comparisons illustrating each portfolio's performance measured against competing objectives. The goal is to create the right balance between satisfying the competing objectives as illustrated below. The preferred portfolio delivered the best balance of performance across all competing metrics when viewed across the full range of 200 iterations. To help illustrate tradeoffs, Vectren utilized a balanced scorecard, as shown below in Figure 2.6 and further discussed in Section 7.2, EVALUATE PORTFOLIO PERFORMANCE.

Figure 2.6 – Identifying and Evaluating Tradeoffs



SECTION 3
PUBLIC PARTICIPATION PROCESS

3.1 PUBLIC PARTICIPATION PROCESS

Vectren believes in the importance of stakeholder engagement. Vectren's objectives for stakeholder engagement are as follows:

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

IRP stakeholders include, but are not limited to, Vectren residential, commercial, and industrial customers, regulators, customer advocacy groups, environmental advocacy groups, Vectren shareholders, and elected officials.

The 2016 IRP analysis was heavily influenced by stakeholder input, beginning with input from stakeholders on Vectren's 2014 IRP and ongoing interaction with other energy company stakeholder processes to glean best practices. Additionally, Vectren utilized the IURC director's report to help guide continuous improvement efforts. As a direct result of these engagements, Vectren publically committed to and incorporated several improvement opportunities for the 2016 IRP, listed below:

- Vectren constructed scenarios (possible future states) with coordinated data inputs with a well-reasoned narrative
- Vectren conducted a probabilistic risk analysis to explore the outer bounds of probability
- Future energy company-sponsored energy efficiency was modeled as a resource (not built into the load forecast)
- Vectren evaluated if retirement made sense for any of Vectren's existing coal generating units within the 20-year time frame under each scenario

- Vectren continues to monitor Combined Heat and Power (CHP) developments and included CHP as a resource option
- Vectren considered conversion of coal units to gas
- Renewable options were fully considered in this analysis
- Updated the IRP document format to be more readable

Another commitment that all Indiana investor-owned utilities, including Vectren, made was to help educate stakeholders on the IRP process. As such, Vectren's 2016 engagement with stakeholders began in February by participation in a joint utilities Integrated Resource Plan Stakeholder Education Session. Duke Energy Indiana, Indiana Michigan Power (I&M), Indianapolis Power & Light Company (IPL), Northern Indiana Public Service Company (NIPSCO), and Vectren jointly presented an educational session to discuss the foundation of the IRP process. This all-day meeting was hosted on February 3, 2016. Topics covered at the meeting included load forecasting, resource options, scenarios & sensitivities, Regional Transmission Operators (RTO), and resource modeling. Recordings and materials were posted to www.vectren.com/irp as a resource for stakeholders who want to know more about the general process.

Three public stakeholder meetings were held at Vectren headquarters in Evansville, IN. Dates and topics covered are listed below:

- April 7, 2016
    - Vectren IRP Process Overview
    - Discussion of Uncertainties
    - Long-term Energy and Demand Forecast
    - Customer-Owned Distributed Generation
    - 2016 IRP Technology Assessment Generation Resource Alternatives
    - Generation Retrofit Alternatives
    - Energy Efficiency Modeling Discussion
- July 22, 2016

- Environmental Compliance
- Base Case/Modeling Inputs
- Busbar Analysis and Optimization Modeling
- Scenario Development
- Stakeholder Input to Portfolio Selection

- November 29, 2016
  - Presentation of the Preferred Portfolio
  - Optimization Modeling Results and Portfolio Development
  - Risk Analysis Results

Additionally, Vectren held a DSM Modeling Information Session on October 14, 2016 with the Vectren DSM Oversight Committee, which includes the Office of Utility Consumer Counselor (OUCC) and Citizens Action Coalition (CAC). Additionally, Indiana Utility Regulatory Commission (IURC) staff attended. Other Vectren stakeholders participated via webinar. The main topics discussed were energy efficiency modeling inputs, including energy efficiency pricing and how energy efficiency was modeled on a consistent and comparable basis with supply side options (power generation options).

Meeting materials, workshop results, and summaries of each meeting can be found on www.vectren.com/irp and also in Technical Appendix Attachment 3.1 Stakeholder Materials.

3.2 STAKEHOLDER INPUT

During the course of the 2016 IRP, stakeholders provided their input in several ways: 1) verbal feedback through question/answer sessions during public stakeholder meetings; 2) through participation in Vectren stakeholder workshops; and 3) via written feedback/requests.

Vectren worked diligently to have an open forum for stakeholders to voice questions/concerns and make suggestions on the IRP analysis. Each Vectren

stakeholder meeting was opened by Carl Chapman, Chairman, President, and Chief Executive Officer of Vectren. He and other senior management, Vectren subject matter experts, and expert consultants actively participated in each meeting to help address stakeholder questions/concerns. Additionally, Vectren addressed stakeholder questions outside of public meetings via irp@vectren.com in a timely manner.

During the first stakeholder workshop on April 7, 2016 Vectren held a session to discuss future uncertainties to be considered in scenario development. The following topics were raised by stakeholders:

- Consider additional environmental regulations that have not yet been proposed
- Factor in the Clean Power Plan (CPP) compliance costs
- Consider how electric vehicle technology affects the plan
- Consider distributed generation risk
- Consider diversifying generation
- Consider political/regulatory risk
- Consider additional cogeneration being developed within the Vectren territory

Vectren agrees that these are key uncertainties and included them within scenario development. Please see Section 6.2, DEVELOPMENT OF ALTERNATE SCENARIOS for more information.

During the second public stakeholder meeting on July 22, 2016 Vectren held a workshop to gather input from stakeholders to gain their insight on a preferred resource portfolio. Two stakeholders (Valley Watch and the Sierra Club) made presentations to the audience. Their meeting materials can be found in Technical Appendix Attachment 3.1 Stakeholder Materials. Following these presentations, stakeholders formed several groups and provided feedback on their preferred resource portfolios.

The general consensus among the participants was that Vectren should develop a diversified portfolio that moves away from a significant amount of coal by 2025 while

renewables and energy efficiency increase. Over the long term, all coal should be retired while renewables and energy efficiency further increase. Several stakeholders expressed concern for the local economic impact if all coal were to be retired in the near to midterm.

Information gathered at this session was used to develop two stakeholder portfolios that were fully tested in the risk analysis. One portfolio kept two coal units through 2035, and the other retired all coal by 2035. For a full description of workshop results, please see Technical Appendix Attachment 3.1 Stakeholder Materials. These portfolios are described in Section 7 Developed Portfolios. Additionally, risk analysis results can be found in Section 8.1, SCORECARD COMPARISON.

On October 14, 2016 Vectren held discussions with stakeholders on EE modeling for the IRP. A stakeholder suggested that breaking the link between EE selected in the near term versus long term as costs increase over time may constrain the model as it could result in the model not selecting EE in the short term. Vectren requested feedback/suggestions from stakeholders on how we could model differently (i.e., model in 3 year increments) and no specific feedback was provided at the time.

Based on stakeholder feedback, Vectren performed additional analysis which looked at the competitiveness of EE over a 3-year block from 2018-2020 rather than selecting the block for entire study period. The 3-year timeframe was selected in order to provide insights into cost effectiveness of EE programs through the next DSM and IRP filing. The analysis results showed no blocks of EE in the lowest NPV plan under the base scenario. EE Blocks 1-4 represented a cost increase of 0.07% over a 20-year Strategist NPV, while EE Blocks 1-8 resulted in a cost increase of 0.96%. The results indicated that blocks 1-4 in 2018-2020 are relatively similar cost as a plan without any additional blocks of EE.

On November 2, 2016 Vectren received a position paper from Ms. Jean Webb, a residential Vectren customer. Her positions are included in Technical Appendix Attachment 3.1 Stakeholder Materials. Included in the paper was a suggestion to review Lazard's Unsubsidized Levelized Cost of Energy Analysis Version 9.0. In Ms. Webb's paper she mentioned that "Lazard's reported that universal solar ranged from $43 to $70 per MWh, whereas Vectren's levelized numbers were from $190 to $210 per MWh."

Vectren has carefully considered many different technologies to potentially supply customer power, including renewable energy from solar power and would suggest that the numbers Ms. Webb references do not fully capture the cost and potential energy output reflective of a solar project located in southwestern Indiana. The $43 to $70 per MWh levelized cost of solar referenced from the Lazard study – per the footnote included within the paper – "Assumes 30 MW system in high insolation jurisdiction (e.g., Southwest U.S.). Does not account for differences in heat coefficients, balance-of-system costs or other potential factors". Further, the costs presented by Lazard do not include site-specific and owner-specific conditions such as land, permitting, legal fees, and transmission/distribution interconnection. These costs cannot be ignored when considering a solar project compared to other alternatives.

Vectren reviewed and illustrated the impact of different assumptions to the levelized cost of solar at its last public stakeholder meeting (held on November 29, 2016), noting that capacity factor and total cost to build are two of the more impactful assumptions. Vectren believes the costs assumed for a solar project used within this IRP are reasonable.

In the final Vectren IRP Stakeholder meeting held on November 29, 2016 a stakeholder asked if health care costs were included in the local economic impact analysis. They were not included within the economic impact analysis. Vectren worked with the University of Evansville to understand the economic impact to the local community

should Vectren coal plants shut down. The software that they utilized does not include a mechanism for calculating health impacts. However, health impacts are considered within known and expected EPA regulations, which were factored into the IRP analysis.

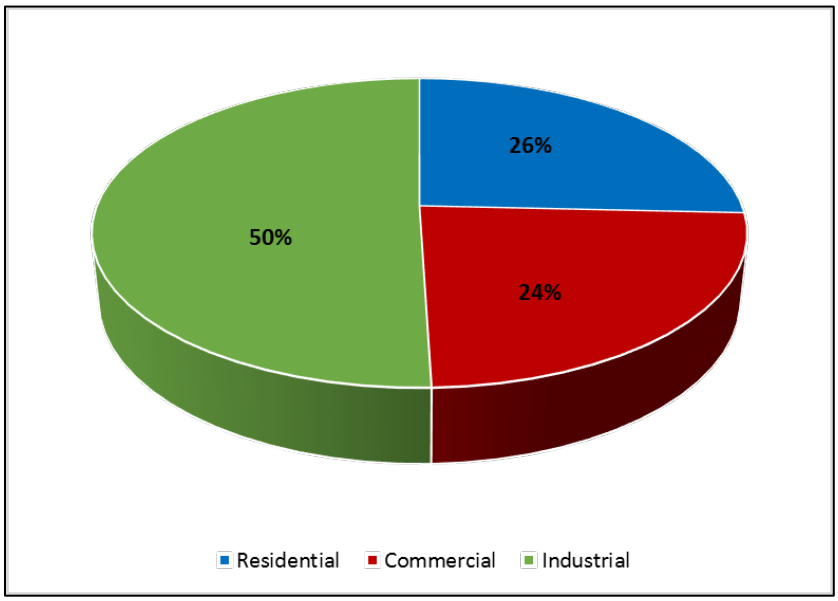
According to EPA, the Clean Air Act (CAA) was designed by Congress to protect public health and welfare from different types of air pollution. The CAA requires EPA to establish national ambient air quality standards for criteria pollutants based upon levels deemed necessary to protect public health, and in the case of "primary" standards, levels deemed necessary to not only protect public health in general but also the health of sensitive populations such as asthmatics, children and the elderly. In addition there are specific provisions to address hazardous or toxic air pollutants that pose health risks which are technology based. Congress requires EPA to issue "maximum achievable control technology (MACT) emission standards which are reviewed every 8 years. As part of the review, EPA is required to give consideration to whether more stringent, risk-based standards are required to protect public health with an ample margin of safety. Since EPA clean air standards, both national ambient air quality standards and public health-based risk standards for hazardous air pollutants already take public health into account, there is no basis for trying to further account for health impacts from the preferred portfolio.

SECTION 4
CUSTOMER ENERGY NEEDS

4.1 CUSTOMER TYPES

Vectren serves approximately 144,000 electric customers in Southwest Indiana. The service area includes a large industrial base with industrial customers accounting for approximately 50% of sales in 2015. The residential class accounted for 26% of sales and the commercial class 24% of sales. Total system 2015 energy requirements (including losses) were 5,737 GWh with system peak (hour of maximum demand) reaching 1,089 MW. 2015 hourly system load data can be found in Technical Appendix 4.2 2015 Vectren Hourly System Load Data. The weather-normalized peak estimate for 2015 was 1,035 MW. Figure 4.1 shows 2015 class-level sales distribution.

Figure 4.1 – 2015 Vectren 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 over ten years of historical energy and demand data within the sales and demand forecasts. This data is maintained by Vectren 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. 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 Moody's Economy.com, 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. Vectren's peak demand is typically in summer when temperatures are hottest. Air conditioning drives summer usage. Normal weather data is obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. Vectren utilizes data over a 30-year period for the sales forecast and a 10-year period for the demand forecast in order to capture recent weather activity.

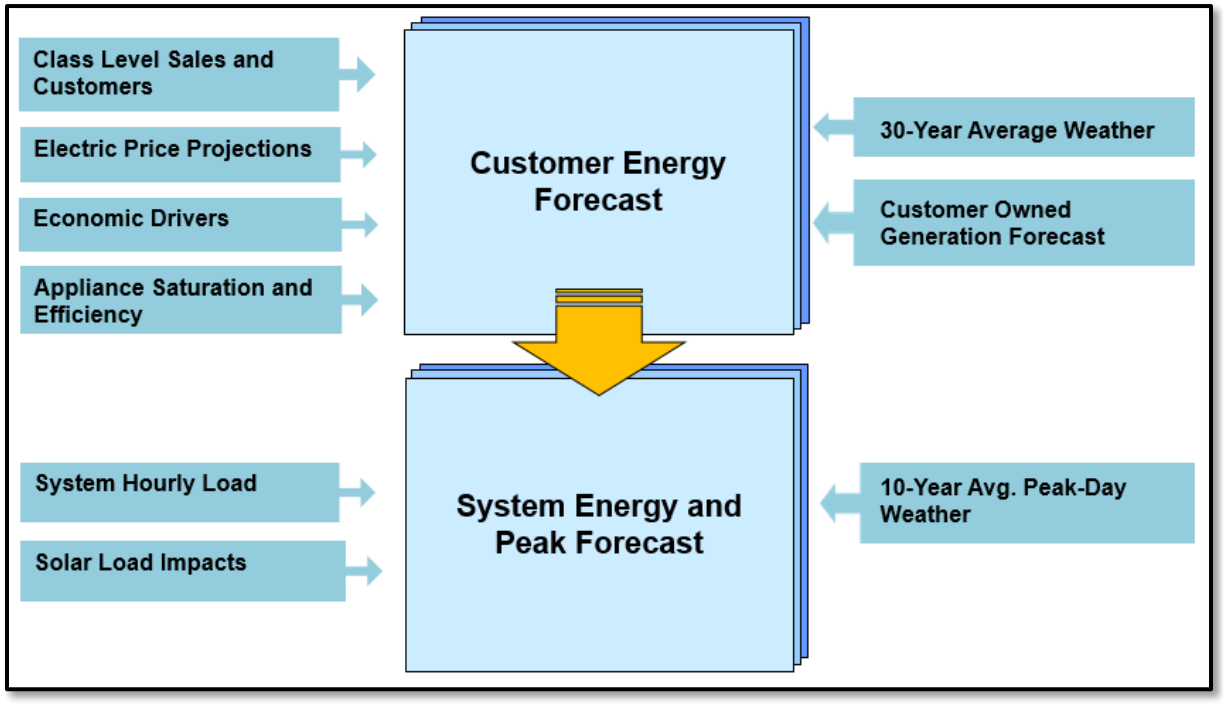
Itron, Inc. provides regional Energy Information Administration (EIA) historic and projected data for equipment efficiencies and market shares. This data captures projected changes in equipment efficiencies based on known codes and standards and market share projections over the forecast period, including 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 has been adjusted to Vectren's service territory based on the latest appliance saturation survey data.

4.3 MODEL FRAMEWORK

The long-term energy and demand forecast was developed from the customer class total and end-use sales forecast. Customer class (residential, commercial, industrial, and street lighting) sales forecasts were based on monthly sales forecast models that related customer usage to weather conditions, economic activity, price, and end-use ownership and efficiency trends. The relationship was estimated using linear regression models. Energy requirements were then derived by adjusting the sales forecast upwards for line losses. Peak demand was forecasted through a monthly peak-demand linear regression model that related peak demand to peak-day weather conditions and end-use energy requirements (heating, cooling, and other use) derived from the class sales forecasts. 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 were forecast using SAE models. Industrial sales were forecast using a generalized econometric model that related industrial sales to seasonal patterns and industrial economic activity. Street light sales were forecast using a simple seasonal trend model. The demand model is an SAE peak model.

4.4 CUSTOMER OWNED DISTRIBUTED GENERATION

Distributed generation (DG) is an electrical source interconnected to Vectren'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 Vectren'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 over)

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 Vectren. Conversely, when a DG system produces more power than the customer's load, excess power can be sent back to Vectren's electric system through a program called net metering. The customer is charged the retail rate for the net power that they consume.

It should be noted that Vectren's forecast of customer owned solar generation is a market based forecast; Vectren did not limit the forecast to 1% of Vectren's installed capacity, consistent with current regulations.

4.4.1 Current DG

As of December 2015, Vectren had approximately 130 residential solar customers and 15 commercial solar customers, with an approximate installed capacity of 1.2 MW. Based on recent solar installation data, the residential average size is 7.8 KW, while the commercial average system size is 16.9 KW. Vectren has incorporated a forecast of customer owned photovoltaic systems into the sales and demand forecast.

Vectren is aware of one large CHP system that is currently being installed within the Vectren service area. A CHP system is projected to be online in 2017. Vectren monitors Combined Heat and Power (CHP) developments in its service area and adjusts the load forecast for any known, future customer owned CHP installations.

4.4.2 Solar DG Forecast

The primary factor driving system adoption is customer economics. Based on analysis of state-level system adoption, Itron has found a strong correlation between customer adoption and simple payback. 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. On an aggregate basis, simple payback also works well to explain leased system adoption; return on investment drives the leasing company's decision to offer leasing programs.

Solar investment payback is calculated as a function of system costs, federal and state tax credits and incentive payments, retail electric rates, and treatment of excess generation (solar generation returned to the grid); for this forecast, Vectren assumed excess generation is credited to the customer at retail energy rates.

Itron developed a solar adoption model that predicts residential solar saturation by relating historical residential solar saturation to simple payback period. The results of this model were then multiplied by the residential customer forecast to determine the number of residential systems expected to be installed. The installed solar capacity

forecast is the product of the solar customer forecast and average system size (measured in kW).

In the commercial sector there have been too few adoptions to estimate a reasonable model; low commercial system adoption is found across the country. Itron believes limited commercial adoption reflects higher investment hurdle rates, building ownership issues (i.e., the person that owns the building often does not pay the electric bill), and physical constraints as to placement of the system. For this forecast, Itron assumed that there would continue 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 of December 2015, the saturation of residential solar customers was about 0.1% of customers. This is expected to be 4.1% (approximately 5,300) by 2036. Commercial saturation is expected to grow to 2.8% over the same time frame.

By 2036, it is expected that over 50 MW of installed customer owned solar capacity will be in place, generating over 67,000 MWhs of energy. The impact of solar generation on system peak demand is a function of the timing between solar load generation and system hourly demand. For example, system peak is generally around 4:00 pm, while maximum solar output is at noon. Even though solar capacity reaches over 50 MW by 2036, solar load reduces Vectren's system peak demand by only 16 MW. The table below shows the forecast of customer owned solar generation, which has been netted out of Vectren's sales and demand forecast.

Figure 4.3 – Solar Capacity and Generation

Year	Total Generation MWh	Installed Capacity MW	Demand Impact MW
2016	3,143	2.6	0.8
2017	8,341	6.9	2.2
2018	16,603	13.6	4.3
2019	23,681	18.3	5.8
2020	35,097	27.9	8.9
2021	44,497	34.5	11.0
2022	47,641	36.0	11.4
2023	49,054	37.0	11.8
2024	50,574	38.1	12.1
2025	51,874	39.2	12.5
2026	53,297	40.2	12.8
2027	54,712	41.3	13.1
2028	56,253	42.4	13.5
2029	57,532	43.4	13.8
2030	58,974	44.5	14.2
2031	60,390	45.6	14.5
2032	61,933	46.6	14.8
2033	63,216	47.7	15.2
2034	64,726	48.8	15.5
2035	66,223	50.0	15.9
2036	67,856	51.1	16.2
CAGR 2017-2036	11.7%	11.1%	11.1%

4.4.3 Potential Effects on Generation, Transmission, and Distribution

Net metering customers currently offset a small amount of load on each respective distribution circuit, which has not caused significant operational issues for Vectren. At higher levels of DG penetration, Vectren 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. A mitigation strategy would need to be developed to control voltage at acceptable levels.

- **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. A mitigation strategy would need to be implemented to correct for the change in the system's operating characteristics.
- **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. A mitigation strategy would need to be implemented to correct for the change in the system's operating characteristics.
- **Short term load forecast uncertainty** – At higher levels of DG penetration, load forecasting becomes more difficult. DG resources work to offset the customer's load, but their output can be variable depending upon weather conditions. Load forecasting techniques would need to be more granular and would need to incorporate provisions for DG response to short-term weather conditions.
- **Capacitor banks on the distribution feeders** – Capacitor banks are used to improve power factor and also raise 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, the capacitor banks may no longer be in the optimal location for power factor correction or voltage changes. This could negatively impact the power factor and voltage level of the circuit, if a circuit has a high enough DG concentration.

Vectren'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 Vectren incurs to provide retail electric service. DG customers (who generate a portion of their own electricity but still rely on the electric grid) avoid paying the fixed costs of the grid that are included in the energy charge, which leads to Vectren's under recovery of the cost of providing service. Over time, as base rates are updated periodically, these costs shift to non-net metering customers, resulting in a subsidy being paid to net metering customers.

4.5 BASE ENERGY AND DEMAND FORECAST

For the IRP filing, the long-term energy and demand forecast does not include energy savings from future DSM programs; DSM activity is now considered a supply option and not a reduction to demand. Excluding DSM, total energy requirements and peak demand (after 2017) are expected to average 0.5% annual growth over the next 20 years. The table below shows Vectren's energy and demand forecast; the forecast includes the impact of customer owned distributed generation and customer EE outside of energy company sponsored programs but excludes future energy company sponsored DSM program savings. For more information on Vectren long-term energy and demand forecasts, including load shapes, see Technical Appendix Attachment 4.1 2016 Vectren Long-Term Electric Energy and Demand Forecast Report.

Figure 4.4 – Energy and Demand Forecast[17]

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2016	5,913,198		1,164		896	
2017	5,309,089	-10.2%	1,094	-6.0%	825	-7.9%
2018	5,368,438	1.1%	1,104	0.9%	836	1.2%
2019	5,397,983	0.6%	1,109	0.5%	841	0.6%
2020	5,449,432	1.0%	1,117	0.7%	851	1.2%
2021	5,451,608	0.0%	1,118	0.0%	852	0.1%
2022	5,472,381	0.4%	1,122	0.4%	855	0.4%
2023	5,497,316	0.5%	1,126	0.4%	858	0.4%
2024	5,529,346	0.6%	1,132	0.5%	863	0.6%
2025	5,549,264	0.4%	1,136	0.4%	866	0.3%
2026	5,573,239	0.4%	1,141	0.4%	869	0.4%
2027	5,600,616	0.5%	1,147	0.5%	873	0.5%
2028	5,637,119	0.7%	1,154	0.6%	878	0.6%
2029	5,662,724	0.5%	1,159	0.5%	882	0.4%
2030	5,687,266	0.4%	1,165	0.5%	885	0.4%
2031	5,711,753	0.4%	1,170	0.5%	888	0.4%
2032	5,744,206	0.6%	1,177	0.6%	893	0.5%
2033	5,766,607	0.4%	1,183	0.4%	896	0.3%
2034	5,796,861	0.5%	1,189	0.5%	900	0.5%
2035	5,814,295	0.3%	1,193	0.3%	902	0.2%
2036	5,837,850	0.4%	1,198	0.4%	905	0.4%
CAGR 2017-2036		0.5%		0.5%		0.5%

4.6 DISCUSSION OF BASE LOAD, INTERMEDIATE LOAD, AND PEAK LOAD

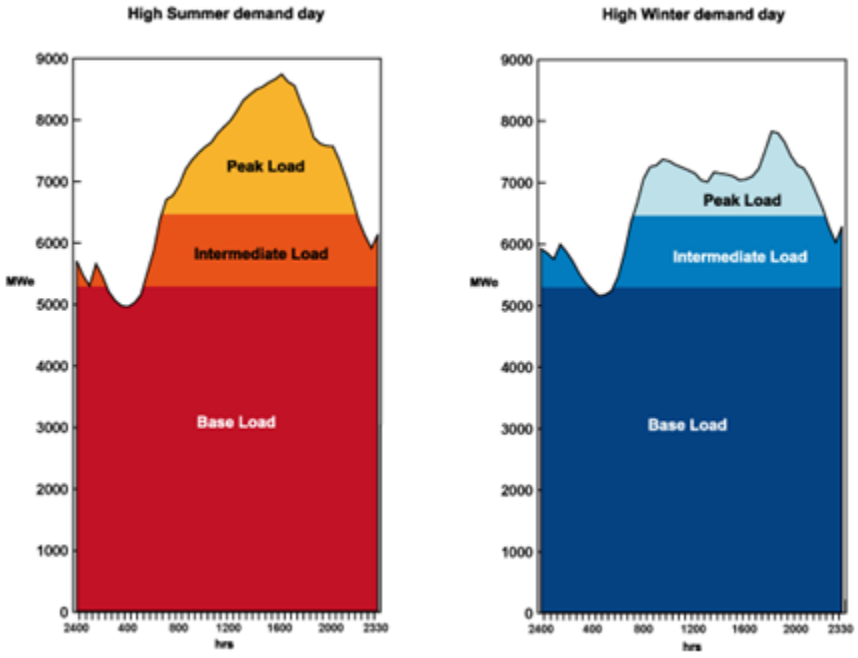
There are three levels of electric load: base load, intermediate load, and peak load. Each level is served by different resource types. Base load is the minimum level of demand on an electrical supply system over 24 hours. Base load is primarily served by power plants which can generate consistent and 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 evening. Peak load is the

[17] 2016 2016 IRP sales and demand forecast provided to MISO differed slightly in order to match MISO's requirements which necessitated the following two adjustments : 1) incorporated the preferred level of DSM, and 2) adjustment made on the supply and demand side to account for expected customer co-generation unit in 2017.

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, Vectren uses August as the peak month. Typically, peak demand is served by units that can be switched on quickly when additional power is needed.

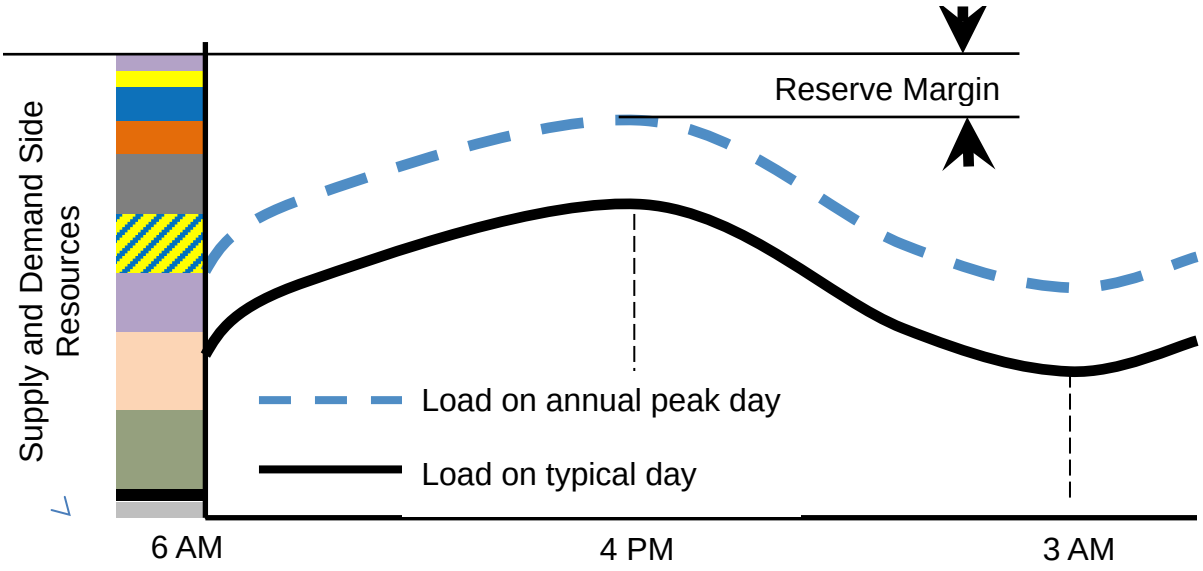
The graphic below shows an illustrative example of summer and winter peak load.

Figure 4.5 – Typical Load Curve Illustrations (Summer and Winter)



Energy companies must have enough resources (supply side generation or demand side energy efficiency & demand response) to meet the annual peak load, plus a reserve margin for reliability purposes, which is required by Vectren's regional transmission operator. The illustration below shows the load on a typical day and load on the peak day with the reserve margin requirement.

Figure 4.6 – Illustration of Load Curve and Planning Reserve Margin



4.7 PLANNING RESERVE MARGIN DISCUSSION

The planning reserve margin requirement is set by MISO (Midcontinent Independent System Operator), which is Vectren's Regional Transmission Operator (RTO).

4.7.1 MISO

MISO, headquartered in Carmel, Indiana, with additional offices in Little Rock, Arkansas, Metairie, Louisiana, and Eagan, Minnesota, was approved as the nation's first Regional Transmission Organization in 2001. Today, MISO manages one of the world's largest energy and operating reserves markets; the market power capacity was 175,600 MW as of June 1, 2016. This market operates in 15 states and 1 Canadian province.

MISO administers its Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff). As a vertically integrated energy company with the responsibility and obligation for serving load within the MISO footprint, Vectren has integrated many functions with the operating procedures of MISO. This integration involves the coordinated operation of its transmission system and generating units, and

the functions range from owning and operating generation and transmission to complying with certain reliability standards. These standards include the planning and operation of resources to meet future load needs that are set by the North American Electric Reliability Corporation (NERC) and the regional reliability entity Reliability First Corporation, both of which are overseen by the Federal Energy Regulatory Commission (FERC).

With a native peak load of about 1,160 MW, Vectren is less than 1% of the MISO market footprint and is 1 of 36 local balancing authorities. In addition, the Vectren transmission system supports multiple municipalities. The total control area or Local Balancing Area (LBA) is approximately 1,300 MW.

4.7.2 MISO Planning Reserve Margin Requirement (PRMR)

MISO helps to ensure Resource Adequacy by establishing the Planning Reserve Margin (PRM) with resources at their installed capacity rating at the time of the system-wide MISO coincident peak load. The PRM is a measure of available capacity over and above the capacity needed to meet normal peak demand levels. Reserve margin and reserve capacity are synonymous. For a producer of energy, it refers to the ability of a producer to generate more energy than the system normally requires. Regulatory bodies usually require producers to maintain a constant reserve margin of 10-20% of normal capacity as insurance against breakdowns in part of the system or sudden increases in energy demand. PRMs are needed to cover: planned maintenance, unplanned or forced outages of generating equipment, de-ratings in the capability of generation resources and demand response resources, system effects due to reasonably anticipated variations in weather, and variations in customer demands or forecast demand uncertainty.

4.7.2.1 Mechanics of the PRMR

The PRM calculation is driven by the following: external non-firm support, load forecast uncertainty, load, and generation. External non-firm support refers to the diversity of

load between MISO and neighboring systems outside of MISO that allow for limited support and transfer of capacity. An example would be generators in PJM providing capacity to MISO load. Load forecast uncertainty exists due to the variability of economics and weather that impact the demand for energy and increases the uncertainty of forecasts. A robust economy with extreme weather patterns typically leads to higher energy demand. Conversely, a depressed economy with moderate weather tends to lead to reductions in energy demand. Additionally, the ability, or lack there-of, to predict weather and the economy and whether load growth will be positive or negative greatly impacts the amount of reserves needed to reliably meet load needs. The greater the Load Forecast Uncertainty, the greater the PRMR. Finally, generation as it is modeled in terms of capacity and firm imports, impacts the PRM calculation based on the size and outage rate of the generators. A year in which there are a large number of generator outages with long durations will increase the PRM. The chart below is intended to show the impact on the PRMR due to increases in the individual driver (external non-firm support, load forecast uncertainty, load, and generation).

Figure 4.7 – Planning Reserve Margin Drivers

	External Non-Firm Support	Load Forecast Uncertainty	Load (Forecast Demand)	Generation (Size and Outages)
Increase in the Driver	⇧	⇧	⇧	⇧
Impact on the PRM%	⇩	⇧	⇩	⇧

MISO coordinates with stakeholders to determine the appropriate PRM for the applicable planning year based upon the probabilistic analysis of the ability to reliably serve MISO Coincident Peak Demand for that planning year. The probabilistic analysis uses a Loss of Load Expectation (LOLE) study that assumes no internal transmission limitations within the MISO Region. MISO calculates the PRM such that the LOLE for

the next planning year is one day in 10 years, or 0.1 days per year. The minimum amount of capacity above Coincident Peak Demand in the MISO Region required to meet the reliability criteria is used to establish the PRM. The PRM is represented as an unforced capacity (PRM UCAP) requirement based upon the weighted average forced outage rate of all Planning Resources in the MISO Region.

The LOLE study sets the Local Reliability Requirement (LRR) for the planning year for each of MISO's zones. MISO's Zone 6[18] in planning year 2016-2017 is required to have a UCAP PRM of 7.6%. This number changes each year based on changes in the factors listed above. Given that the PRM changes from year to year, it is good to have some resources available above the PRM. The full MISO report can be found in Technical Appendix Attachment 4.3 MISO LOLE Study Report.

Since 2013, MISO's Reserve Margin has declined. As MISO starts to operate at or near the Planning Reserve Margin Requirement, it is likely that MISO will begin calling Emergency Operating Procedures more often than in the past to access emergency-only resources, such as Load Modifying Resources (LMR) and Behind the Meter Generation (BTMG). Emergency Operating Procedures (EOPs) guide system operator actions when an event occurs on the electric system that has the potential to, or actually does, negatively impact system reliability.

[18] MISO Zone 6 covers much of Indiana and a small portion of Kentucky.

SECTION 5
RESOURCE OPTIONS

5.1 CURRENT 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. 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. The supply stack is the variable cost of production of power by each generating unit, stacked from least cost to most cost. Units that cost less to run are dispatched before units that cost more. Vectren's larger coal units tend to be base load units. Intermediate units may cycle on and off frequently and may sit idle seasonally. Vectren's smallest coal unit sees this type of service. Peaking units have the most expensive energy costs per kWh and are only started when energy demand exceeds 24/7 baseload capacity. Currently, Vectren's gas turbines are dispatched during these peak periods to assure reliability. These peaking units may only run for a few hours and remain idle for long periods of time until called on.

Vectren's current generation mix consists of approximately 1,360 megawatts (MW) of installed capacity. This capacity consists of approximately 1,000 MW of coal fired generation, 245 MW of gas fired generation, 3 MW of landfill gas generation, 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 32 MW.

The table below references both installed capacity (ICAP) and unforced capacity (UCAP). Installed capacity is also referred to as nameplate capacity. This is the maximum output that can be expected from a resource. Unforced capacity is the amount of capacity that can be relied upon to meet peak load. MISO uses UCAP for planning purposes. The UCAP accreditation recognizes that all resources are not equally reliable or, in some cases, capable of achieving their design output. MISO uses a three-year reliability history and a weather normalized capability verification to determine the UCAP accreditation of each unit. Vectren used the MISO 2016-2017

UCAP accreditation values along with the MISO UCAP planning reserve margin requirements (7.6% PRM) in the current IRP.

Figure 5.1 – Vectren Generating Units

Unit	Installed Capacity ICAP (MW)	Unforced Capacity UCAP (MW)	Primary Fuel	Unit Age
AB Brown 1	245	238.3	Coal	1979
AB Brown 2	245	223.1	Coal	1986
FB Culley 2	90	85.6	Coal	1966
FB Culley 3	270	263.2	Coal	1973
Warrick 4	150	132.2	Coal	1970
AB Brown 3	80	71.7	Gas	1991
AB Brown 4	80	72.7	Gas	2002
BAGS 2	65	57.6	Gas	1981
Northeast GT 1&2	20	18.9	Gas	1963 / 1964
Blackfoot	3	3 - N/A[19]	Landfill Gas	2009

5.1.1 Coal

The AB Brown Generating Station (ABB), located in Mt. Vernon, IN, consists of two coal fired units, each with an installed capacity of 245 MW. ABB Unit 1 began commercial operation in 1979, while ABB Unit 2 became operational in 1986.

Both AB 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 bisulfite (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 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

[19] The Blackfoot landfill gas generator is connected at the distribution level and is not part of the transmission connected generation network managed by MISO. Therefore, it is not assigned a MISO UCAP value.

captured via an electrostatic precipitator (ESP) on Unit 2. Unit 1 was upgraded to a fabric filter in 2004. The PM that is captured, also known as fly ash, is part of Vectren'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.

AB Brown Units 1 and 2 burn Illinois basin bituminous coal, which is mined in Knox County, IN and is delivered via rail.

The AB Brown plant site also has two natural gas turbine generators which are discussed in Section 5.1.2, Natural Gas.

The FB Culley Generating Station (FBC), located near Newburgh, IN, 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.

FBC is scrubbed for sulfur dioxide (SO_2) emissions, utilizing a forced oxidation flue gas desulfurization (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 Vectren's beneficial reuse program, is shipped, via barge, to a facility near New Orleans, LA where it is used in the manufacture of drywall. Sulfur trioxide (SO_3) is removed from both units via a dry sorbent injection (DSI) system installed in 2015. FBC Unit 3 is also scrubbed for nitrogen oxides (NO_x) with a selective catalytic reduction (SCR) system that was installed in 2003. NO_x control on FBC Unit 2 is through the use of low NO_x burners. Mercury (Hg) 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. Particulate matter (PM) is captured via an electrostatic precipitator (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 Vectren'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.

The FB Culley units burn Illinois basin bituminous coal, which is mined in Knox County, IN and delivered via truck.

Warrick Unit 4 (Warrick) located near Newburgh, IN is a coal fired unit operated and maintained by Alcoa Power Generating Inc. Vectren maintains 50% ownership of Warrick Unit 4. It has an installed 300 MW unit which began commercial operation in 1970. Vectren's 50% interest is equal to 150 MW.

Warrick Unit 4 is scrubbed for sulfur dioxide (SO_2) emissions, utilizing a forced oxidation flue gas desulfurization (FGD) process which was retrofitted in 2009. The captured SO_2 is converted into synthetic gypsum within the system, and (as part of Vectren's beneficial reuse program) is shipped via truck to a facility near Shoals, IN where it is used in the manufacture of drywall. Sulfur trioxide (SO_3) is removed via a dry sorbent injection (DSI) system installed in 2010. Unit 4 is also scrubbed for nitrogen oxides (NO_X) with a selective catalytic reduction (SCR) system which was retrofitted in 2004. Mercury (Hg) 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. Particulate matter (PM) is captured via an electrostatic precipitator (ESP). The PM that is captured, also known as fly ash, is part of Vectren'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. Vectren purchases coal for its share of Warrick Unit 4, which is mined in Knox County, IN and is delivered by truck.

5.1.2 Natural Gas

The AB Brown Generating Station (ABB) located near Mt. Vernon, IN 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.

Broadway Avenue Generating Station (BAGS) located in Evansville, IN consists of two gas fired SCGT peaking units. BAGS Unit 1 became operational in 1972 and had an installed capacity rating of 50 MW. This unit has been mothballed and is earmarked for retirement. BAGS Unit 1 is not currently included in Vectren's capacity analysis. BAGS Unit 2 began operation in 1981 and has an installed capacity of 65 MW.

The Northeast Gas Turbine (NEGT 1) facility located in Evansville, IN consists of two natural gas fired peaking units. NEGT 1 began commercial operation in 1963 and has an installed capacity of 10 MW. NEGT 2 became operational in 1964 and also has an installed capacity of 10 MW.

5.1.3 Renewables

The Blackfoot Clean Energy Facility located in Winslow, IN 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.

5.1.4 DSM

5.1.4.1 INTRODUCTION

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

Since 1992, Vectren has operated a Direct Load Control (DLC) program called Summer Cycler that reduces residential and small commercial air-conditioning and water heating electricity loads 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. Vectren's Summer Cycler program has served Vectren and its customers well for more than two decades, but emerging technology is now making the program obsolete.

Furthermore, between 2010 and 2015, Vectren's DSM programs reduced demand by approximately 44,000 kW and provided annual incremental gross energy savings of approximately 217,000,000 kWh.

The table below outlines the estimated program penetration on a yearly basis since Vectren programs began in 2010. Gross cumulative savings, less opt out savings, 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 5.2 – Gross Cumulative Savings

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh) - Less Opt Out Savings	Percent of Sales Achieved (Cumulative)
2010	5,616.87	2.52	0.04%
2011	5,594.84	18.30	0.33%
2012	5,464.75	62.29	1.14%
2013	5,459.11	122.06	2.24%
2014[20]	3,498.69	176.74	5.05%
2015	3,223.81	217.25	6.74%

[20] Cumulative savings as a percent of eligible sales saw a higher increase from 2013 to 2014 due to the SB 340's opt-out provision. In 2014, Vectren's eligible sales decreased at a higher rate than achieved savings. For this reason, Vectren achieved higher savings as a percent of eligible sales.

5.1.4.2 2016-2017 Plan Overview

Current Energy Efficiency Programs

On March 23, 2016, the IURC issued an Order approving Vectren's 2016-2017 Energy Efficiency Plan (2016-2017 EE Plan) pursuant to Section 10. Consistent with the 2014 IRP, the framework for the 2016-2017 EE Plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 80% of eligible load. Below is a listing of residential and commercial & industrial programs offered in 2016-2017. For full program descriptions including the customer class, end use of each program, and participant incentives provided by the programs, please refer to the 2016-2017 EE Plan detail found in the Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan.

Residential Programs

- Residential Lighting
- Home Energy Assessments and Weatherization
- Income Qualified Weatherization
- Appliance Recycling
- Energy Efficient Schools
- Residential Efficient Products
- Residential New Construction
- Multi-Family Direct Install
- Residential Behavior Savings
- Residential Smart Thermostat Demand Response

Commercial & Industrial Programs

- Small Business Direct Install
- Commercial & Industrial Prescriptive Rebates
- Commercial & Industrial New Construction
- Commercial & Industrial Custom
- Conservation Voltage Reduction (CVR)

The 2016-2017 plan was included as a resource in the resource optimization model (Strategist) and has an assumed average measure life of 10 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 10.3 DSM Appendix.

Figure 5.3 – 2016-2017 Energy Efficiency Plan Savings

	2016*		2017**	
Sector	Net MWh Energy Savings	Net MW Demand Savings	Net MWh Energy Savings	Net MW Demand Savings
Residential	18,072	4.8	16,332	3.8
Commercial & Industrial	16,474	2.4	15,864	2.4
Total	34,546	7.3	32,196	6.2

*2016 Operating Plan used for 2016
**2016-2017 Filed Plan used for 2017

5.1.5 Demand Response

Vectren's tariff currently includes two active demand response programs: the Direct Load Control and interruptible options for larger customers. Demand response programs allow Vectren to curtail load for reliability purposes. Vectren's tariff also includes a MISO demand response tariff, in which no customers are currently enrolled given the absence of an active demand response program within the MISO market at this time. For purposes of modeling DSM for the IRP, Vectren assumed an active MISO demand response market beginning in 2020.

5.1.5.1 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 (LMR). Under the program, Vectren compensates customers in exchange for the right to initiate events to reduce air-conditioning and water-heating electric loads during summer peak hours. Vectren can initiate a load control event for several reasons, including: to balance utility system supply and demand, to alleviate

transmission or distribution constraints, or to respond to load curtailment requests from the Midcontinent Independent Transmission System Operator, Inc. (MISO).

Vectren 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. Vectren also utilizes an outside vendor, The Cadmus Group, to evaluate the DLC program and provide unbiased demand and energy savings estimates.

Cadmus predicts the DLC Program is capable of generating approximately 19.3 MWs of peak demand savings from residential air-conditioning load control and residential water heating load control. As of May 2016, Vectren's DLC Program included over 23,000 customers with a combined total of approximately 31,000 switches. Note that a customer may have more than one switch at a residence or business.

5.1.5.2 Current Interruptible Load

Vectren makes available a credit for qualified commercial and industrial customers to curtail demand under certain conditions. The five customers currently participating provide for a total demand reduction of 35 MW.

5.1.5.3 Smart Thermostats

Pursuant to the IURC approved DSM plan in 2016, Vectren conducted a field study designed to analyze the different approaches of DR that are available through smart thermostats. Between the months of April and May, Vectren installed approximately 2,000 smart thermostats (1,000 Honeywell and 1,000 Nest) in customer homes. Vectren leveraged these thermostats to manage DR events during the summer in an effort to evaluate the reduction in peak system loads. These smart devices, which reside on the customer's side of the electric meter, are connected to Wi-Fi and reside on the customer's side of the electric meter and are used to communicate with customer's air

conditioning systems. The program provides Vectren with increased customer contact opportunities and the ability to facilitate customers' shift of their energy usage to reduce peak system loads. In 2017, Vectren will work with an independent evaluator to conduct a billing analysis to measure the effectiveness of the program, including specific performance of the Nest and Honeywell products.

If the program is successful, Vectren will pursue significant expansion in 2018 and beyond, using the technology that best serves its customers' needs. If approved by the Commission, Vectren anticipates replacing DLC switches with smart thermostats over time; indications are the benefits associated with this emerging technology far outweigh the benefits associated with DLC switches.

5.1.5.4 Other Innovative Rate Design

Vectren 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 may be considered at such time as the required technology upgrades are implemented.

5.2 POTENTIAL FUTURE OPTIONS MODELING ASSUMPTIONS

5.2.1 Coal Technologies

Coal power plants 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.

Another type of coal technology evaluated was the Integrated Gasification Combined Cycle (IGCC). IGCC produces a low calorific value syngas (synthetic natural gas) from coal or solid waste which can be fired in a combined cycle power plant. The gasification

process itself is a proven technology used extensively for chemical production of goods such as ammonia for fertilizer. See Figure 5.4 for further details on the coal technologies evaluated.

Figure 5.4 – Coal Technologies

Coal			
Operating Characteristics and Estimated Costs	**Supercritical Pulverized Coal 500 MW**	**Supercritical Pulverized Coal 750 MW**	**2x1 Integrated Gasification CC**
Base Load Net Output (MW)	425	637.5	525
Base Load Net Heat Rate (HHV Btu/kWh)	10,500	10,200	10,500
Base Project Costs (2015$/kW)	$5,570	$5,080	$3,928
Fixed O&M Costs (2015$/kW-year)	$31.90	$21.20	$36.30

5.2.2 Natural Gas Technologies

5.2.2.1 Simple Cycle Gas Turbines

Simple cycle gas turbines (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 5.5 for further details on the simple cycle gas turbine technologies evaluated.

Figure 5.5 – Simple Cycle Gas Turbine Technologies

Simple Cycle Gas Turbines				
Operating Characteristics and Estimated Costs	**1xLM6000 SCGT**	**1xLMS100 SCGT**	**1xE-Class SCGT**	**1xF-Class SCGT**
Base Load Net Output (MW)	43.4	99.5	90.1	219.8
Base Load Net Heat Rate (HHV Btu/kWh)	9,210	8,840	11,310	9,750
Base Project Costs (2015$/kW)	$1,880	$1,430	$1,230	$650
Fixed O&M Costs (2015$/kW-year)	$26.57	$11.72	$15.83	$7.08

5.2.2.2 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.

For this assessment, a 1x1, 2x1, and 3x1 power block, as shown in Figure 5.6, were evaluated with General Electric (GE) 7F-5 turbines as representative CCGT technologies. A 1x1 CCGT has one gas or steam turbine coupled with one HRSG. A 2x1 has two gas or steam turbines coupled with one HRSG. A 3x1 follows the same pattern. The 2x1 CCGT F class technology was considered for both .04 and .05 versions. The .05 technology is GE's most recent F class offering. See Figure 5.6 for further details on the combined cycle gas turbine technologies evaluated.

Figure 5.6 – Combined Cycle Gas Turbine Technologies

Combined Cycle Gas Turbines				
Operating Characteristics and Estimated Costs[21]	**1x1 7FA.05 CCGT (ABB)**	**2x1 7FA.04 CCGT (ABB)**	**2x1 7FA.05 CCGT (ABB)**	**3x1 7FA.05 CCGT (ABB)**
Duct-Firing	Fired	Fired	Fired	Fired
Base Load (24/7 Power) Net Output (MW)	343	579	690	1039
Incremental Duct-Fired (Peaking) Net Output (MW)	99	167	199	298
Base Load Net Heat Rate (HHV Btu/kWh)	6,590	6,650	6,540	6,520
Incremental Duct-Fired Heat Rate (HHV Btu/kWh)	8,460	8,580	8,450	8,460
Base Project Costs (2015$/Fired kW)	$840	$720	$640	$550
Fixed O&M Costs (2015$/Base Load kW-year)	$12.26	$8.89	$7.46	$5.95

A site selection study that examined Greenfield (potential new power plant sites) and compared Brownfield (existing power plant sites) can be found in Technical Appendix Confidential Attachment 5.2 CCGT Site Selection Report.

Vectren initiated studies to evaluate retrofit options that would repurpose existing coal fired generation assets to use natural gas.

[21] Combined cycle gas turbines are shown as fired configuration at AB Brown site for this table. Reference the Technology Assessment for additional details on duct-firing

5.2.2.3 Refuel Option

The conversion of existing coal fired boilers to burn natural gas instead of coal was studied. Detailed site specific studies were performed to determine costs, MW ratings and expected heat rates (efficiency), total natural gas fuel flow requirements, and projected emissions. More information on the refuel option can be found in Technical Appendix Confidential Attachment 1.2 Vectren Technology assessment Summary Table.

5.2.2.4 Repower Option

The conversion of a coal fired unit to a combined cycle gas turbine CCGT was studied. With a unit repower, the existing coal fired boiler and its associated auxiliary equipment would be decommissioned. The steam supply to the legacy steam turbine and electric generator would be accomplished by way of newly constructed heat recovery steam generators capturing heat from the exhaust gas of newly constructed combustion turbines, each of which would have shaft driven electric generators. Detailed site specific studies were performed to determine costs, MW ratings and expected heat rates (efficiency), total natural gas fuel flow requirements, and projected emissions. More information on the repower option can be found in Technical Appendix Confidential Attachment 1.2 2016 Vectren Technology Assessment Summary Table.

5.2.2.5 Combined Heat and Power (CHP)

Combined Heat and Power (CHP), also known as cogeneration, provides both electricity and useful heating or cooling. CHP captures the benefits of heating or cooling, which is created as a byproduct of electricity production, and can be used to create hot water or steam. CHP is typically most efficient when produced close to the end user. See Figure 5.7 for further details on the CHP technologies evaluated.

Figure 5.7 – Combined Heat & Power Technologies

Combined Heat and Power (CHP)					
Operating Characteristics and Estimated Costs	**1 MW Microturbine**	**3 MW Combustion Turbine Generator**	**5 MW Combustion Turbine Generator**	**10 MW Combustion Turbine Generator**	**15 MW Combustion Turbine Generator**
Base Load Net Output (MW)	1.0	3.2	5.1	10.3	13.6
Base Load Net Heat Rate (HHV Btu/kWh)[1]	6,510	4,460	4,400	4,480	4,450
Base Project Costs (2015$/kW)	$4,746	$7,602	$5,637	$3,874	$2,975
Fixed O&M Costs (2015$/kW-year)	$180.30	$227.86	$172.28	$118.77	$99.55

[1]Heat rates are credited for fuel required to produce equivalent steam output.

CHP technical and operating considerations should include the following: customer electric load and thermal requirements inclusive of a detailed engineering and feasibility review. The matching of high load factor thermal load is key to CHP success. In most cases, electricity is considered the byproduct of the process. It is important to understand the variation in heat and electrical demand (demand profiles) as well as the infrastructure modifications within the customer's facility compared to utility connection.

For this screening process it was assumed that Vectren will own and operate a CHP facility. However, it should be noted that a CHP investment may require customers to own and operate internal electric equipment and/or construct significant electric distribution infrastructure. CHP must be mutually beneficial to the customer and Vectren. It is ultimately a customer decision. Upon review of potential customer sites, Vectren identified a market potential of approximately 30 MWs of matching steam and electric load in the Vectren South service territory. The CHP market potential study can be found in Technical Appendix Confidential Attachment 5.4 CHP Market Potential Study.

5.2.3 DSM

5.2.3.1 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 demand side (DSM) options that can be incorporated into the plan. This process aligns with IURC's proposed Rule 170IAC 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."

In addition, this process aligns with Senate Enrolled Act (SEA) 412 which requires that 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.

Given that, two questions must be addressed. One, how much DSM should be made available as resource options for selection by the IRP process? And two, how does one project the cost of the DSM resource options over a 20-year horizon and increasing market penetration?

5.2.3.2 DSM Availability

Obviously, at one extreme, one could argue that 100% of retail sales of an energy company could be made available for selection as a DSM resource. However, that is not practical as some energy must be consumed in the course of economic activity. At

the other extreme, one could argue that no DSM resource options are required as consumers make their own decisions on the tradeoffs between consumption of energy and investment in more efficient technologies. The result of those decisions would already be reflected in the Company's projection of electric loads.

However, there are barriers to the adoption of more efficient energy using technologies that can be overcome through the implementation of targeted energy company energy efficiency programs. Energy efficiency programs, as marketing programs, encourage customers to adopt higher levels of efficiency earlier than would happen naturally, basically advancing the timing of the energy efficiency. Guidance on the appropriate level of energy efficiency to be made available to the IRP process can be obtained from a market potential study. The Company's market potential study[22] found a Technical Potential of 11%, an Economic Potential of 8.2%, an Achievable High Potential of 6.2%, and an Achievable Low Potential of 3.5%. However, this is only for the years 2015 through 2019.

Another source of information on market potential may be found in a study conducted by the Electric Power Research Institute (EPRI)[23]. This study estimated the potential for the period 2013 through 2035 for the nation as well as selected regions including the Midwest. For the Midwest region, for the full period to the year 2035, the study found a Technical Potential of 23.7%, an Economic Potential of 13.8%, a High Achievable Potential of 11.1%, and an Achievable Potential of 8.9%.

Technical potential is the maximum energy efficiency available, assuming that cost and market adoption of a technology are not a barrier. Economic potential is the amount of energy efficiency that is cost effective, meaning the economic benefit outweighs the cost. The economic potential is measured by the total resource cost test, which

[22] ELECTRIC DEMAND SIDE MANAGEMENT: MARKET POTENTIAL STUDY AND ACTION PLAN, April 2013 prepared by EnerNOC Utility Solutions Consulting.
[23] U.S. Energy Efficiency Potential Through 2035. 1025477 Final Report, April 2014.

compares the lifetime energy and capacity benefits to the incremental cost of the measure. This achievable potential is the amount of energy efficiency that is cost effective and can be achieved given customer preferences. Not all customers will adopt a given technology. For example, CFL light bulbs have been cost effective for many years; however, some people chose not to adopt them for aesthetic reasons. This provides some guidance on the types of potential that the Company could consider for inclusion in its set of DSM resource options.

However, one must consider the impact on these estimates from the fact that larger customers may opt-out of participation in Vectren's energy efficiency programs. As a result of customer opt-outs, 41% of retail sales are not available for consideration in development of DSM resource options. In addition, another adjustment to the available market potential should be taken to capture the level of energy efficiency (EE) impacts expected to be already achieved in the 2013 to 2016 period (when industrial customers were allowed to begin opting out) as represented in the following table.

Figure 5.8 – Vectren Historical Energy Efficiency Impacts

Year	Eligible Retail Sales (GWh)	Gross Incremental Savings (GWh) - Less Opt Out Savings	Gross Cumulative Savings (GWh) - Less Opt Out Savings	Incremental DSM Savings (less opt-out) as a Percent of Eligible Sales	Cumulative DSM Savings (less opt-out) as a Percent of Eligible Sales	Cumulative DSM Savings (less opt-out) as a Percent of Eligible Sales Since 2013
2010	5,616.87	2.52	2.52	0.04%	0.04%	
2011	5,594.84	15.78	18.30	0.28%	0.33%	
2012	5,464.75	43.99	62.29	0.81%	1.14%	
2013	5,479.11	59.77	122.06	1.09%	2.23%	1.09%
2014	3,498.69	54.68	176.74	1.56%	5.05%	3.27%
2015	3,223.81	40.51	217.25	1.26%	6.74%	4.81%
Est2016	3,611.51	42.32	259.57	1.17%	7.19%	5.46%

This implies that the EPRI market potential estimates should be adjusted down to reflect the portion that has already been achieved. Using a conservative estimate of 5% of the

potential already achieved, the remaining Technical Potential is estimated to be 18.7%, Economic Potential is 8.8%, High Achievable Potential is 6.1%, and Achievable Potential is 3.9%.

While some may contend that the full technical 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. Rather, the potential should reflect some consideration of achievability. This can be estimated by taking the ratio of the achievable percentages to the technical potential percentage and applying that to the remaining estimate of technical potential percentage. This means that 46.8% (11.1%/23.7%) of the technical potential would be considered as the remaining High Achievable Technical Potential or 8.8% of retail sales (e.g., 0.468 x 18.7%). Similarly, 37.6% of the technical potential would be considered as the remaining Achievable Technical Potential or 7.0% of retail sales.

The foregoing provides guidance on the level of DSM resource options that should be considered in the IRP analytical process as well as the maximum levels that seem reasonable at a high level.

For the initial performance of the IRP analysis, Vectren chose to make up to 2% of retail sales as DSM resource options available for selection in the IRP process for each year of the 20 year planning horizon. This represents almost 40% of retail sales, far above any reasonable estimate of even technical market potential. The 2% applies to the level of retail sales after reduction for the level of load that has opted out. To facilitate the IRP resource selection process, the 2% of retail sales was broken into 8 blocks of 0.25% each. Taking this over the 20 year horizon means that over 150 incremental blocks of 0.25% each were available to be selected in the IRP process[24]. From this structure, Vectren expects that the appropriate IRP determined cost-effective level of

[24] For the first two years of the planning horizon, 2016 and 2017, the energy efficiency impacts are based upon the plan approved in Cause No. 44645.

EE would be identified. This process should provide substantial insight on the cost-effective level of energy efficiency. The following table represents the structure and the sizes of the blocks.

Figure 5.9 – DSM Resource Options Net of Free Riders

Year	Eligible GWh Conservation Savings	Percent of Eligible Sales Potential	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016										
2017	3,493									
2018	3,525	2.0%	6.986	6.986	6.986	6.986	6.986	6.986	6.986	6.986
2019	3,545	2.0%	7.050	7.050	7.050	7.050	7.050	7.050	7.050	7.050
2020	3,571	2.0%	7.089	7.089	7.089	7.089	7.089	7.089	7.089	7.089
2021	3,577	2.0%	7.141	7.141	7.141	7.141	7.141	7.141	7.141	7.141
2022	3,594	2.0%	7.154	7.154	7.154	7.154	7.154	7.154	7.154	7.154
2023	3,613	2.0%	7.188	7.188	7.188	7.188	7.188	7.188	7.188	7.188
2024	3,640	2.0%	7.227	7.227	7.227	7.227	7.227	7.227	7.227	7.227
2025	3,654	2.0%	7.281	7.281	7.281	7.281	7.281	7.281	7.281	7.281
2026	3,672	2.0%	7.309	7.309	7.309	7.309	7.309	7.309	7.309	7.309
2027	3,692	2.0%	7.344	7.344	7.344	7.344	7.344	7.344	7.344	7.344
2028	3,721	2.0%	7.384	7.384	7.384	7.384	7.384	7.384	7.384	7.384
2029	3,739	2.0%	7.442	7.442	7.442	7.442	7.442	7.442	7.442	7.442
2030	3,755	2.0%	7.477	7.477	7.477	7.477	7.477	7.477	7.477	7.477
2031	3,772	2.0%	7.511	7.511	7.511	7.511	7.511	7.511	7.511	7.511
2032	3,796	2.0%	7.543	7.543	7.543	7.543	7.543	7.543	7.543	7.543
2033	3,810	2.0%	7.592	7.592	7.592	7.592	7.592	7.592	7.592	7.592
2034	3,831	2.0%	7.620	7.620	7.620	7.620	7.620	7.620	7.620	7.620
2035	3,850	2.0%	7.663	7.663	7.663	7.663	7.663	7.663	7.663	7.663
2036	3,876	2.0%	7.701	7.701	7.701	7.701	7.701	7.701	7.701	7.701

The component programs for the blocks are assumed to initially be those approved in Cause No. 44645 and previously described in Section 5.1.4, DSM. For the first two years of the planning horizon (2016 and 2017), it is assumed that the current set of approved programs are being implemented. However, it is expected that the nature of the programs in the blocks may change over time as energy efficiency technology changes.

No minimum level of energy efficiency impacts have been locked in for the planning process. The table provides 0.25% blocks of net impacts which already reflects a 20% adjustment for free riders. Free riders represent those participants that would have implemented the energy efficiency technology without the energy company program.

5.2.3.3 DSM Resource Cost – Base Case

Projecting the cost of the DSM programs that are expected to achieve a 40% level of energy efficiency (EE) over a long period represents a challenge. As a starting point, the cost of the energy efficiency programs approved in Cause No. 44645 is used for the 2017 DSM resource options. The Company's EE portfolio being implemented in 2016 is designed to achieve approximately 36,000 MWh impacts on a net of free-rider basis at a cost of $0.20 per first year kWh[25] ($.03322 per kWh on a levelized basis). Through 2015, the Company has already achieved a reduction of approximately 7% of available 2017 retail sales (total retail sales reduced for opt-outs)[26]. On a net of free-rider basis, the 2016 plan is designed to achieve an additional 1% of available retail sales.

As discussed above, in an effort to allow the IRP model to inform the Company on the cost-effective level of EE to pursue in the resource plan, the Company has provided the IRP model with the ability to select from 8 blocks of EE impacts each year where each block represents 0.25% of retail sales. This represents a possible additional 2% of available retail sales that could be selected each year from 2018 through 2036.

On a cumulative basis, this means that almost 40% of available retail sales could be selected by the IRP process. This is in addition to the approximate 7% already achieved through past EE efforts. Vectren is not aware of any national or regional EE market potential study with a higher estimate of EE potential. In order to identify the cost-effective level of EE in the IRP process, it is imperative that Vectren develop

[25] This value is estimated using the total cost of the program and dividing by the first year of EE savings.
[26] As previously mentioned, the Company has achieved a 3% reduction in total retail sales over the period 2013 through 2015.

estimates of the cost of EE achievement that reflect how the costs could change as EE market penetration increases.

To this end, Vectren retained Dr. Richard Stevie, VP of Forecasting with Integral Analytics, Inc., to provide insights on how the cost to achieve an increment of EE could change as the cumulative EE market penetration rises. Dr. Stevie's recommendation is based upon his research into the relationship between spending on EE programs and the level of first year impacts achieved through the implementation of the EE programs as well as the cumulative level of EE impacts. The research relies upon EE cost and impact data collected through Form 861 by the Energy Information Administration (EIA). A copy of the research study is provided in Technical Appendix Attachment 5.3 Cost of Energy Efficiency Programs. The study found that EE program costs per kWh increase as the cumulative penetration of EE increases, as measured by the percent of retail sales. The primary focus of the research was to examine if and to what extent the program cost of EE changes as the available supply (i.e., retail sales) of EE is consumed through implementation of EE programs. Based upon this research and Vectren's projected level of EE available for selection by the IRP process, Dr. Stevie developed a projected rate of growth in the cost of EE for the first four blocks which cumulatively represent 1% of eligible retail sales each year. This growth rate was applied to each of the first four 0.25% blocks.

The growth rate was developed from two separate econometric models of the EIA data as described in the study provided in Technical Appendix Attachment 5.3 Cost of Energy Efficiency Programs. The results from the two models were averaged to produce a growth rate in cost of 4.12% per 1% of retail sales achievement or 1.04% per 0.25% EE block.

With this first 1% of retail sales, Vectren is planning to achieve an amount of energy efficiency that exceeds an expected high achievable level over the next 20 years. As a result, it is assumed that the second 1% of retail sales must occur at a higher marketing

cost than the first 1% of retail sales. In other words, the methodology is that for the first 1%, for the full planning period, Vectren is achieving actually more than what it should reasonably expect to achieve in the market place. The effort being undertaken is as if Vectren were achieving the full 1% for 20 years or 20% of the market at a base level of cost. To get the next 1%, one has to step up to a higher marketing cost that assumes the first 1% has already been achieved. The next 1% is incremental to the first 1%. It is assumed that Vectren will have to dramatically expand its marketing effort to essentially double the annual impact achievement. This would involve expanded advertising and possibly in person contact to get customers to take action. Essentially the second 1% has to be more expensive, not cheaper, than the first 1%.

As a result, the starting cost for the second 1% of blocks is assumed to be the ending cost (in real dollars) for the first 1%. Then, a different growth rate is applied for the remaining set of four 0.25% blocks available each, or the next 1% of retail sales available for selection. The process of computing the applicable growth rate was similar to that of the first 1%. This resulted in a growth rate of 1.72% per additional 1% of retail sales impacts or 0.43% per 0.25% block. So, this assumes that once the first four blocks have been selected in a year by the IRP, the cost increases first to the cost of the last block of the 1% of retail sales and then by 0.43% per 0.25% block for the 5th to 8th blocks. These growth rates form the basis for projecting how the block costs change for all of the blocks available for selection by the IRP process. The lower growth rate was applied to the second 1% of retail sales (blocks 5 to 8) to allow for economy of operation within a given year, while the higher growth rate was applied to the first 1% of retail sales to try to capture the impact on cost over time. The following table provides the estimated levelized costs used for all of the blocks.

Figure 5.10 – Base Case Cost per kWh[27]

Year	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016	$0.03322	$0.03356	$0.03391	$0.03426	$0.07811	$0.07844	$0.07878	$0.07911
2017	$0.03462	$0.03498	$0.03534	$0.03570	$0.07945	$0.07979	$0.08013	$0.08048
2018	$0.03607	$0.03645	$0.03682	$0.03721	$0.08082	$0.08117	$0.08151	$0.08186
2019	$0.03759	$0.03798	$0.03837	$0.03877	$0.08221	$0.08256	$0.08292	$0.08327
2020	$0.03917	$0.03958	$0.03999	$0.04040	$0.08363	$0.08398	$0.08434	$0.08470
2021	$0.04082	$0.04124	$0.04167	$0.04210	$0.08507	$0.08543	$0.08579	$0.08616
2022	$0.04254	$0.04298	$0.04342	$0.04387	$0.08653	$0.08690	$0.08727	$0.08764
2023	$0.04433	$0.04478	$0.04525	$0.04572	$0.08802	$0.08840	$0.08877	$0.08915
2024	$0.04619	$0.04667	$0.04715	$0.04764	$0.08953	$0.08992	$0.09030	$0.09069
2025	$0.04813	$0.04863	$0.04914	$0.04964	$0.09108	$0.09146	$0.09186	$0.09225
2026	$0.05016	$0.05068	$0.05120	$0.05173	$0.09264	$0.09304	$0.09344	$0.09384
2027	$0.05227	$0.05281	$0.05336	$0.05391	$0.09424	$0.09464	$0.09504	$0.09545
2028	$0.05447	$0.05503	$0.05560	$0.05618	$0.09586	$0.09627	$0.09668	$0.09709
2029	$0.05676	$0.05734	$0.05794	$0.05854	$0.09751	$0.09793	$0.09834	$0.09876
2030	$0.05914	$0.05976	$0.06038	$0.06100	$0.09919	$0.09961	$0.10004	$0.10046
2031	$0.06163	$0.06227	$0.06292	$0.06357	$0.10089	$0.10133	$0.10176	$0.10219
2032	$0.06422	$0.06489	$0.06556	$0.06624	$0.10263	$0.10307	$0.10351	$0.10395
2033	$0.06693	$0.06762	$0.06832	$0.06903	$0.10440	$0.10484	$0.10529	$0.10574
2034	$0.06974	$0.07046	$0.07119	$0.07193	$0.10619	$0.10665	$0.10710	$0.10756
2035	$0.07268	$0.07343	$0.07419	$0.07496	$0.10802	$0.10848	$0.10895	$0.10941
2036	$0.07573	$0.07652	$0.07731	$0.07811	$0.10988	$0.11035	$0.11082	$0.11130

The detailed calculation of the growth rates is provided in Technical Appendix Attachment 5.3 Cost of Energy Efficiency.

5.2.3.4 DSM Resource Cost - Scenario Analysis

The previous discussion provided the Base Case projection of DSM resource costs. However, 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 and stochastic risk analyses. Only time and actual experience with increases in DSM market penetration will provide better guidance on these cost projections.

[27] Costs included in the risk analysis modeling

To that end, high and low DSM resource cost trajectories were developed using the estimated standard errors of the model coefficients used in the development of the Base Case cost projection. These high and low cost trajectories were created by applying plus and minus one standard error to the model coefficients.[28] This produces alternate DSM resource cost growth rates summarized in the following table.

Figure 5.11 – DSM Resource Cost Growth Rates

Sets of Four Blocks	Minus One Standard Deviation	Base Case	Plus One Standard Deviation
First 1%	0.85%	1.04%	1.22%
Second 1%	0.35%	0.43%	0.51%

Applying these alternate growth rates produces the following high and low tables of projected DSM resource costs.

[28] Using the model coefficients and standard errors from the two econometric models referenced in Dr. Stevie's research, the coefficient range is developed by adding the standard error to or subtracting it from the coefficient estimate. For the first model, the coefficient is .278 with a standard error of .084. For the second model, the coefficient is .897 with a standard error of .131.

Figure 5.12 – High Case Cost per kWh: Plus One Standard Deviation

Year	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016	$0.03322	$0.03363	$0.03404	$0.03445	$0.09095	$0.09141	$0.09187	$0.09233
2017	$0.03487	$0.03530	$0.03573	$0.03617	$0.09280	$0.09327	$0.09374	$0.09421
2018	$0.03661	$0.03705	$0.03751	$0.03796	$0.09469	$0.09517	$0.09565	$0.09613
2019	$0.03843	$0.03890	$0.03937	$0.03985	$0.09662	$0.09710	$0.09759	$0.09809
2020	$0.04034	$0.04083	$0.04133	$0.04183	$0.09858	$0.09908	$0.09958	$0.10008
2021	$0.04234	$0.04286	$0.04338	$0.04391	$0.10059	$0.10110	$0.10161	$0.10212
2022	$0.04445	$0.04499	$0.04554	$0.04610	$0.10264	$0.10316	$0.10368	$0.10420
2023	$0.04666	$0.04723	$0.04781	$0.04839	$0.10473	$0.10526	$0.10579	$0.10632
2024	$0.04898	$0.04958	$0.05018	$0.05080	$0.10686	$0.10740	$0.10794	$0.10849
2025	$0.05142	$0.05205	$0.05268	$0.05332	$0.10904	$0.10959	$0.11014	$0.11070
2026	$0.05397	$0.05463	$0.05530	$0.05598	$0.11126	$0.11182	$0.11238	$0.11295
2027	$0.05666	$0.05735	$0.05805	$0.05876	$0.11352	$0.11409	$0.11467	$0.11525
2028	$0.05948	$0.06020	$0.06094	$0.06168	$0.11583	$0.11642	$0.11700	$0.11760
2029	$0.06243	$0.06320	$0.06397	$0.06475	$0.11819	$0.11879	$0.11939	$0.11999
2030	$0.06554	$0.06634	$0.06715	$0.06797	$0.12060	$0.12121	$0.12182	$0.12243
2031	$0.06880	$0.06964	$0.07049	$0.07135	$0.12305	$0.12367	$0.12430	$0.12493
2032	$0.07222	$0.07310	$0.07400	$0.07490	$0.12556	$0.12619	$0.12683	$0.12747
2033	$0.07581	$0.07674	$0.07768	$0.07862	$0.12811	$0.12876	$0.12941	$0.13006
2034	$0.07958	$0.08055	$0.08154	$0.08253	$0.13072	$0.13138	$0.13205	$0.13271
2035	$0.08354	$0.08456	$0.08559	$0.08664	$0.13338	$0.13406	$0.13473	$0.13541
2036	$0.08770	$0.08877	$0.08985	$0.09095	$0.13610	$0.13679	$0.13748	$0.13817

Figure 5.13 – Low Case Cost Per kWh: Minus One Standard Deviation

Year	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016	$0.03322	$0.03350	$0.03379	$0.03407	$0.06700	$0.06723	$0.06747	$0.06770
2017	$0.03436	$0.03465	$0.03495	$0.03524	$0.06794	$0.06818	$0.06841	$0.06865
2018	$0.03554	$0.03585	$0.03615	$0.03646	$0.06889	$0.06913	$0.06938	$0.06962
2019	$0.03677	$0.03708	$0.03739	$0.03771	$0.06986	$0.07011	$0.07035	$0.07060
2020	$0.03803	$0.03835	$0.03868	$0.03901	$0.07084	$0.07109	$0.07134	$0.07159
2021	$0.03934	$0.03967	$0.04001	$0.04035	$0.07184	$0.07209	$0.07234	$0.07260
2022	$0.04069	$0.04104	$0.04138	$0.04174	$0.07285	$0.07311	$0.07336	$0.07362
2023	$0.04209	$0.04245	$0.04281	$0.04317	$0.07388	$0.07413	$0.07439	$0.07465
2024	$0.04354	$0.04391	$0.04428	$0.04465	$0.07491	$0.07518	$0.07544	$0.07570
2025	$0.04503	$0.04542	$0.04580	$0.04619	$0.07597	$0.07623	$0.07650	$0.07677
2026	$0.04658	$0.04698	$0.04738	$0.04778	$0.07704	$0.07731	$0.07758	$0.07785
2027	$0.04818	$0.04859	$0.04901	$0.04942	$0.07812	$0.07839	$0.07867	$0.07894
2028	$0.04984	$0.05026	$0.05069	$0.05112	$0.07922	$0.07950	$0.07977	$0.08005
2029	$0.05155	$0.05199	$0.05243	$0.05288	$0.08033	$0.08061	$0.08089	$0.08118
2030	$0.05333	$0.05378	$0.05424	$0.05470	$0.08146	$0.08175	$0.08203	$0.08232
2031	$0.05516	$0.05563	$0.05610	$0.05658	$0.08261	$0.08290	$0.08319	$0.08348
2032	$0.05706	$0.05754	$0.05803	$0.05852	$0.08377	$0.08406	$0.08436	$0.08465
2033	$0.05902	$0.05952	$0.06003	$0.06053	$0.08495	$0.08524	$0.08554	$0.08584
2034	$0.06105	$0.06157	$0.06209	$0.06262	$0.08614	$0.08644	$0.08675	$0.08705
2035	$0.06315	$0.06368	$0.06422	$0.06477	$0.08735	$0.08766	$0.08796	$0.08827
2036	$0.06532	$0.06587	$0.06643	$0.06700	$0.08858	$0.08889	$0.08920	$0.08951

These cost projections were incorporated into the scenario analyses. The selection of a high or low cost projection depends upon the nature or characteristics of each scenario. Expected direction of power costs is assumed to be one of the key drivers in deciding which of the cost projections should be used in a given scenario.

Scenario 1, The High Regulatory Scenario, is characterized by a heavier reliance on regulations such as the Clean Power Plan (CPP) as well as other potential future regulations focused on reducing carbon emissions. In conjunction with these regulations, it is expected that more stringent codes and standards would be implemented to promote installation of more energy efficient equipment. The stricter efficiency codes and standards will likely shrink the available market potential for energy

company DSM programs, which could make it more difficult to market DSM resources. As a result, the high DSM resource cost projection is employed for this scenario.

Under the Low Regulatory Scenario, it is expected that with a reduced regulatory environment, there would be greater economic growth and thus a larger market for offering DSM programs. The lower regulatory environment could make it easier to market DSM resources. As a result, the low DSM resource cost projection is employed in this scenario.

The High Technology Scenario is characterized by significant advances in solar, wind, and energy storage technologies as well as advances in EE technologies. In addition, it is expected that newer technologies could improve marketing efficiency that makes it easier to attract DSM program participants. As a result, the low DSM resource cost projection is employed for this scenario.

The High Economy/Market Scenario sees faster economic growth which leads to higher growth in energy usage, in the absence of faster technology development. The growth in energy usage will make DSM resources more attractive and cost-effective for program participants. As a result, the low DSM resource cost projection is employed for this scenario.

Under the Low Economy/Market Scenario, the economy is sluggish which keeps load growth low. It is expected that power prices would increase at a slower rate which could make it more difficult to market DSM resources. As a result, the high DSM resource cost projection is employed in this scenario.

Incorporating alternate views of DSM resource costs into the IRP planning process provides a better view on the robustness of the final DSM resource selection.

5.2.3.5 Summary

This DSM Resource process provides EE savings and cost values for over 150 blocks of DSM resources representing almost 40% of available retail sales for potential selection by the IRP analytical model. This level of DSM resource options, exceeding estimates of Technical Potential, provides enough flexibility to the IRP model for identifying and selecting a DSM plan consistent with the IURC and legislative objectives. However, given that there is a potential to exceed the estimate of Technical Potential, adjusted for past impacts already obtained and for achievability, the results of the IRP analytical process need to be checked to ensure that the resulting level of DSM selected is ultimately and practically viable.

5.2.3.6 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 of DSM to be offered in Vectren's service territory is an important outcome of the IRP process. The IRP should determine the appropriate level of DSM to include in the preferred resource plan. However, for Vectren, the IRP is not the appropriate tool to determine which specific programs to include in a DSM plan. Instead, every 2-3 years Vectren 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 test the cost effectiveness of the programs.

5.2.3.7 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 savings of the measure, life of the measure, implementation costs, administrative costs, incremental costs to the participant of the

high efficiency measure, and escalation rates and discount rates. Vectren considers the results of each test and ensures that the portfolio passes the Total Resource Cost (TRC) test as it includes the total costs and benefits to both the energy company 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

Figure 5.14 – Vectren 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
Utility 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)

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 considering only avoided utility supply cost (based on the next unit of generation) in comparison to program costs.
The Ratepayer Impact Measure (RIM) Test shows the impact of a program on all utility customers through impacts in 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 Total Resource Cost (TRC) Test shows the combined perspective of the energy company and the participating customers. This test compares the level of benefits associated with the reduced energy supply costs to energy company programs and participant costs. In completing the tests listed above, Vectren used 10.09% as the weighted average cost of capital, which is the weighted cost of capital that was approved by the IURC on April 27, 2011 in Cause No. 43839.

5.2.4 Demand Response

Demand Response (DR) represents curtailment or reduction to end user electrical consumption based on market or operator feedback. Feedback is typically driven by economic incentives or reliability concerns due to imbalances in supply and demand of electricity. DR is a broad category that can apply to a variety of both consumption technologies (i.e. air conditioner, irrigation, etc.) and customer classes (i.e. industrial, commercial, residential). DR is typically more cost effective with larger individual customer loads. See Figure 5.15 for further details on the DR technologies evaluated.

Figure 5.15 – Demand Response

Operating Characteristics and Estimated Costs	Demand Response
Base Load Net Output (MW)	4.0
Base Project Costs (2015$/kW)	$14.00
Fixed O&M Costs (2015$/kW-year)	$57.07

5.2.5 Renewables Technologies

5.2.5.1 Wind

Three renewable technologies were evaluated in the IRP. Those technologies were wind energy, solar photovoltaic, and hydroelectric.

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 5.16 for further details on the variety of wind technologies evaluated.

Figure 5.16 – Wind Renewables

Operating Characteristics and Estimated Costs	50 MW Wind (Indiana)	200 MW Wind (Indiana)
Base Load Net Output (MW)	50	200
Base Project Costs (2015$/kW)	$1,940	$1,680
Fixed O&M Costs (2015$/kW-year)	$45.00	$42.00

The production tax credit (PTC) is a tax credit per-kilowatt-hour (kWh) for electricity generated by qualified energy resources. The duration of the credit is 10 years after the in-service date for all facilities placed in service after August 8, 2005. The tax credit is $0.015 per kWh in 1993 adjusted by inflation adjustment factor provided by the IRS and rounded to the nearest 0.1 cents. Vectren assumed 1.6% past 2016 IRS values, which was the general inflation used throughout the IRP. The tax credit is phased down by 20 percent per year for wind facilities commencing construction after December 31, 2016. The tax credit reduces from 100 percent for wind facilities commencing construction in 2016 and before, down to 40 percent for wind facilities commencing construction in 2019. See Figure 5.17 below for the percent of production tax credit. For purposes of the IRP, Vectren applied the PTC as if the commence construction was one year prior to the commercial operation date.

Figure 5.17 – Wind Production Tax Credit by Year

Commence Construction (Prior to)	Production Tax Credit (%)
2017	100%
2018	80%
2019	60%
2020	40%

5.2.5.2 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 photovoltaic (PV) technology, which directly converts sunlight to electricity due to the electrical properties of the materials comprising the cell.

Photovoltaic (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 aluminum back-plate on the other. See Figure 5.17 for further details on the solar PV technologies evaluated.

Figure 5.18 – Solar Photovoltaic

Operating Characteristics and Estimated Costs	3 MW Solar PV	6 MW Solar PV	9 MW Solar PV	50 MW Solar PV	100 MW Solar PV
Base Load Net Output (MW)	3	6	9	50	100
Base Project Costs (2015$/kW)	$3,420	$2,700	$2,540	$2,260	$2,230
Fixed O&M Costs (2015$/kW-year)	$19.50	$19.50	$19.50	$19.50	$19.50

As discussed in Section 1.3.8, Solar Generation, the Investment Tax Credit (ITC) is a federal tax credit as a percent of basis invested in eligible properly. Investment tax credit percentage depends on the commencement of construction as shown below in Figure 5.19. For modeling purposes, Vectren assumed commercial operation date and commence construction to be the same year for solar projects. The eligible investment was assumed to be the total invested project costs to build. The Investment Tax Credit was normalized over the book life of the asset, which evenly distributes the tax credit out over the asset book life.

Figure 5.19 – Solar Investment Tax Credit by Year

Commence Construction (Prior to)	Investment Tax Credit (%)
2017	30%
2018	30%
2019	30%
2020	30%
2021	26%
2022	22%
1/1/2022 & beyond	10%

5.2.5.3 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 5.20 for further details on the hydroelectric technology evaluated.

Figure 5.20 – Hydroelectric

Operating Characteristics and Estimated Costs	50 MW Low-head Hydroelectric
Base Load Net Output (MW)	50
Base Project Costs (2015$/kW)	$3,760
Fixed O&M Costs (2015$/kW-year)	$75.00

5.2.5.4 Waste-to-Energy

Two waste-to-energy (WTE) technologies were included within the analysis. Stoker boiler technology, or biomass, is the most commonly used WTE technology. Waste fuel is combusted directly in the same way fossil fuels are consumed in other combustion technologies. The heat resulting from the burning of waste fuel converts water to steam, which then drives a steam turbine generator for the production of electricity. The two fuel types evaluated in the IRP were wood and landfill gas, which are represented in Figure 5.21.

Figure 5.21 – Waste to Energy Technologies

Operating Characteristics and Estimated Costs	Wood Stoker Fired	Landfill Gas IC Engine
Base Load Net Output (MW)	50	5
Base Load Net Heat Rate (HHV Btu/kWh)	13,500	10,500
Base Project Costs (2015$/kW)	$4,720	$4,250
Fixed O&M Costs (2015$/kW-year)	$93.00	$180.00

5.2.5.5 Renewable Cost Curve Discussion

5.2.5.5.1 Solar

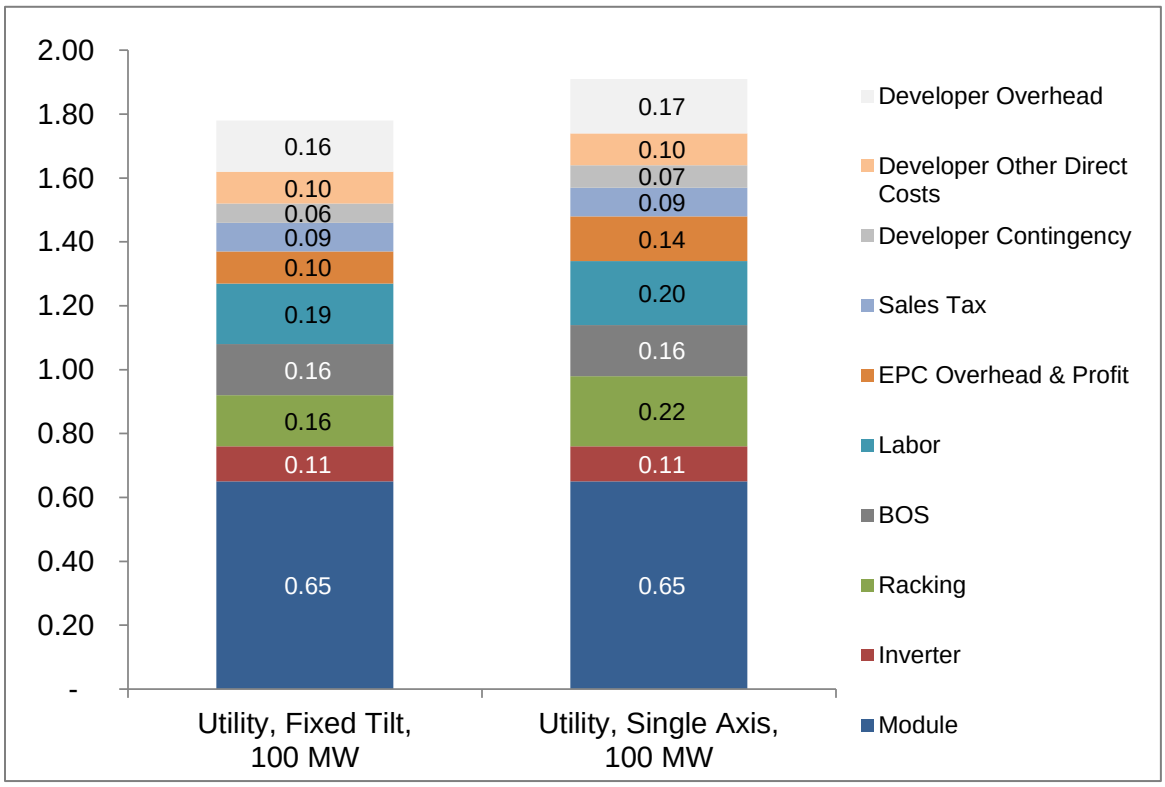
Current overnight capital cost estimates for solar technology were developed by Burns & McDonnell as part of the technology assessment. Pace Global then developed a long-term view of solar capital costs by reviewing public reputable studies and other IRPs. As

a result, Pace Global's estimates are derived from several quality references supplemented with analysis and expert judgment.

In the case of solar photovoltaics (PV), the National Renewable Energy Lab (NREL) provides a rich data set from which to explain current costs and trends. According to NREL, universal solar PV pricing has continued to decline over the last several years. While costs have declined in the past three years, the rate of decline has slowed significantly in the past two to three years as production scale and global competition has driven equipment pricing down[29]. Though some continued improvement in equipment cost is expected, NREL and other experts now expect most cost reductions will come from solar PV project soft costs. Soft costs generally include cost items such as Installation Labor, EPC Overhead & Profit, Developer Contingency, Developer Other Direct Costs, and Developer Overhead. For fixed tilt and single axis systems, soft costs comprise $0.60/Wdc and $0.68/Wdc (dollars per watt direct current), respectively.

[29] Sunshot report - Photovoltaic System Pricing Trends, Historical, Recent, and Near-Term Projections 2015 Edition", DOE Sunshot, Aug 2015, page 19, https://emp.lbl.gov/sites/all/files/pv_system_pricing_trends_presentation_0.pdf

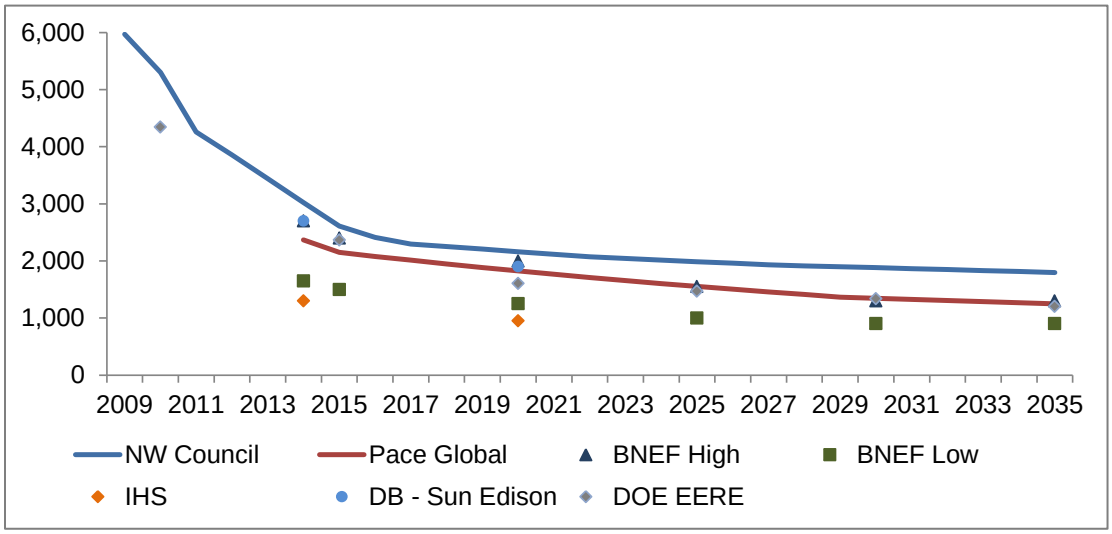
Figure 5.22 – Q1 2015 Universal Solar PV Cost Breakdown, 100 MW U.S. National Average, 2015$/Wdc[30]



To forecast capital cost for solar power generation technology, Pace Global reviewed numerous public sources regarding industry issues, trends, and predictions. Equipment, material, labor, and developer costs were considered to project the rate of cost change. This estimate was then compared with independent forecasts to ensure consistency. Pace Global expects solar capital costs to decline at a compound annual growth rate of 2.7% per year through 2036, which is in-line with other expert forecasts presented in the graph below.

[30] U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential, Commercial, and Utility-Scale Systems; NREL, September 2015

Figure 5.23 – U.S. National Average Overnight Solar PV Capital Costs, 2015$/kW[31]



By combining the 2015 Indiana capital cost estimate with the anticipated decline rate in solar power generation technology costs, a specific forecast for solar PV costs in Indiana is derived.

5.2.5.5.2 Wind

Onshore wind-powered electrical generating technologies are becoming a mature technology. While wind project capital costs are expected to continue declining for several years as wind turbine pricing declines, the rate of decline is expected to slow.

Turbine nameplate capacity, hub height, and rotor diameter have all increased significantly over the long term. Though trends in the average nameplate capacity, hub height, and rotor diameter of turbines have been notable, the growth in the swept area of the rotor has been particularly rapid. All else being equal, increased swept rotor area results in greater energy capture for each watt of rated turbine capacity, meaning that

[31] The sources used to develop the above forecast are as follows: Photovoltaic System Pricing Trends, Historical, Recent, and Near-Term Projections 2015 Edition, DOE Sunshot, Aug 2015; U.S. Solar Market Insight Report, GTM Research and SEIA; Annual Technology Baseline and Standard Scenarios, NREL, July 2015; NW Council 2015 IRP; H1 2015 North American PV Outlook, Bloomberg New Energy Finance 01/16/15; Deutsche Bank, 02/19/15, 02/25/15, 05/04/15, 05/13/15; Solar Market Intelligence, IHS, 07/07/15; WindVision: A New Era for Wind Power in the United States, DOE EERE, Mar 2015; Pace Global client confidential data.

the generator is likely to run closer to or at its rated capacity and more often. The expected growth in capacity factors resulting from improved turbine designs is being held back by curtailments and inter-year wind resource variability. The strength of the wind resource varies from year to year, partly in response to significant persistent weather patterns such as El Niño/La Niña. A relatively strong El Niño in 2015 led to lower than expected wind speeds in the first two quarters, which reduced turbine output.

Based on these trends and observations, Pace Global estimates that 2016 overnight capital costs for an Indiana-based 50 MW wind farm are expected to decline by an average of one percent per year through 2030, with a lower decline rate of 0.3% per year thereafter.[32]

5.2.5.6 Out-of-State Wind

5.2.5.6.1 Contracted Wind Prices

Recent energy trade publications have touted the cheap energy production costs and increased capacity factors (the average power generated, in relation to the rated peak output of the wind turbine) of wind rich areas located in various parts of the MISO footprint, all of which are outside of Indiana. Combined with certain geographic locations being greater in wind output, technological innovation, production tax incentives, and various other factors, the contracted price of wind energy has decreased over time. Based on data from the U.S. Department of Energy, wind output in the plains states of Iowa, Oklahoma, and Kansas yields more megawatt hours and therefore a lower cost per MWh than Indiana wind resources[33]. The differences in cost per MWh are as much

[32] Pace Global used the following sources in developing this capital cost decline curve: 2015 Wind Technologies Market Report, August 2015, EERE; EIA AEO 2016 Assumptions; Lazard Levelized Cost of Generation Study, version 9.0, NOV 17 2015; The Cost Landscape of Solar and Wind, America's Insight, Jan 2015, BNEF; WindVision: A New Era for Wind Power in the United States, DOE EERE, Mar 2015; RE Map 2030, IRENA, May 2015; Most recent IRPs from Entergy Arkansas, NW Power Council, TVA, and Pacificorp.

[33] U.S. Department of Energy, National Renewable Energy Laboratory http://www.c2es.org/technology/factsheet/wind

as $20 and place wind energy from the plains states at prices competitive with conventional electric power generation.

Growth of wind resources moderated in 2015 due in part to the uncertainty regarding the renewal of the federal tax credits. However, in December Congress extended the investment and production tax credits of $23/MWh and allowed for wind resources under construction by 2016 to receive the full credit for the first 10 years of operation. The credit decreases 20 percent per year for units that begin construction each year from 2017 through 2019. Additional wind growth may also occur in the coming years as Multi Value [Transmission] Projects ("MVP") are completed, which include 17 transmission projects with regional benefits expected to significantly exceed the estimated $6.3 billion cost[34].

5.2.5.6.2 Total Cost of Delivered Wind

Aware of this generation shift and growth in wind generation, Vectren has monitored these developments and researched the current total cost of delivered wind. The total cost of delivered wind, as with any generation, that is accredited towards Vectren's planning reserve margin is comprised of three main factors: the cost of energy (the wind itself), the cost of delivering the energy (through transmission lines), and any transmission congestion charges (charges that are added to the energy component as a result of overloads on the system). In addition to cost consideration, other factors include timing, certainty, and access.

5.2.5.6.3 Delivering the Wind

Vectren has three options for delivered wind to serve load: 1) build a transmission line, 2) pay for use of existing MISO transmission through tariff rates, or 3) contract for

[34] 2015 State of the Market Report for the MISO Electricity Markets, By Potomac Economics, June 2016 https://www.misoenergy.org/Library/Repository/Report/IMM/2015%20State%20of%20the%20Market%20Report.pdf

subscriber-based transmission projects that charge a per MW rate for capacity (usage) of the line.

Building a specific transmission line for the sole purpose of delivering wind to Vectren load is an option that presents several challenges. The most obvious hurdle is cost. The cost of building high-voltage (138 kV and above) transmission to transport wind from the turbine to its desired load ranges from $1 million to $3 million per mile. For reference, MISO's most recent Market Efficiency [Transmission] Project "Duff to Coleman" is a 345 kV single circuit line that MISO has estimated to cost approximately $2,104,209 per mile[35]. Wind that would be accredited to Vectren load would have to be connected from the turbine to a MISO load zone. Wind located within Iowa, for example, would require less mileage to connect since Iowa is located within MISO, while wind in Kansas would require considerable spans of transmission to connect to MISO. In addition to the cost of connecting wind into MISO via constructing a new line, there is the coordination and increased requirements dictated by the system in which the wind generator is physically located. This would include additional study costs and possible upgrades to that system's transmission facilities. Building a transmission line to deliver wind would only be viable if the wind is located within or near a MISO load zone.

Part of the benefit of being a member of MISO is the open access it provides to MISO transmission and the avoidance of pancaking, paying a separate rate to each transmission owner to pass energy through its line, of transmission rates. Wind that is connected to existing MISO transmission would pay defined tariff rates for usage of the path. These tariff rates vary for each Load Serving Entity (LSE), but in most instances for Vectren, add $1-$5 of cost per MWh. However, before a generator can tie-in to the MISO system, a System Impact Study (SIS) must be performed that will analyze the impact that generator will have on the entire system and identify any transmission

[35] MISO 2015 MEP Bid Summary
https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2015/20150729/20150729%20PAC%20Item%2004%20Duff%20Coleman%20Project%20Estimate.pdf

upgrades needed as result of the additional generation onto the system. This cost is borne solely by the generator. The timing for the study results is approximately 12-18 months, and the cost is between $60,000 and $600,000 depending on the size of the unit.

The final option is subscribing to a transmission project and paying for transmission "capacity", or defined usage of the line, to deliver wind. The predominant subscriber-based developer of transmission lines in North America is Clean Line Energy, which currently has three proposed transmission projects that would bring wind from the west into the Midwest region. One of those projects, Grain Belt Express, would bring upwards of 3,500 MWs of wind into Sullivan, IN. This project would source wind energy from southwest Kansas, which has some of the highest capacity factor (the average power generated, in relation to the rated peak output of the wind turbine) wind in North America. All three of the projects are dependent upon a sufficient amount of subscribers to economically justify the construction of the lines and the regulatory approval process for the lines to traverse multi-state regions.

The Grain Belt Express transmission project has been delayed while Clean Line Energy Partners, the developer of the project, seeks regulatory approval from the Missouri Public Service Commission (MPSC). The MPSC has been the lone state to deny the approval of the project. Clean Line filed its third application with the MPSC on September 5, 2016. Representatives of the Block Grain Belt Express, the grass-roots organization that led to the project's rejection last summer, remain in opposition of the project as it cites health concerns and reductions in financial benefit as the main deterrents. The construction and right-of-way acquisition timeline could take 5-7 years if the MPSC approves the project.

5.2.5.6.4 Congestion Charges

Transmission congestion charges are the final element for consideration when analyzing the true cost of delivered wind and are the most difficult to estimate.

Congestion charges are calculated by taking the difference in Locational Marginal Pricing (LMP's) where the energy is injected (source) and where the energy is withdrawn (sink). For Vectren to purchase wind outside of Zone 6 (Indiana), Vectren 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 wind. 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 considering the cost of wind, the required transmission charges, and estimated congestion charges based on historical data, the greater the distance, the greater the potential for higher costs.

5.2.5.6.5 Analysis

MISO's current transmission system is not designed to support a large influx of variable resources, such as wind, and is undergoing a paradigm shift that involves further build-out of its system to accommodate the unique properties of wind. Currently during periods of high wind, MISO has to curtail individual wind units due to overloading of the MISO transmission system.

While wind resources account for less than 10% of both energy and capacity within MISO, they still set negative LMPs in the local areas they are located in almost half of the time. A negative LMP means that MISO must be paid for each MWh put on the grid. Typically MISO pays producers to put power on the MISO grid. Negative LMPs are intended to signal generators that their power is not needed. This is due to the frequent curtailment of wind generation to manage congestion. As wind continues to increase its makeup of MISO capacity, additional transmission build-out may be needed to deliver the wind from wind rich areas to large load bases[36].

[36] MISO's Analysis of EPA's Final Clean Power Plan Study – June 2016 page 6
https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2016/20160615/20160615%20PAC%20Item%2002a%20MISO's%20Analysis%20of%20EPA's%20Final%20Clean%20Power%20Plan%20Study%20Report%20Draft%202_Highlighted%20Changes.pdf

Additionally, although wind is more than 9% of MISO's installed capacity (ICAP), it is less than 2% of MISO's unforced capacity (UCAP), which means that for planning purposes, its capacity credit is approximately 15% of its stated generation capability and can only be relied upon for that amount. For the 2016-2017 planning year, MISO's system-wide wind capacity credit is 15.6%[37]. Wind located in MISO's Zone 1 (Montana, North Dakota, South Dakota, Wisconsin, and Michigan) receives a UCAP value, or Effective Load Carrying Capability (ELCC) of 18.8% of installed capacity, while wind in Zone 6 (Indiana and Kentucky) receives virtually half that amount at an estimated 9.6%. Essentially, utilities in Zone 6 only get to approximately 10 MW out of every 100 MW, depending on location and performance, to meet the MISO's planning reserve margin requirement. This calculation is based mainly on historical output of each wind resource, while also considering the wind resource's location. Given the uncertainty around out-of-state wind costs, Vectren utilized an estimate of in-state wind for this analysis. As projections of out-of-state wind costs become more certain, Vectren will re-evaluate out-of-state wind in future IRPs.

5.2.6 Energy Storage

Two energy storage technologies were evaluated in the IRP –batteries and compressed air energy storage (CAES). These are shown in Figure 5.24.

Batteries utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging, and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity, ease of installation and operation, and relative design maturity.

To utilize CAES, a suitable storage site is needed, either above or below ground, as well as availability of transmission and fuel source. CAES facilities use electricity to

[37] MISO's Planning Year 2016-2017 Wind Capacity Credit Report – December 2015
https://www.misoenergy.org/Library/Repository/Report/2016%20Wind%20Capacity%20Report.pdf

power a compressor train that compresses air into an underground reservoir at approximately 850 pounds per square inch (psig). Energy is then recaptured by releasing the compressed air, heating it (typically) with natural gas firing, and generating power as the heated air travels through an expander. The expander is essentially a turbine that spins as the compressed air is released from storage.

Both battery and CAES technology offer a way of storing low-priced, off-peak generation that can be discharged during higher-priced, peak demand hours.

Figure 5.24 – Energy Storage Technologies

Operating Characteristics and Estimated Costs	Lithium Ion 10 MW / 40 MWh	Lithium Ion 1 MW / 1 MWh	Commercial 100 kW / 250 kWh	Residential 2 kW / 7 kWh	CAES
Base Load Net Output (MW)	10	1	0.1	0.002	100
Round-Trip Cycle Efficiency	90%	90%	90%	90%	75%
Base Project Costs (2015$/kW)	$3,050	$2,430	$3,080	$3,480	$1,490
Fixed O&M Costs (2015$/kW-year)	$16.20	$40.80	$50.40	$60.00	$7.00

5.2.6.1 Energy Storage Cost Curve Discussion

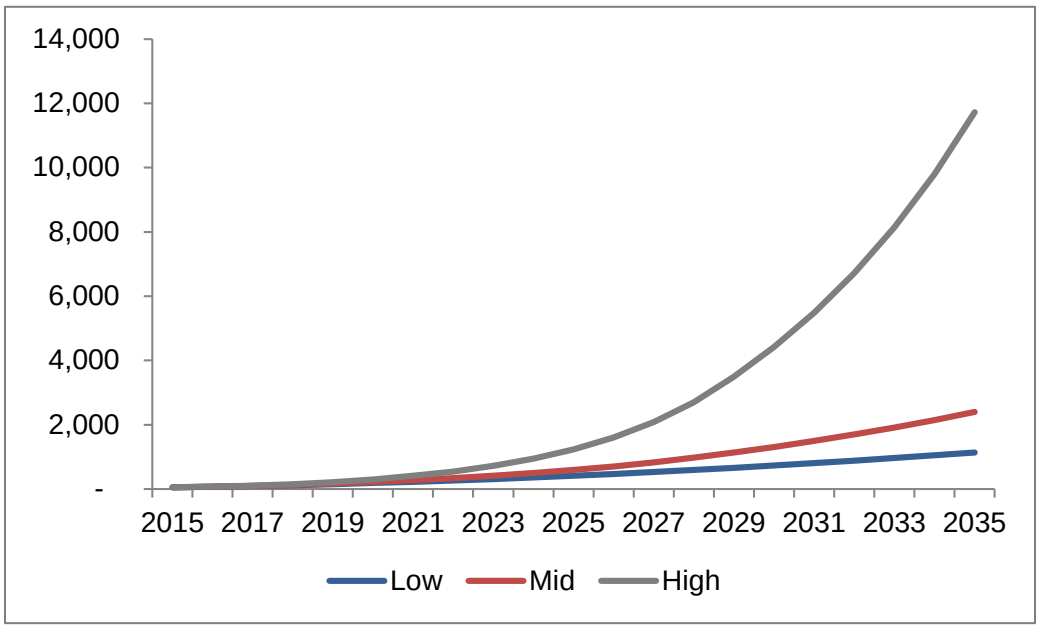
Current overnight capital cost estimates for battery technologies (residential, commercial, and universal) were developed by Burns & McDonnell as part of the technology assessment. Pace Global then developed a long-term view of battery capital costs by class from the expected volumetric growth in lithium-ion battery sales for automotive and grid support applications and anticipated technology learning rates. Data supporting this analysis was sourced from public independent expert studies and available IRPs. The approach is tried and tested, frequently applied during the early stages of new technology adoption to estimate demand and pricing when measured market data is limited.

A single deterministic price forecast may introduce bias that skews the forecast path. To counter this, Pace Global sought to develop a reasonable range of price expectations to support the stochastic market analysis. The selected approach is founded on the principle that as greater numbers of similar sizes and types of batteries are manufactured, economies of scale and learning effects from manufacturing engineers will result in reduced unit production costs. Such a belief is well-supported in literature.

Pace Global developed a forecasted range of lithium-ion battery sales for similar applications, specifically automotive and grid support, but not consumer electronics. A June 2015 report to the National Renewable Energy Lab (NREL)[38] provided a forecast of demand for lithium-ion batteries used in several applications, as well as forecast growth rates from several leading experts[39] ranging from 22% to 41% through 2020. By combining these outlooks, several lithium-ion battery sales forecasts were derived for the period 2016-2036.

[38] Automotive Lithium-ion Battery (LIB) Supply Chain and U.S. Competitiveness Considerations, Clean Energy Manufacturing Analysis Center, June 2015
[39] Roland Berger, Navigant Consulting, AAB, Avicenne, and CEMAC

Figure 5.25 – Global Lithium-Ion Battery Sales Forecast, Automotive & Grid Applications, 2015-2036 GWh



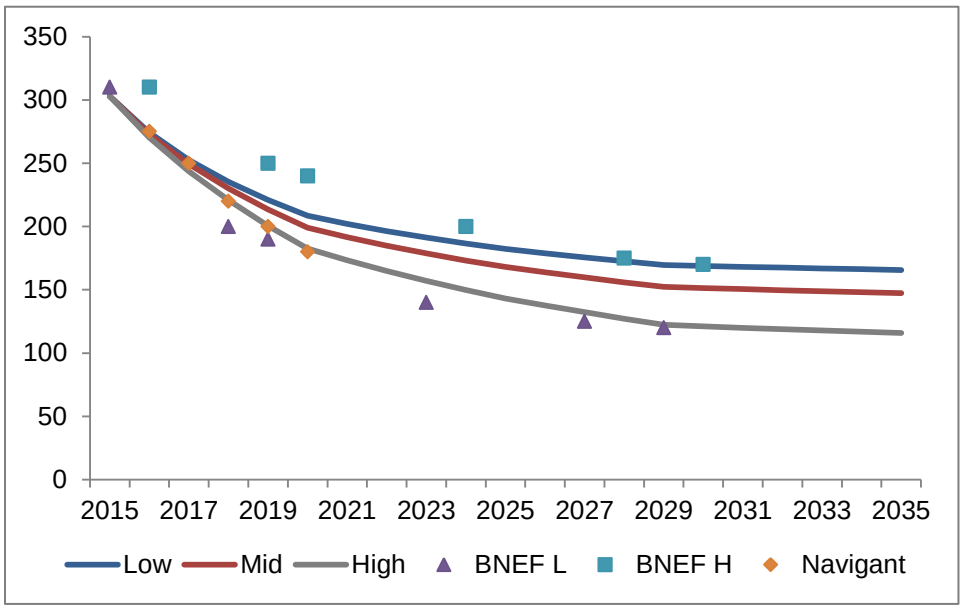
Pace Global then researched publically available literature to determine recently reported progress and learning rates for lithium-ion battery development and other power generation technologies. A nonlinear learning function and a progress ratio formula are developed to estimate the speed of learning (i.e. how much costs decline for every doubling of capacity). To apply this approach, three large format lithium-ion battery sales growth and learning development scenarios were developed with growth rates applied in each of four stages of market development. This resulted in three unique sales forecasts to which the aforementioned learning model was applied. Four different learning rates were developed to align with the four stages of market and technology development. When applied, three independent lithium-ion battery price paths were estimated based on market growth and learning expectations. The results of these derivations were compared with other publically available projections[40,41] to

[40] Bloomberg New Energy Finance Summit 2015, April 2015

41 The Lithium Ion Battery Market, Navigant, Jan 2014

assess the reasonableness of the results. The results and comparison against other available sources are presented in the graph below[42].

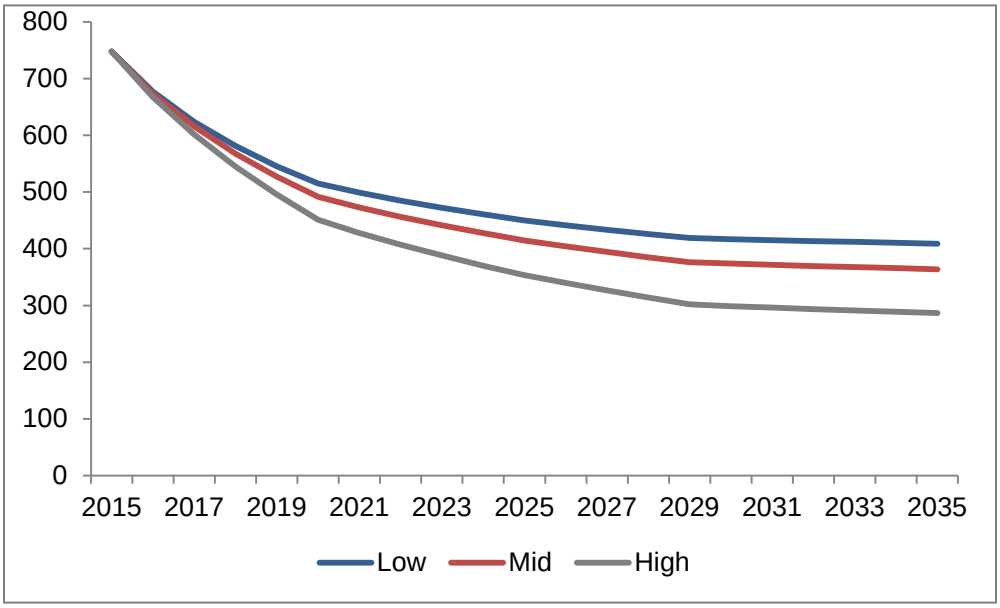
Figure 5.26 – Lithium-Ion Battery Storage Cost, $kWh



A lithium-ion battery-based bulk energy storage system requires more than batteries to deliver energy to the grid on demand. To estimate the overnight cost of the battery storage system, Pace Global estimated the additional balance of plant costs that a utility would require to complete the system. To finalize the all-in cost estimate, a financing charge (IDC/AFUDC) appropriate to the expected loan was added. The all-in utility scale lithium-ion battery storage cost estimates for the different market growth and learning expectations are displayed in the graph below.

[42] The sources used to develop the above forecast are as follows: The Cost Landscape of Solar and Wind, America's Insight, Jan 2015, BNEF; Bloomberg New Energy Finance Summit 2015, New York, April 2015; Energy Storage, EV's and the Grid, Tesla Motors, 2015 EIA Conference, June 15, 2015; Batteries Charge Up For the Electric Grid, Moody's, 24 SEPTEMBER 2015; The Economics of Load Defection, Rocky Mountain Institute, April 2015; U.S. Electric Utilities & IPPs, Storage Deep Dive Highlights Supply Chain Risks, 18 September 2015; Batteries and Energy Storage, NY Battery and Energy Storage, June 2015; Lazard's Levelized Cost of Storage Analysis – Version 1.0, November 2015; U.S. Energy Storage Monitor, Q1 2015, May 2015, GTM Research; Pace Global proprietary Li-ion production cost model; Pace Global client confidential data.

Figure 5.27 – All-In Utility Scale Lithium-Ion Battery Storage Cost, $/kWh



5.3 MISO CAPACITY CREDIT

Each resource option receives varying amounts of capacity credit within MISO based on their ability to reliably contribute capacity at the peak demand hour. Combined cycle gas turbines are considered base load (24/7 power) and can produce an expected level of output when called upon. For this reason, utilities are able to count nearly the full installed capacity for CCGTs (less their historical outage rate). A new combined cycle facility can count 96 MWs out of every 100 MWs of installed capacity towards meeting the MISO's planning reserve margin requirement. 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. Neither wind nor solar resources tend to reliably provide their full installed capacity at the peak demand hour, as such, they receive less capacity credit.

Typically, renewable wind resources do not produce much energy during hot summer days when Vectren normally sees peak demand. Vectren's receives approximately 11% capacity credit towards meeting planning reserve margin for its wind resources.

While renewable wind resources produce a lot of renewable energy, they cannot be counted on for capacity. A solar power plant in Southern Indiana is expected to receive 38% capacity credit. For every 100 MW of installed capacity, Vectren would receive 38 MWs of capacity credit from MISO. The tradeoff between renewable wind and solar resources is energy need vs capacity need. Within optimization modeling, solar tends to be selected as a resource before wind when there is a capacity need.

Figure 5.28 – MISO Capacity Credit

Accredited Capacity	CCGT	GT	Wind[43]	Solar[44]
% of Summer output	96%	76-94%	11%	38%

5.4 TRANSMISSION CONSIDERATIONS

5.4.1 Description of Existing Transmission System

Vectren's transmission system is comprised of 64 miles of 345 kV lines, 374 miles of 138 kV lines and 565 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 (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, a 345 kV interconnection to Big Rivers' Reid EHV Substation, a 138 kV interconnection at IPL's Petersburg Generation Station, and 138 kV interconnections to Hoosier Energy, LGE/KU, and Big Rivers at Vectren's Newtonville Substation.

[43] For wind, 11.25% (based on actual performance of Benton County and Fowler Ridge units) was used to calculate the amount of UCAP available for modeling.
[44] For solar PV, 38% was used to calculate the amount of UCAP available. This number closely aligns with the PJM capacity credit for solar and NREL expectations for the Vectren service territory.

5.4.2 Discussion on Resources Outside of Area

As mentioned above, Vectren'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 900 MWs (or approximately 75% of peak demand). Although Vectren 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)

5.4.3 Evaluation of Various Resource Configurations as an Input to the Optimization Model

Vectren performed an analysis of its transmission system's performance in an effort to understand the high-level impact of building a combined cycle gas turbine plant to replace the existing AB Brown 1 and 2 coal units. Transmission enhancement cost estimates were developed for this scenario and used as an input to the optimization model.

The following outlines the basic assumptions used in this analysis:

Figure 5.29 – Transmission Input Analysis Assumptions

Generator Retirements:	**Vectren Generators Available:**
Culley Unit 2 – 90 MW	AB Brown Unit 3 – 80 MW
BAGS Unit 1 – 60 MW	AB Brown Unit 4 – 70 MW
Northeast Units 1 and 2 – 20 MW	BAGS Unit 2 – 60 MW
Warrick Unit 4 - 300 MW[45]	New AB Brown CC ST – 422 MW
	New AB Brown CC CT – 211 MW
	New AB Brown CC CT – 211 MW
	Culley 3 – 270 MW
Generator Modeling Notes: Coal unit retirements occur at the end of 2023. On January 1, 2024, a new 844 MW[46] A.B. Brown combined cycle adds two new 211 MW combustion turbines and a 422 MW steam turbine (output based on summer temperature of 90F).	

In this scenario, west to east power transfer becomes an issue due to the increased output of the AB Brown plant. This problem would be magnified should ALCOA-Warrick generating facility (units 1-4) shut down. Additionally, voltage performs poorly on the east side of the transmission system due to the loss of reactive power support from the Warrick power plant.

Several projects were modeled to mitigate the west to east power transfer issue. A new 138 kV line from the AB Brown power plant to Pigeon Creek substation to the Culley power plant along with miscellaneous 69 kV upgrades mitigated all of the issues. In order to provide sufficient reactive support, a synchronous condenser was modeled. The estimated cost for these projects is listed below.

[45] There is still uncertainty with respect to the ALCOA-Warrick generation facility following the retirement of ALCOA's aluminum smelter. A conservative planning approach was taken in this analysis and all four Warrick generating units were modeled as retired with Vectren serving the remaining ALCOA load.
[46] 889 MW is expected output at 59 degrees (average annual temperature)

Figure 5.30 – Estimated Cost of Transmission Modeling Input

New 138 kV Line	$31,840,000[47]
138 kV Terminal Upgrades	$1,150,000
138 kV Terminal Relocation	$250,000
Misc. 69 kV Upgrades	$2,179,500
Synchronous Condenser Conversion	$6,000,000
Total	**$41,419,500**

Cost Estimate Notes:

- The cost for the 138 kV line was based on 12 miles through suburban terrain ($800k per mile), followed by 12 miles double circuited with a 69 kV line through Evansville metro ($1,000k per mile), and then followed by 12.8 miles through suburban terrain ($800k per mile). The distances are based on a preliminary route developed by Vectren transmission engineering.
- The 138 kV terminals were based on estimates of $150k per breaker (one installed at AB Brown, two at Pigeon Creek, and two at Culley) plus $100k per dead-end terminal (four total). These costs are based on actual costs from several recent projects.
- The $250k for the terminal relocation is for AB Brown. There is an open bay for a new 138 kV terminal; however, it shares a common breaker with Z93 AB Brown – Northwest. A fault on this breaker outages both the new line and Z93, causing an overload on Z99 AB Brown – Northwest. Z93, Z99, and the new line need to be on different rungs to prevent a breaker fault overloads. The cost for this was based on a recent project to relocate 138 kV line terminals at another substation, escalated due to the more complex nature of this relocation. Also, this cost is a high-level budget number because the design for this relocation has the potential to be very complex and there are currently too many unknowns.
- The 69 kV upgrades include 1.83 miles of conductor upgrade through Evansville metro ($650k per mile), 12 switches to be replaced ($37k each), and 0.21 miles of underground conductor to be replaced ($2,600k per mile).

[47] Vectren engaged a third-party consultant to verify the cost estimate for the new 138 kV line. The third-party estimate was approximately $37M, or $6M higher than the original cost estimate.

- A synchronous condenser was modeled to provide reactive support, with a cost provided by GE. However, it is possible that an SVC or STATCOM device would also provide sufficient support. These devices could be studied more in depth if this scenario moves forward.

5.5 BUSBAR SCREENING

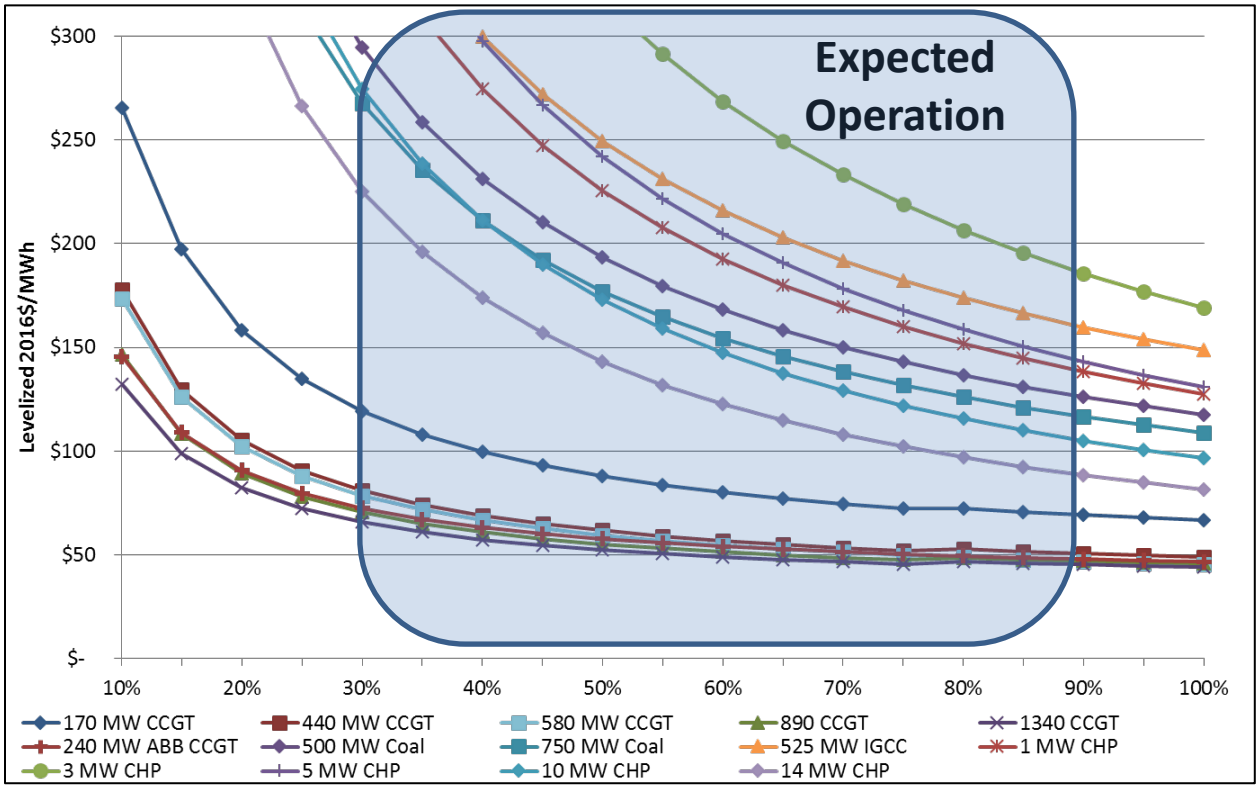
Vectren considered a wide variety of power supply alternatives including 24/7 baseload, intermediate, and peaking options, as well as renewable generation, energy storage, distributed generation, and demand side management. These power supply alternatives were screened using a busbar levelized cost of electricity analysis. Levelized cost of electricity is the net present value of costs to install and operate an energy system divided by its expected energy output over a defined time period. The busbar analysis was done in order to reduce the number of alternatives that would be simultaneously evaluated within Strategist, the planning model.

The screening analysis was performed by developing and comparing the levelized cost of electricity for each resource over the same 20 year period. This simple approach is used to identify and limit the number of higher-cost generation alternatives that would otherwise be expected to operate in a similar nature to lower-cost alternatives. For screening purposes, estimated costs included emissions (CO_2), fuel, operation & maintenance, and capital costs. Resources were then compared across various capacity factors in order to compare resource costs across all dispatch levels. Variable resources were compared at their respective output levels.

Using the calculated busbar levelized cost of electricity analysis, technology alternatives were screened for Strategist optimization modeling based on: cost effectiveness, feasibility, and capacity size. The alternatives screened using the busbar levelized cost of electricity calculations are shown in Figure 5.31. Note that in the following Figures 5.31-5.32 the x axis is capacity factor and the y axis is Levelized 2016 $/MWh.

Demand side management (DSM) was not considered in the busbar analysis, but was included as one of the alternatives within the IRP modeling.

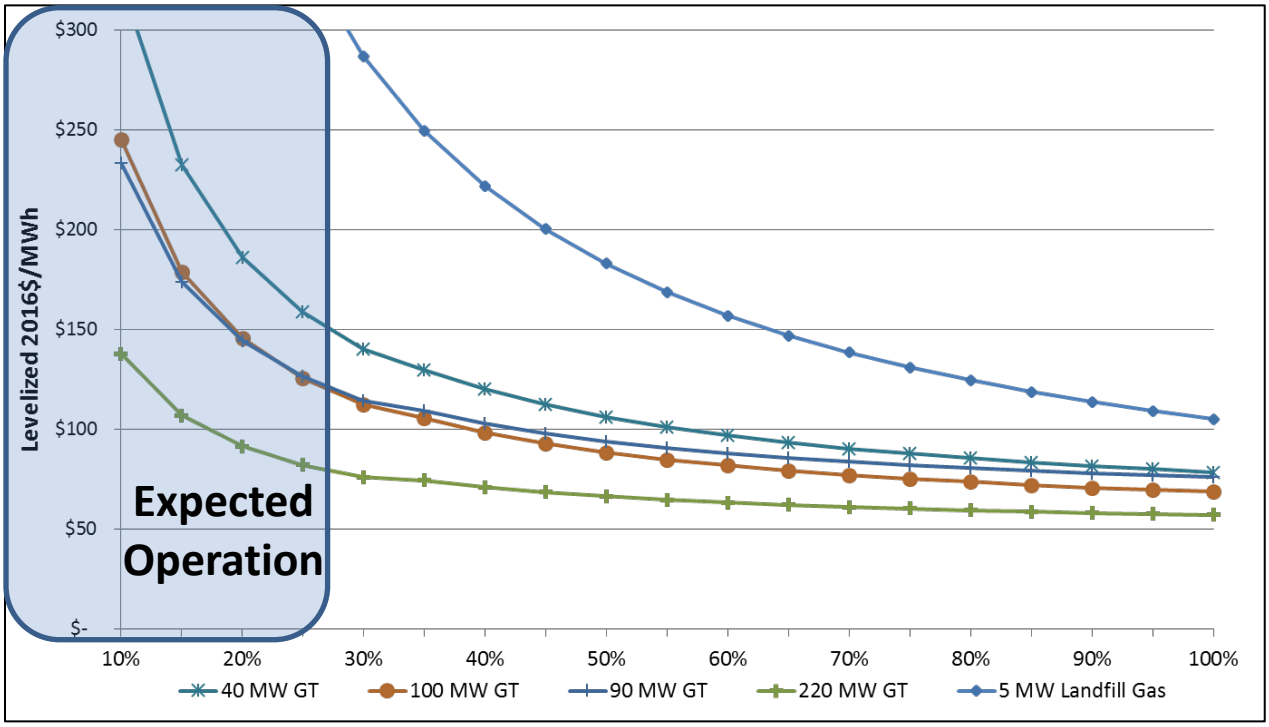
Figure 5.31 – 20-Year Levelized Cost of Electricity: Base and Intermediate Load Resources



The F-class combined cycle gas turbines show the lowest levelized busbar cost across all capacity factors. Due to 3x1 7FA.05 (1,340 MW) exceeding Vectren's forecasted planning reserve margin requirements, this alternative was eliminated from further analysis. Based on the screening results of the base and intermediate resources, the 1x1 7FA.05 (440 MW), 2x1 7FA.04 (750 MW), and 2x1 7FA.05 (890 MW) combined cycles were considered for further analysis within Strategist.

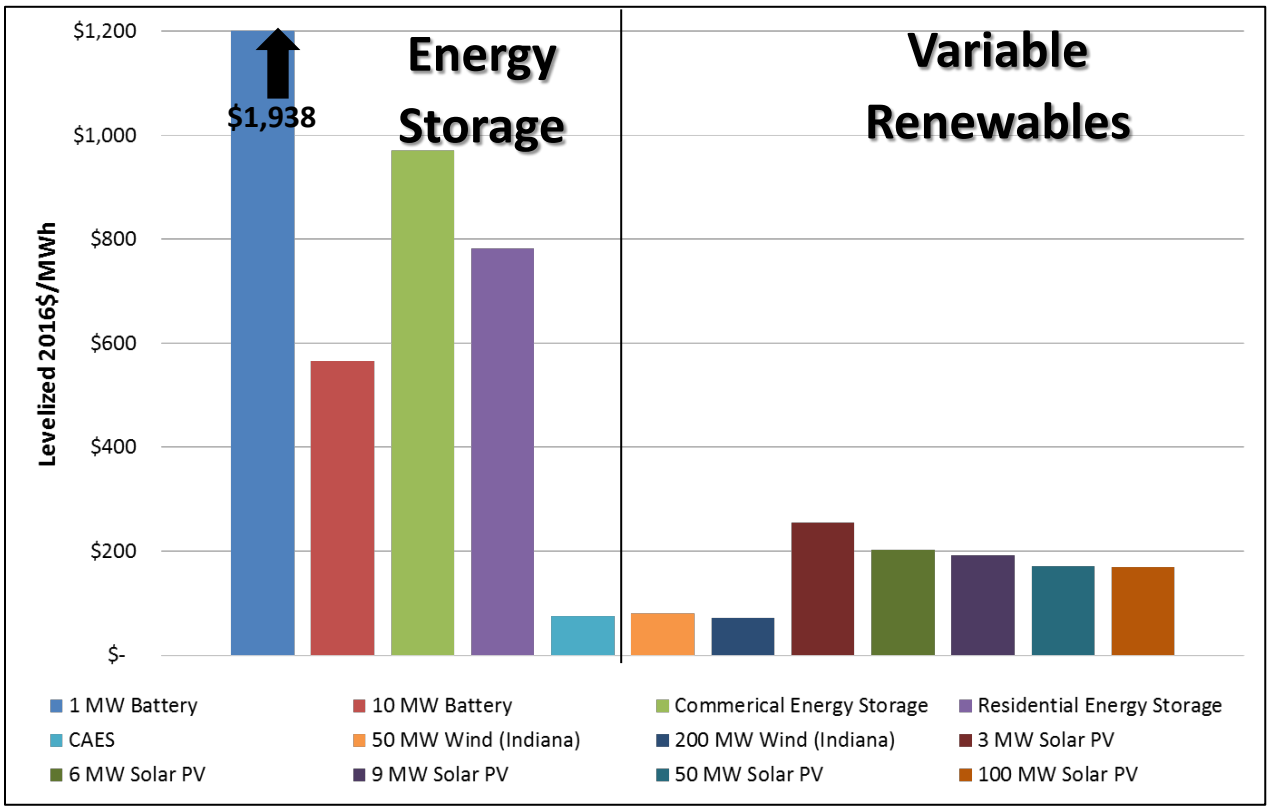
For combined heat and power, the 14 MW option was the lowest cost option evaluated. The 14 MW CHP was included in the Strategist modeling due to the size flexibility and being the most economical CHP option considered.

Figure 5.32 – 20-Year Levelized Cost of Electricity: Peaking Load Resources



The F-class simple cycle gas turbines show the lowest levelized busbar cost across all capacity factors. Due to the smaller project size available with the LMS100 (100 MW), this presented a smaller simple cycle option. The F-Class SCGT (220 MW) and LMS100 (100 MW) technologies were considered for further analysis within Strategist.

Figure 5.33 – 20-Year Levelized Cost of Electricity: Energy Storage & Renewable Load Resources



Two types of renewable resources were included in the final integration analysis. The renewable resources were modeled in various size blocks to be evaluated against the other new construction alternative options. The renewable technologies that were selected by the busbar cost analysis included wind and solar photovoltaic (PV).

Compressed air energy storage was the lowest cost storage option, but was eliminated due to limited feasibility (likely not available) in Vectren's service territory. Suitable underground storage would need to be identified. The 10 MW/40 MWh Lithium Ion represented the next lowest cost storage. Based on the levelized cost of electricity results, the 10 MW/40 MWh battery was carried forward as an alternative in Strategist for the high tech scenario.

SECTION 6
SCENARIOS: OPTIMIZATION MODEL INPUTS & ASSUMPTIONS

6.1 BASE CASE

Vectren developed a base case forecast of key market drivers as inputs into this IRP process that collectively represent the expected path most likely to occur. For many of these assumptions, including natural gas prices, coal prices, and carbon prices, a wide range of views were incorporated into a consensus forecast. For load growth, Vectren developed a bottom-up, forward looking view that incorporates energy, customers, prices, economic drivers, appliance saturation and efficiency, long-term weather, customer owned generation, hourly system load, and 10-year average peak-day weather. The following sections detail these base case assumptions.

The base case scenario is a consensus forecast. Hence, it is impossible to describe specifics regarding the assumptions driving the forecast. However, the base 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 and drivers that lead to moderate market price increases over time. Power market participants under base case conditions are able to adapt and adjust in a timely manner to changing market forces.

Short Term: In the short-term (2016-2018), the base case generally assumes positive sales growth as the economy continues to improve and as Vectren adds new customers to its base. Residential customer growth remains positive, albeit lower, than pre-recession levels, but this is partially offset by moderately declining average use per customer. Similarly, the customer base for small and large commercial and industrial (C&I) customers continues to grow, but with a partial offset of this growth by increasing efficiency. As a result, energy sales grow at a moderate pace.

Natural gas prices remain low through 2016 and 2017 as the current oversupply situation continues to dominate gas market dynamics. However, low prices eventually result in restricted production and reduced gas supply. Coupled with new LNG export terminals and new heavy industrial facilities, demand rises and gas markets begin to

tighten. This is especially true in the premium Gulf Coast market, where much of the demand is materializing, pushing prices incrementally higher in 2018 and beyond. Gas prices in the Utica/Marcellus also recover in 2018 and 2019 as several pipeline projects that provide takeaway capacity enter into service.

Meanwhile, coal prices remain depressed in the near short-term as domestic markets remain soft, with a modest price recovery beginning in 2018.

Market power prices for residential and commercial customers historically have declined since the 2008 recession, but both are expected to experience slight upward price increases over the next few years, based on rising future operating costs and associated revenue requirements. Increased revenue requirements are due to rising replacement and retrofit costs imposed by EPA's ELG regulation as well as by declining reserve margins that compel new builds. Capital costs are generally expected to increase at a moderate pace, reflecting increased costs for labor as the unemployment rate remains at a relatively competitive five percent and higher borrowing costs from rising interest rates, but tempered by lower costs for material as commodity prices remain broadly lower.

Coal plant retirements were high in 2015 driven by regulation including MATS, but continue at a comparatively much more moderate pace in the next few years. Meanwhile, capacity additions in the form of efficient combined cycle gas turbine plants continues at a healthy pace as merchant plants and utilities continue to take advantage of actual and expected low gas prices.

Medium Term: In the medium-term (2019-2025), the base case consensus forecast reflects the assumption that most states, including Indiana, will opt for a mass-based Clean Power Plan (CPP) compliance approach due to the expected broader trading opportunities, albeit with a two year delay of the beginning of the compliance period (from 2022 to 2024) due to the legal uncertainty following the U.S. Supreme Court stay.

Mass-based is seen as a more optimal compliance approach for coal heavy states relative to the rate-based approach alternative. Specifically:

- It is considered simpler and easier to administer than a rate-based plan.
- Retirements of older inefficient plants that are occurring primarily due to economics.
- States will feel pressure to join together to create the most liquid market and largest possible pool of trading partners for emissions reductions.

In the medium-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 to grow at a moderate pace, driven by new C&I customers locating in the Midwest to take advantage of access to low-cost shale gas.

Natural gas prices at the Henry Hub do increase to $4/MMBtu and above as markets tighten significantly on the Gulf Coast. Midwest gas prices continue to benefit from proximity to the Utica and Marcellus shale plays, helping to keep regional gas price growth to a more moderate level.

Coal prices recover most strongly in the Illinois Basin to 2020, with a modest recovery in the Powder River Basin and very limited recovery in the Appalachian region, due to consolidation among producers, lowered production that tightens supply, and a modest export market.

CO_2 prices in California and in Northeast states participating in RGGI harmonize with the broader U.S. market as the CPP compliance period begins in 2024. Given that the CPP allows for interim goals for compliance, CO_2 prices are expected to increase moderately as states adapt to the compliance regime and carbon markets have time to adjust.

Market power prices continue to move upward moderately as the CPP compliance period begins. Fuel costs increase incrementally with new export demand markets. As 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 make improvements and the unemployment rate remains around five percent, capital costs rise as competitive upward pressure remains on labor costs.

Coal-plant retirements mean no emissions from retired plants, which contribute to lowering total emissions under a mass-based approach. Through the years after the CPP goes into effect in 2024, coal plant retirements will continue to be driven by plant-specific going-forward economics. Meanwhile, capacity additions largely come from natural gas combined cycle turbines, solar, and wind facilities.

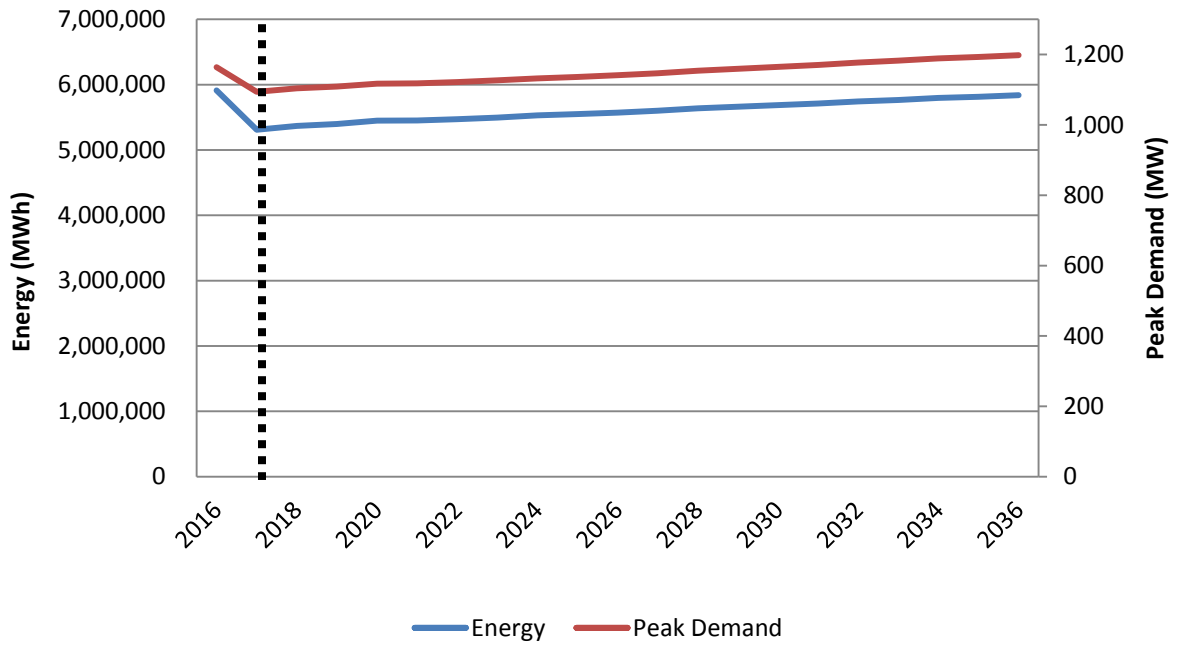
Long Term: In the long-term (2026-2036), the suite of market outcomes and drivers in the base case settles into a pattern of moderate growth based on a well-balanced market. Markets have sufficient time to adapt and adjust as the final CPP goal in 2030 nears and as regulation is expected to be extended to 2036 and beyond, helping keep CO_2 prices reasonable if growing. Energy demand grows as electric car sales take hold but is offset by continued gains in distributed generation and energy efficiency measures. Domestic shale gas and coal resources help to keep fuel cost growth to a moderate level. Capital costs increase at a measured pace as the GDP growth rate averages two percent or more. Capacity additions and retirements continue at a reasonable rate as the fleet of power plants maintains a healthy rate of turnover.

6.1.1 Input Forecasts

The long-term energy and demand forecast for the Vectren service territory was developed for Vectren by Itron. For more information, please see Section 4 Customer Energy Needs. The forecast is based on a combination of historical usage trends and a bottoms-up approach to drivers such as residential and commercial demand, industrial

load, appliance saturation, energy efficiency, long-term weather trends, customer-owned generation, and an outlook for economic factors.

Figure 6.1 – Base Case Vectren Load Forecast (MWh and MW)



For natural gas, coal, and carbon, Vectren used a "consensus" base case view of expected prices by averaging forecasts from several sources. For natural gas, forecasts from Ventyx, Wood Mackenzie, EVA, and PIRA were averaged. For carbon, forecasts from Pace Global, PIRA, and Wood Mackenzie were averaged. This helps to ensure that reliance on one forecast or forecaster does not occur.

Figure 6.2 – Base Case Natural Gas Price Forecast (2015$/MMBtu)

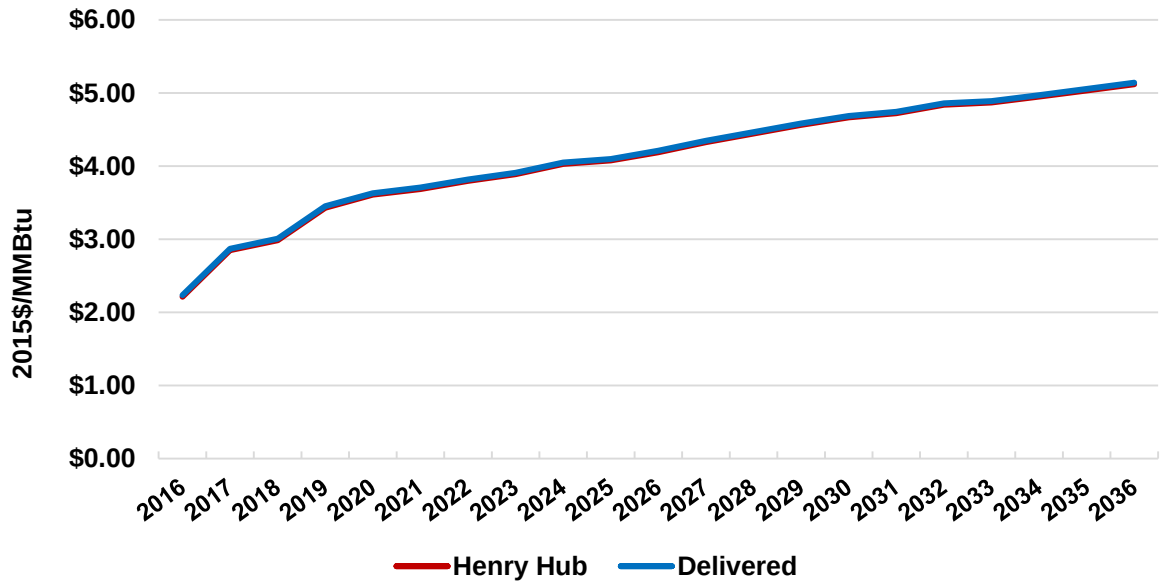


Figure 6.3 – Base Case Coal Price Forecast (2015$/MMBtu)

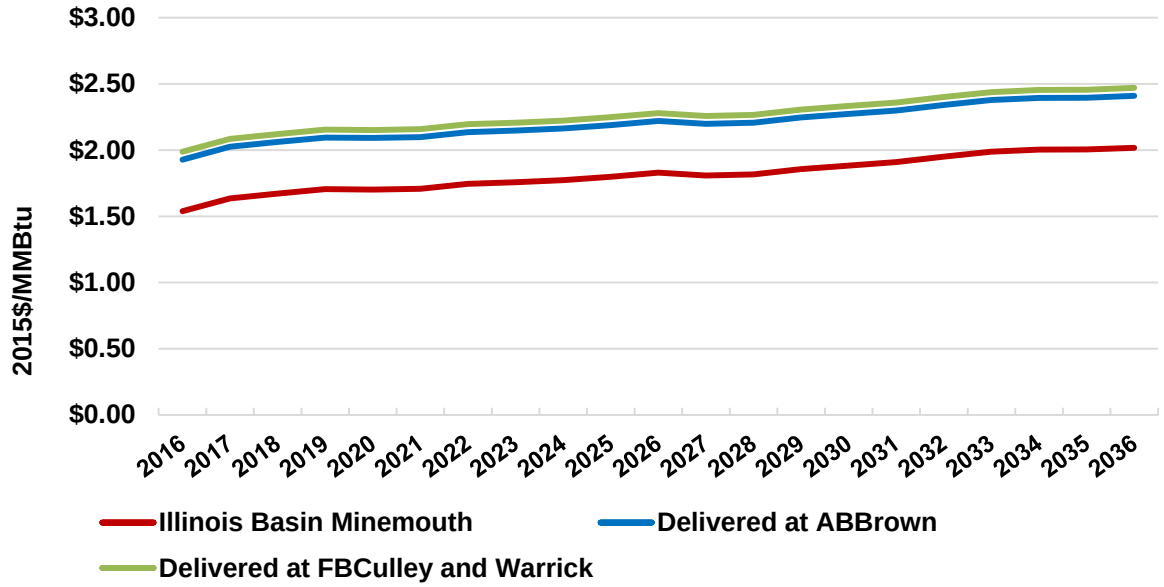
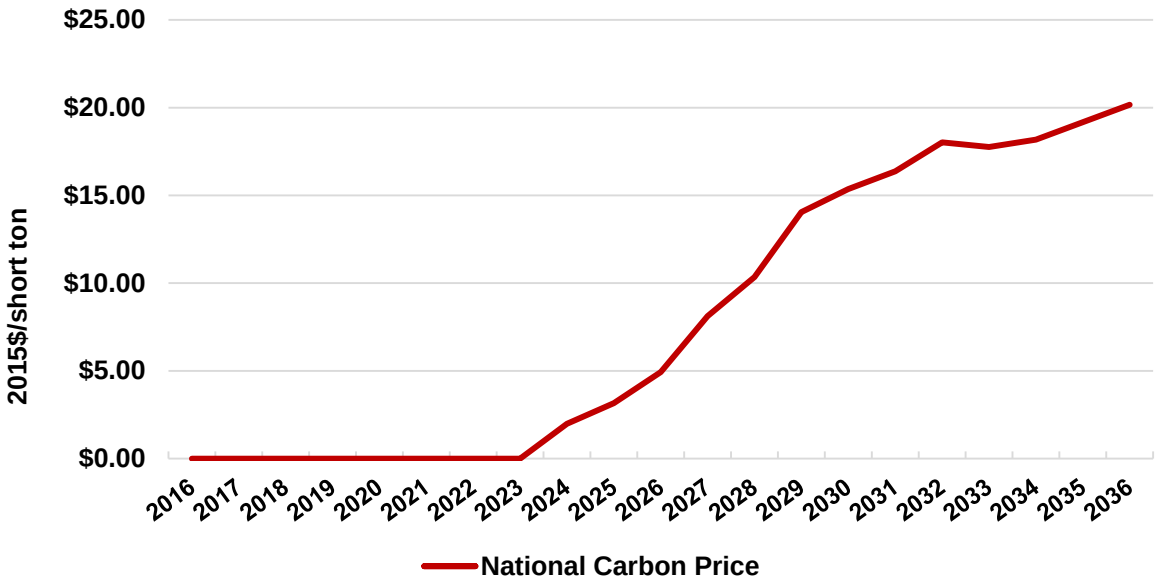
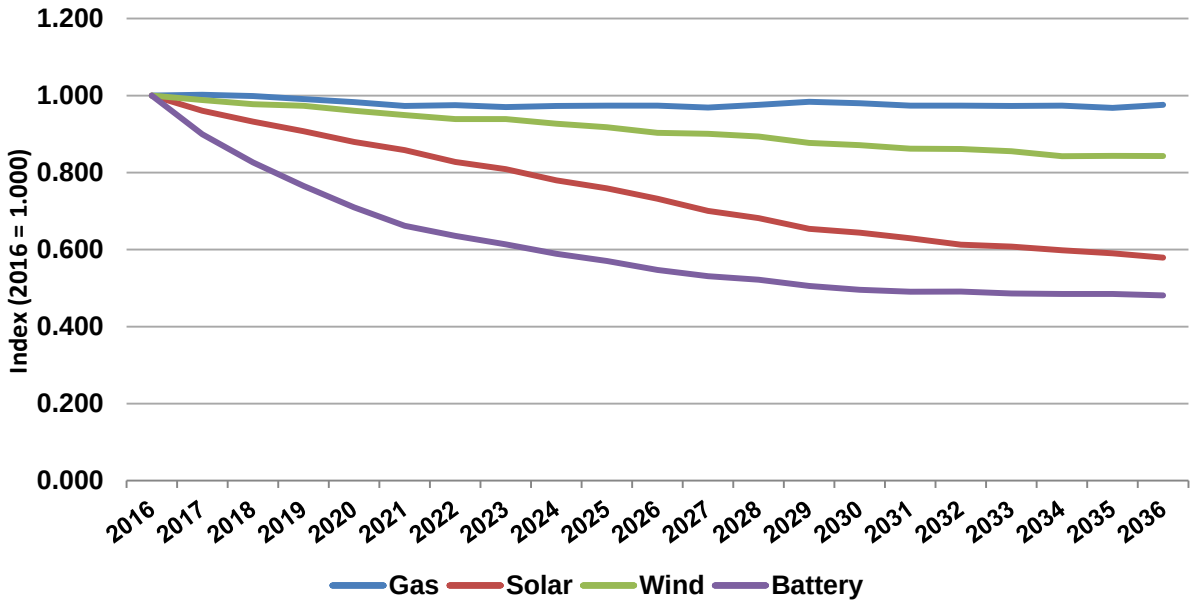


Figure 6.4 – Base Case Carbon Price Forecast (2015$/short ton)



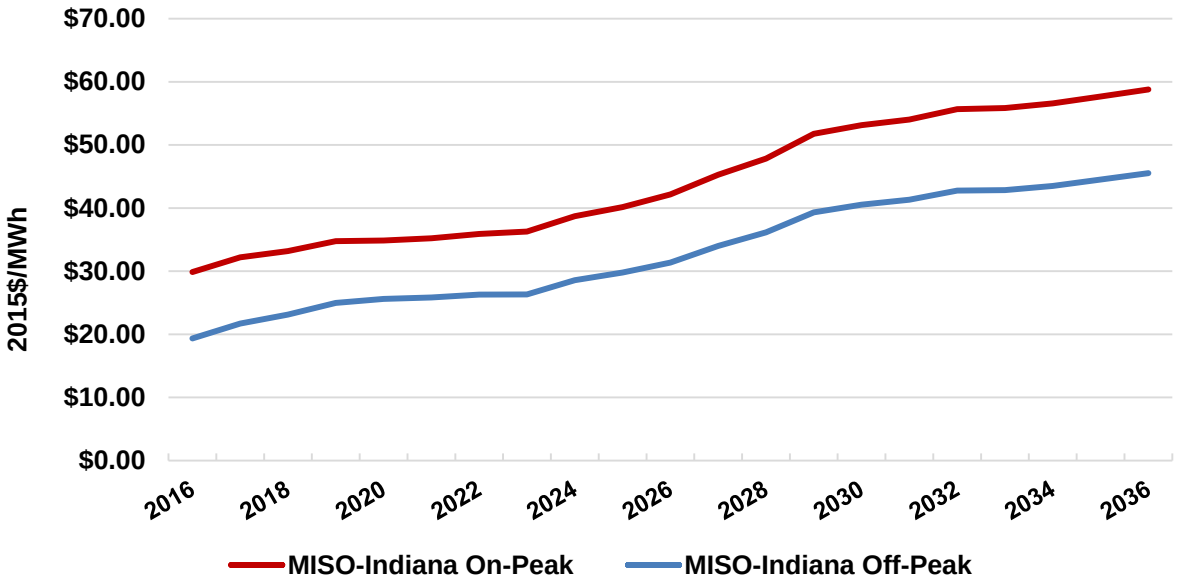
Current capital costs were developed by Burns & McDonnell, with a decline rate for each capital cost category (single cycle gas turbine, combined cycle gas turbine, solar, wind, and batteries) developed by Pace Global.

Figure 6.5 – Base Case Capital Cost Price Index Forecast (2016 = 1.000)



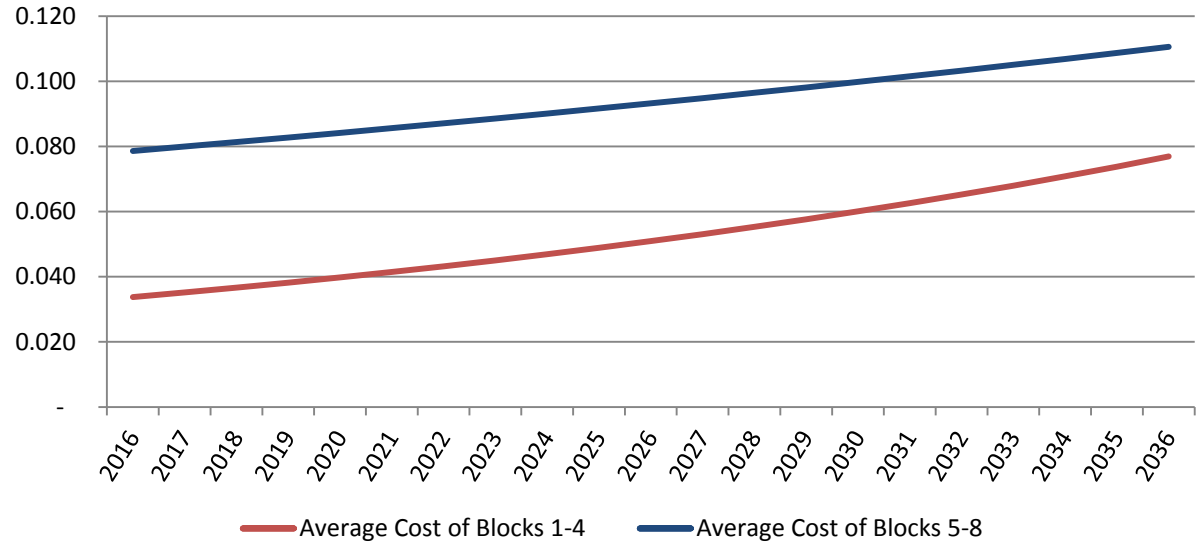
On- and off-peak power price forecasts were developed by Pace Global using the base case assumptions described above, together with Pace Global' s view of the greater MISO market, in the AURORAxmp power dispatch model.

Figure 6.6 – Base Case Power Price Forecast (2015$/MWh)



Levelized DSM costs were developed by Dr. Richard Stevie and described in detail in Section 5.2.3 DSM.

Figure 6.7 – Base Levelized Cost of DSM



6.1.2 Environmental Regulations

6.1.2.1 Effluent Limitations Guidelines (ELG)

On September 30, 2015, EPA published the final Effluent Limitations Guidelines rule (ELG). The rule sets strict technology-based limits for waste water generated from fossil fuel fired generating facilities and in particular, will force significant operational and technological changes at coal fired power plants. Below are the estimates used for IRP modeling.

AB Brown: ELG related changes 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 lined pond to handle process water (~$115M).

FB Culley: Required plant upgrades include conversion to dry bottom ash, FGD waste water treatment, and access to a landfill that can handle small quantities of dry bottom ash (~$75M).

Warrick U4: The exact ELG status of the Warrick plant will not be determined until the next NPDES permit renewal in 2018. For purposes of the IRP only, Vectren has assumed required upgrades and costs similar to FB Culley since the units are of similar design and size (~$40M, Vectren's portion of the total $80M estimate).

6.1.2.2 Coal Combustion Residuals (CCR)

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.

For AB Brown and FB Culley, it was assumed that ash ponds would be closed in place at the end of their useful life. The timing of the closures is dependent on continued need for the pond. For instance, if ELG related changes are made, such that the pond is no longer being used for ash storage, pond closure is then triggered. The base cost for the closures does not change regardless of future generation, and only the timing of the spend is affected in the modeling. Vectren has not historically utilized the ponds at the Warrick power plant for its share of the CCR generated by Warrick 4, and therefore is not liable for pond closure costs.

6.1.2.3 Clean Power Plan (CPP)

EPA finalized the Clean Power Plan that established carbon dioxide (CO_2) emission standards for a state's electric generating fleet in August 2015. States were given the discretion to set unit specific limits or adopt a mass-based or rate-based allowance trading program. The US Supreme Court issued a stay of the rule. It is not anticipated that final order on judicial review will come until 2017. After which, the state will develop the State Implementation Plan (SIP).

Vectren assumed the CPP would be upheld by the US Supreme Court, but the compliance would be delayed two years to 2024 due to the implementation delay caused by the stay. An average of currently available carbon costs was used for base case modeling. Note that the start dates for forecasts were adjusted to 2024 prior to averaging. More details can be found in Section 2.3, DEFINE BASE CASE AND BOUNDARY SCENARIOS.

To consider carbon (CO_2) emissions, Vectren assumed an emission allowance trading system with costs per short ton of emissions under all scenarios except the low regulatory scenario. Allowances were allocated based on Vectren's historical portion of CO_2 emissions relative to the state of Indiana totals for 2012. Allowances were based on the final Clean Power Plan (CPP) mass-based state targets. Vectren decreased the mass-based targets over time to reflect the interim and final targets of the rule. In all except the high regulatory scenario, the CPP interim period and final targets were delayed two years from the original start year (2022) in order to factor in delays associated with resolution of legal challenges pending before the United States Supreme Court.

6.1.2.4 316(b)

EPA issued their final rule regarding Section 316(b) of the Clean Water Act. The rule establishes requirements for cooling water intake structures (CWISs) at existing facilities.

This requirement applies to both FB Culley and Warrick 4. Standard fine mesh, fish friendly screens, and fish return systems were estimated to be $12-14M at FB Culley and $5-6M at Warrick 4 (Vectren's share).

6.1.3 Capacity Prices

The MISO capacity price has been difficult to predict as indicated by the volatile price history shown in Section 1.3.7, MISO. However, it is necessary for analysis purposes to have a capacity market price assumption to be included in the IRP modeling process. Some capacity will be bought or sold in practically every year due to the fact that load and planning reserve margin requirements vary incrementally from year to year while most supply side resources, such as generating units, come in large blocks with 30 to 55 year expected lifetimes. Vectren elected to use the Ventyx fall 2015 reference case MISO Indiana capacity price forecast for modeling purposes.

Figure 6.8 – Confidential Forecast Capacity Market Value (2015$/kW-yr)

6.1.4 Assumptions

Broadway Avenue Generating Station (BAGS) Unit 1 (as mentioned in Section 5.1.2, Natural Gas) has been mothballed and is earmarked for retirement in 2018. (47 years)

Broadway Avenue Generating Station (BAGS) Unit 2 (as mentioned in Section 5.1.2, Natural Gas) is earmarked for age related retirement in 2025. (44 years)

The Northeast Gas Turbine generating facility, NEGT 1 and NEGT 2, with capacities of 10 MW each, are currently scheduled to be retired from commercial operation in 2019. (55 years)

6.2 DEVELOPMENT OF ALTERNATE SCENARIOS

In order to develop several alternative scenarios for its IRP process, Vectren created a base case and several additional qualitative scenarios in its initial formulation. These scenarios were evaluated by a panel to estimate how key uncertainties (e.g., energy sales, gas prices) might fall relative to the base case. These estimates were quantified, averaged, and compared to Pace Global's independent estimates, which were closely aligned. Additionally, stakeholders provided Vectren with their list of possible uncertainties in a workshop held on April 7, 2016. Their inputs were considered and incorporated into the development of each alternate scenario.

These initial scenarios (base case plus 10 alternate scenarios) were then consolidated and reduced by Pace Global to a base case plus 6 alternate scenarios. The alternative scenarios were developed along three primary axes: regulatory, technological, and economic. Each axis is dichotomous, either being high or low, although there is only one technology scenario as technological innovation is assumed to either continue at the present rate or at an accelerated rate, but not at a "low" rate. From these three primary axes come five scenarios that provide a wide range of conditions in which to evaluate various portfolio planning strategies.

6.2.1 Description of Alternate Scenarios

As described in Section 2.3, DEFINE BASE CASE AND BOUNDARY SCENARIOS, the purpose of developing these "boundary" scenarios were to test a relevant range for each of the key market drivers on how various technologies are selected under boundary conditions. The specific conditions described in the following section are illustrative of the kinds of conditions that might generate values shown in the following

graphics. Values for the market drivers were based on an adjustment from the mean of a distribution and not a calculated value from that scenario.

6.2.1.1 High Regulatory

The High Regulatory scenario is characterized by a more heavily regulated path. The High Regulatory path is indicative of the following plausible circumstances relative to the base case:

- A much higher cost for compliance with the CPP, which begins on schedule in 2022, in part from less coordination among states that results in a mix of rate-based and mass-based compliance, but with many states not opting in to a national EPA backed program and in general more state-by-state command and control efforts for CO_2 emissions;
- More renewable adoption pushed through via mandates;
- Additional regulations on carbon on the horizon after 2030 that are higher than in the base case;
- Greater adoption of distributed generation in the form of solar and combined heat and power;
- Restrictions on fracking and fugitive methane emissions that limit gas supply growth, drive up gas prices, and result in an additional push and economic case for renewable energy; and
- Low economic growth that provides justification and room for greater regulation.

In the short-term (2016-2018), markets will not yet be characterized as “high regulatory” and will largely resemble the drivers in the base case. However, over the intermediate term some combination of the following might occur that results in the price trajectories shown below:

- The U.S. economy will continue to expand, albeit with signs that mid-term economic growth may be slower than in the base case. The customer base continues to grow, including among large C&I customers, with some initial

attention being paid to the contribution from large-scale industrial facilities to carbon emissions.

- Natural gas prices remain relatively low in the short-term, forcing operators to innovate rapidly to drive up efficiencies and drive down production costs or face bankruptcy. An ever greater share of U.S. gas production comes from shale gas, which is highly concentrated in Ohio, Pennsylvania, and West Virginia. This concentration of production renders U.S. supply more susceptible to short-term curtailments (freeze-offs) and longer-term economic downswings (and thus lower gas production out of this region).
- Coal prices remain depressed as in the base case, but with an economic outlook for coal-fired generation in the mid-term that appears to be increasingly regulated.
- Meanwhile, CO_2 prices in the California and RGGI markets begin to move upward in anticipation that these programs will be CPP compliant after 2022.
- Market penetration of solar and wind generation continues to grow at a fast rate, albeit still from a relatively small base, with state- and federal-level mandates supporting their implementation through relatively inefficient and costly market mechanisms. As a result, a full recovery of costs to maintain national transmission and distribution grids remains difficult, and underinvestment continues in modernizing the underlying power grid infrastructure.
- In the short-term, these market forces do not indicate an overly heavy interventionist hand from the state. However, they do presage a higher regulatory level to come in the medium- to long-term as the economy grows relatively weakly, market power prices rise, and the state intervenes in an attempt to stabilize markets.

In the medium-term (2019-2025), the following is representative of the high regulatory projections:

- At the beginning of the CPP compliance period in 2022, little progress has been made among states to opt into efficient national trading mechanisms. States seek

compliance individually or on a regional basis that results in the need for higher cost emission reductions and increases the overall compliance cost of the program.

- Further, the EPA could issue additional CPP reduction goals for the 2031 and beyond time period, which are significantly stricter than the current CPP. All of these developments lead to increased costs for CPP compliance that in turn lead to higher market power prices and a lower level of load growth as compared to the base case.
- Power markets are also constrained by higher gas costs stemming from increased regulation on natural gas fracking and fugitive methane emissions from distribution pipelines and drilling operations.
- Environmental concerns over fracked gas (e.g. induced seismicity, contaminated well sites) and a sustained public affairs campaign lead to national restrictions, higher production costs, and a lower supply base for natural gas.
- Coal-fired generation is highly disfavored due to ever-tightening restrictions on plant emissions, leading to lower coal prices than in the base case based on lax demand, but higher costs for coal-fired generation that lead to higher coal-fired plant retirements. Export restrictions on oil, gas, and coal are reinstated or increased.
- The U.S. economy undergoes another major market correction and resulting recession, leading to sweeping market interventions that include reforms such as mandated improvements to energy infrastructure whose costs are passed along to consumers. This leads to a high rate of retirement of coal plants, replaced by costly renewables that require commensurate and costly investment in energy storage. It also includes costly upgrades to transmission and distribution (T&D) infrastructure to guard against cyberattacks. Strong targets for distributed generation penetration, energy conservation, demand-side management, and energy efficiency lead to increased costs and higher electricity rates for existing energy company customers.

In the long-term (2026-2036), the high regulatory scenario enters into the 2030s at the same time as efforts to reduce carbon footprint become ever more intensified and target all areas of the traditional energy market.

- A new round of global climate talks is successful and includes binding targets, which precipitates an ever increasing regulatory role of the government in the energy sector, that help to keep CO_2 and power prices high.
- Toward the end of the forecast period, the scale of renewable penetration is such that costs begin to move downward once again as fuel costs become less important, and capital costs decline with massive economies of scale for renewable production and an efficient labor force experienced in distributed generation. The U.S. market experiences a period of moderate and sustained growth, which allows some breathing room in terms of new regulatory restriction, but not enough incentive to roll back existing restrictions, which continue to push high levels of coal retirements and renewable additions.

6.2.1.2 Low Regulatory

The low regulatory scenario was developed to establish a lower boundary condition on regulatory reform. Relative to the base case, this scenario is characterized by free market attitude in which few new regulatory restrictions are put forward and many of those that are currently in motion (e.g. CPP) are shelved. Regulations that do enter into force are implemented at lower cost than expected.

In the short-term (2016-2018):

- Political leaders shelve the national carbon regulatory scheme (the CPP).
- The U.S. economy continues to improve (as it does in the base case), which in turn leads to the beginnings of rising energy sales.
- Natural gas costs remain relatively low, as do coal prices, which help to constrain market power prices to the same moderate level as in the base case. Capital costs remain moderate as the commodity price rout continues and as wages grow only slowly.

The main difference between the outlook in this scenario and the recent past is that economic or forced retirements are expected to be lower than in the base case (in the medium-term). A strong economy, low fuel costs, and robust load growth help to sustain the existing generation fleet that includes coal plants. This period of efficient market operations helps to keep power prices on the lower side and stave off new regulatory interventions.

In the medium-term (2019-2025):

- The U.S. market continues to improve and grow which limits economic plant retirements and encourages additional deployment of advanced gas-fired generation to meet load growth.
- Although absolute emissions begin to rise again as the economy grows, per capita energy intensity declines, and as a result the CPP remains the only significant piece of regulation to move forward during this timeframe. Fuel prices remain moderate (gas) to high (coal).
- Commodity costs begin to rise once again as the global economy picks up steam, though not enough to move capital costs away from the base case forecast. Overall, the strength of the economy helps to limit the desire to intervene with any potential market corrections and new regulatory regimes.

In the long-term (2026-2036):

- Few new power market interventions are sought or required. Energy markets continue to work well, providing affordable electricity and fueling a sustained period of economic growth.
- However, this economic growth reverts to a more moderate level in the long-term, similarly moving load growth to a moderate level.
- Capital costs rise steadily in the healthy economy as interest rates are pushed higher by federal monetary policy makers. Retirements move to a more moderate level as older plants are forced to retire and capacity additions rev up to handle

these retirements as well as the continued economic growth (despite higher capital costs).

6.2.1.3 High Technology

The high technology scenario was constructed to be indicative of significant advances in energy storage technology, renewable energy deployment, emissions reduction and CO_2 removal technology, high efficiency gas-fired generation, and natural gas extraction productivity. Overall, there are significant developments in technologies that improve energy efficiency, which helps to mitigate the load growth that might otherwise be expected in a high technology scenario with robust economic growth.

In the short-term (2016-2018):

- The recent high pace of coal plant retirements continues (mostly due to MATS regulation but also for economic reasons), driven largely by initially low gas prices that create difficult economic conditions for coal-fired generation.
- The pace of economic expansion continues to grow as the U.S. economy becomes the lead driver of global economic health. However, this also begins to push interest rates higher with potential impact on future capital costs.
- Because fuel costs remain low initially (shale gas oversupply continues while coal demand remains soft), market power prices also remain muted despite moderate energy sales growth in an increasingly healthy U.S. economy.
- Low natural gas prices begin to have an effect on production, reducing the growth rate for new supplies, while the strong uptick in gas demand from LNG exports and other sectors helps to tighten the market and push gas prices higher in 2018.

In the medium-term (2019-2025):

- The main characteristic of the high technology scenario is that in the early 2020s timeframe a technology breakthrough occurs in the renewables market and possibly also in the storage market, such that the cost for renewables declines

dramatically, which in turn encourages a faster shift to renewables from fossil fuels.

- This breakthrough results in an incremental reduction in natural gas demand, in the latter half of the medium-term, as compared to the base case. Coal plant retirements continue at a relatively high rate. Whereas previously these retirements were driven primarily by competition with existing natural gas-fired generation, they are increasingly being replaced with renewables and high efficiency combined cycle gas turbine (CCGT) plants.
- Accordingly, the high rate of retirements and capacity additions/replacements continues into the medium-term. Many of the expected costs that are associated with CPP compliance are mitigated by advances in generation (gas and renewables), distribution, and storage technologies. Gas prices remain low despite somewhat tighter supply/demand dynamics, which prompts another wave of improvements in drilling and fracking technology and helps to keep gas prices at relatively low levels.
- The low gas prices are coupled with lower gas demand in the medium-term as renewables growth begins to pick up steam. Interest rates continue to move higher, which in turn pushes capital costs higher than in the base case.
- Distributed generation plays a much greater role in the high technology scenario, given advances in battery technology, gains in photovoltaic costs and efficiencies, and a more coordinated approach to managing variable wind generation across regional transmission organizations (RTO) and independent system operators (ISO).
- Given advances in battery technologies, there is a higher penetration rate of electric vehicles than in the base case. This increases load growth, but also allows for a more efficient distribution of resources as the growing fleet of vehicle batteries help to manage peak power load and power price volatility.

In the long-term (2026-2036):

- A well-functioning and expanding U.S. market helps to keep regulatory interventions beyond the CPP at a minimum.
- Fuel costs continue to remain relatively low.
- The pace of retirements and capacity additions continues in the high technology scenario, albeit slightly lower than otherwise would be with lower capital costs (as a result of interest rates that remain high). Most of the retirements would come from older gas plants (including single cycle gas turbine peakers) while most of the additions would come from residential and commercial solar, wind, CHP, and combined cycle gas turbine facilities. There are fewer feedback mechanisms at play in this scenario, as the technology improvements over time help to maintain low fuel and capital costs and keep the energy sector on a steady path of moderate growth.

6.2.1.4 High Economy

The high economy/market scenario was constructed to be indicative of a market that has a robust and growing U.S. economy keeping upward pressure on all of the major market outcome categories, including load growth, fuel costs, power prices, and capital costs. This growth is in the absence of a major technological breakthrough. Existing generation resources are needed to maintain this economic expansion, limiting the number of retirements while accelerating the number of capacity additions. While this scenario shares many of the attributes of the previous high technology scenario, the pace of technological innovation is not as dynamic, and therefore beneficial to keeping prices and costs in check. Regulations are similar to those in the base case.

In the short-term (2016-2018):

- The U.S. economy makes substantial gains in reducing the unemployment level while creating new jobs that bring discouraged workers back into the work force. The housing market continues to improve, as do the C&I sectors.

- Commodity costs remain low in the short-term, helping to fuel this period of continued economic expansion. All planned capacity additions move forward in a timely manner, while somewhat fewer coal plants announce a planned retirement due to economic or regulatory conditions. In the short-term, regulation continues in a business-as-usual manner.

In the medium-term (2019-2025):

- Outlook in this scenario begins with many positive indicators that continue into the medium-term. However, the expansion of the economy becomes a partial victim of its own success.
- Strong economic growth in the U.S. market helps to push energy sales higher, which in turn pushes underlying fuel and capital costs higher. A relatively strong feedback mechanism begins to assert itself under these circumstances, in which technology does not play as great a role in this scenario as it does in the high technology scenario. Accordingly, what began as very strong growth begins to become more restrained toward the end of the medium-term.
- Existing technology remains important in maintaining the high rate of load growth because technology does not necessarily play as large a role in this scenario. Accordingly, very few coal, gas, or other plants are retired for economic or regulatory reasons, while new plants are added on a relatively consistent basis.
- The CPP proceeds along the lines of the base case, with CO_2 costs at a similar level. Gas costs are incrementally higher, as are the costs for renewables.

In the long-term (2026-2036):

- Global economic activity begins to increase as developing markets such as India move to the forefront and drive growth.
- Global growth begins to apply upward pressure to global LNG and coal costs as well as commodity costs for materials, which in turn drives up market power prices here in the United States.

- Energy sales growth remains strong, as do capacity additions, but tighter global markets put upward pressure on several of the other market outcomes.
- Long-term outlook in the high economy/market scenario begins to push toward an era of high prices, high costs, high capacity additions, and high load growth. Given that the economy is doing well in this scenario in the long-term, market regulators feel they have greater latitude to implement additional regulations. This provides a modest feedback loop to slightly dampen U.S. GDP growth over time.

6.2.1.5 Low Economy

The low economy/market scenario is characterized by sluggish economic growth both domestically and globally, including (in the short-term) important growth markets like China, Europe, and Brazil. While some conditions are favorable to the U.S. economy, including low fuel costs, most indicators point toward headwinds for growth in the GDP level. Moderate CO_2 prices and low load growth help to keep market power prices on the low end of the scale, which in turn keep capacity additions low. Market regulators have less latitude to implement new regulations, as the economy cannot afford them in this low economy scenario.

In the short-term (2016-2018):

- The U.S. economy begins this period at a relatively good growth rate, but the rest of the world does not fare as well, which begins to weigh on the U.S. economy.
- As a result, load growth begins to slow gradually as U.S. manufacturers and exporters curtail operations, which in turn leads to low market power prices.
- Low gas prices remain low as demand dries up (incrementally) even while supply remains healthy.

In the medium-term (2019-2025):

- As the global economy continues to stagnate or degrade, the U.S. economy also begins to be affected negatively. GDP growth is less than half a percent, which

particularly hurts the power sector given the strong role that energy plays in fueling economic growth (though efficiency gains have been muting this role of late).

- With little to no growth in energy sales, few new plants are built and plants continue to retire as they reach the end of their technical and economic lives. Fuel costs remain relatively low, given the lack of demand.
- Capital costs remain moderate as interest rates maintain a modest level, as the policy makers are reluctant to return to an era of artificially low interest rates.

In the long-term (2026-2036):

- By the 2030's, the world market is slowly coming out of its slump, but recovery is slow as progress is held back by strong global adherence to emissions targets set forth in climate negotiations.
- Low fuel prices continue, albeit slightly higher as demand eventually responds to sustained low prices. Overall, in the long-term the low economy/market scenario begins to revert back to resemble, in part, the base case with more moderate levels of market outcomes and drivers.

6.2.1.6 Base Large Load Addition

This scenario adds 100 MWs of load beginning in 2024 to the base forecast. All else is equal to the base scenario.

6.2.2 Coordinated Forecasts for Alternate Scenarios

6.2.2.1 Methodology

A very structured and coordinated approach for developing alternate scenarios was undertaken as part of this IRP process. It has been observed that future markets are driven principally by economic forecasts, regulations, and technological change. Accordingly, a set of alternate scenarios was developed around the base case that include a "low and a high regulatory" case, a "low and a high" economic case, and a

"high technology" case. Each of these scenarios has an internally consistent narrative. For example, the "high regulatory" case is associated with both a more strict Clean Power Plan case, plus fracking restrictions, or other water usage issues that would limit shale gas development, and more stringent regulations on coal.

This methodology provides a useful starting point for integrated forecasts that are fully developed and consistently applied. Under each of these scenarios, a perspective was developed on how key variables such as load growth, fuel prices (e.g. coal and gas prices), emission prices, and capital costs for different technologies, retirements, and new builds are expected to move relative to the base case forecasts in the short term, medium term, and long term. These narratives were converted to a directional change for each variable, and then actual values were developed in a consistent manner.

These alternate scenarios were developed to be plausible, not necessarily highly probable. They are intended to provide boundary conditions against which to test each portfolio or investment strategy. A description of the development of these integrated forecasts for each of the key variables is provided in this document. For the development of these scenarios, stochastic distributions of each of the key variables (e.g. load, gas prices, technology costs, etc.) were developed, with select values that are either one standard deviation above or below the base case values for that variable. In this way, a consistent methodology was applied across each of the integrated scenarios, by creating both a directional variable movement and a consistent quantified value for the variable that is consistent with the description of that alternate scenario.

A hybrid approach that combines a deterministic forecast for key market drivers together with probabilistic stochastics was used to inform the characterization of uncertainty. Stochastic distributions that reflect a combination of historical data and informed judgment tend to capture "black swan events" that are impossible to forecast, but tend to occur quite frequently. Some variables, like carbon regulations, have no historical data and others, like gas prices, have had fundamental market changes that

will influence the future differently from the past. Accordingly, a hybrid approach combined with expert judgment by market consultants was used to develop and inform the alternate scenarios.

6.2.2.2 Model Inputs

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

Figure 6.9 – Vectren Total Load (GWh) and Peak Load (MW) Alternate Scenarios

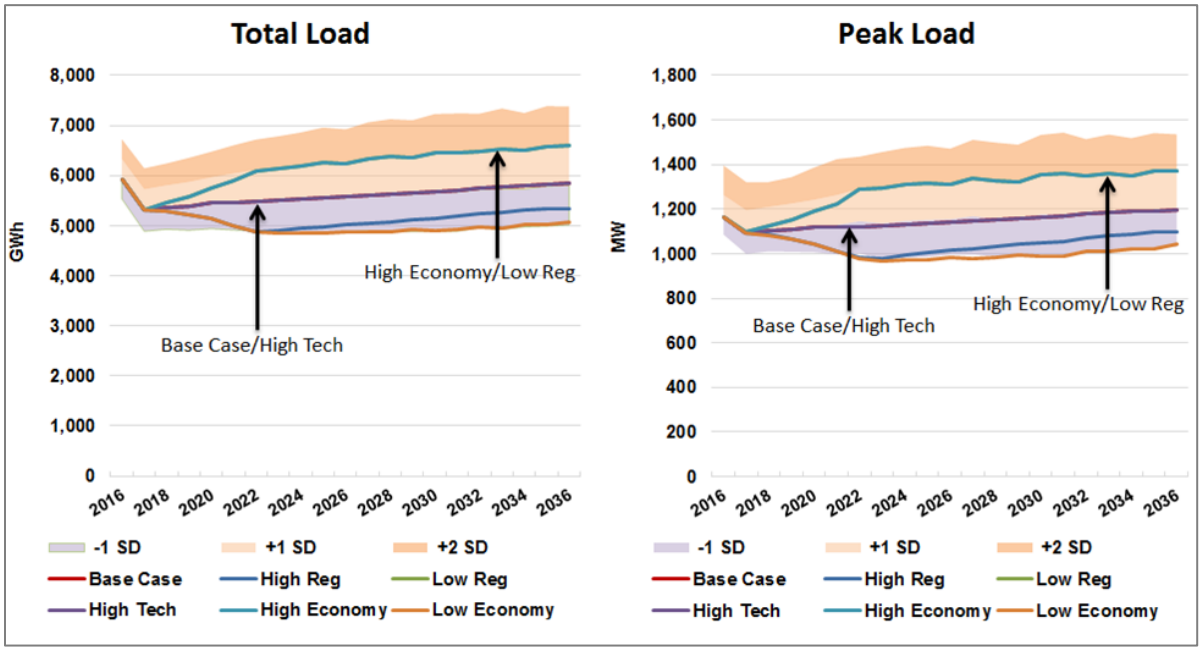


Figure 6.10 – Coal Alternate Scenarios (2015$/MMBtu)

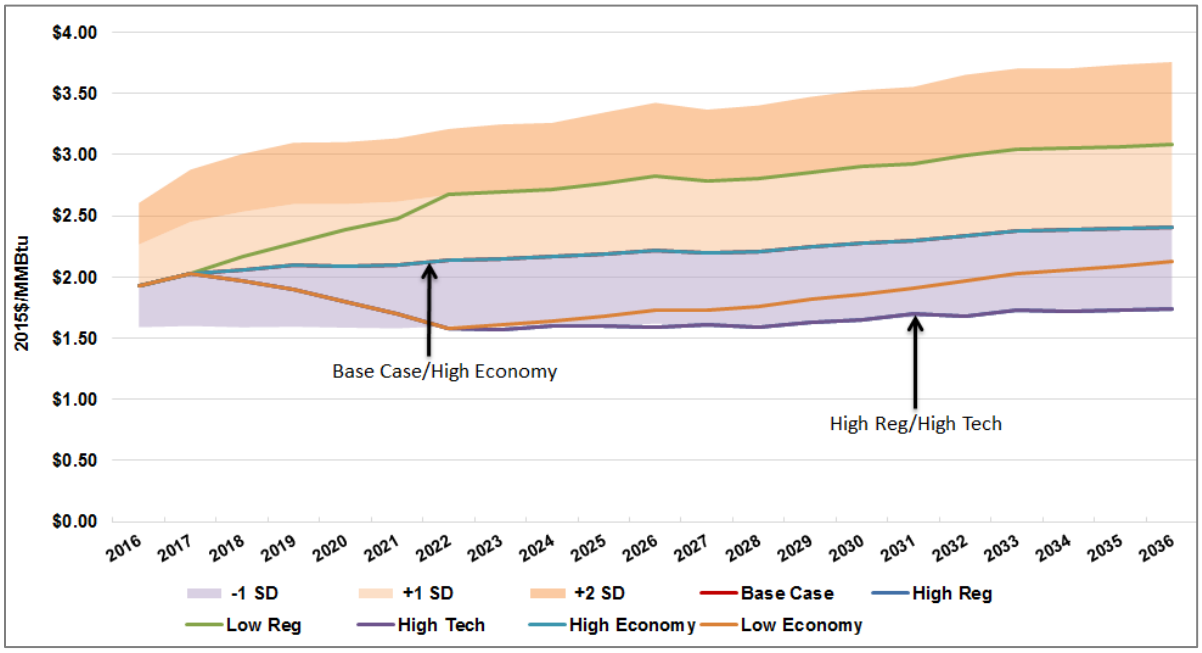
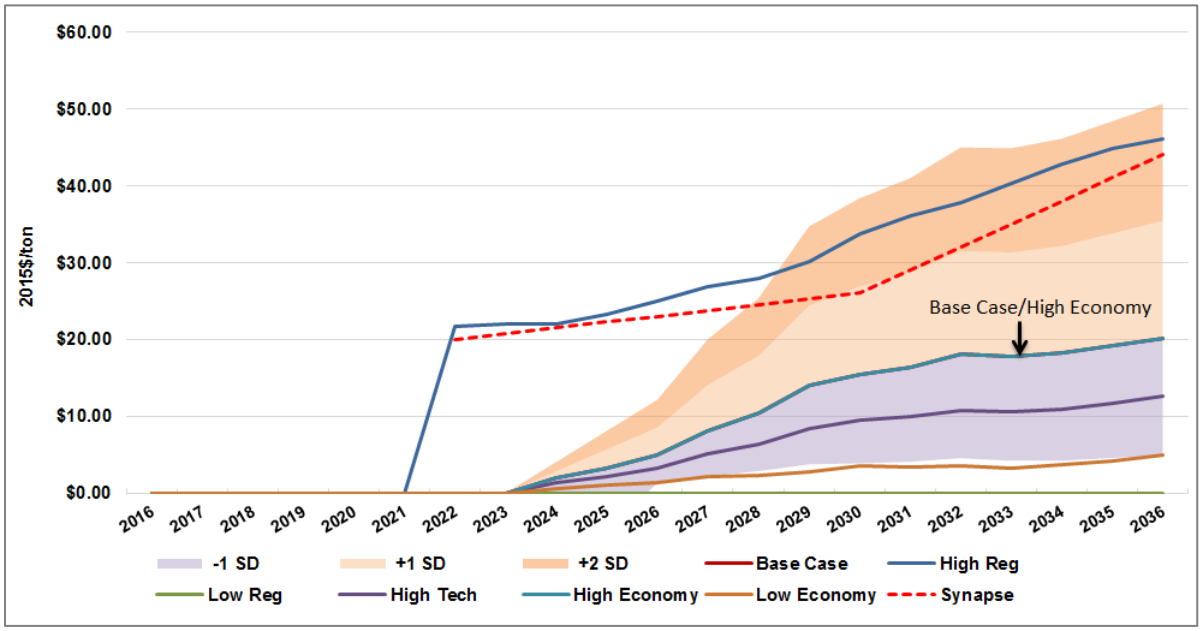


Figure 6.11 – Carbon Alternate Scenarios (2015$/ton)[48]



[48] Note that Synapse refers to the Mid Case on page 8 (adjusted for 2024 start date) from Spring 2016 National Carbon Dioxide Price Forecast, Updated March 16, 2016, Synapse Economics Inc., http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008.pdf

Figure 6.12 – Natural Gas (delivered to Indiana) Alternate Scenarios (2015$/MMBtu)

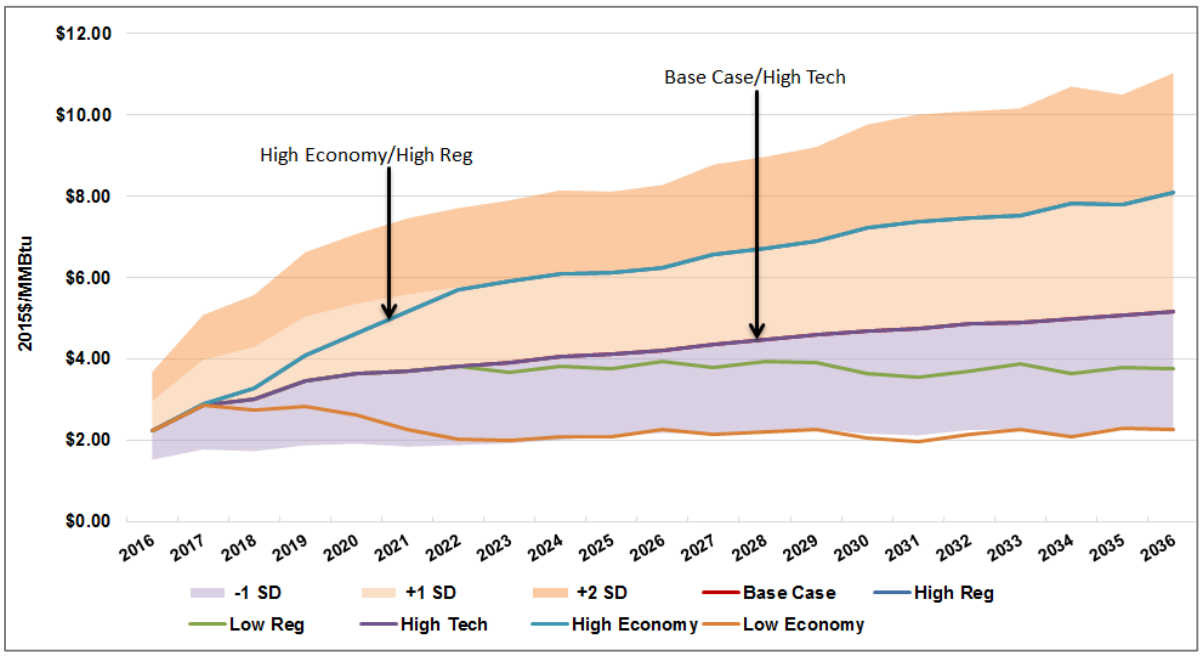


Figure 6.13 – Indiana Hub On- and Off-Peak Power Prices Alternate Scenarios (2015$/MWh)

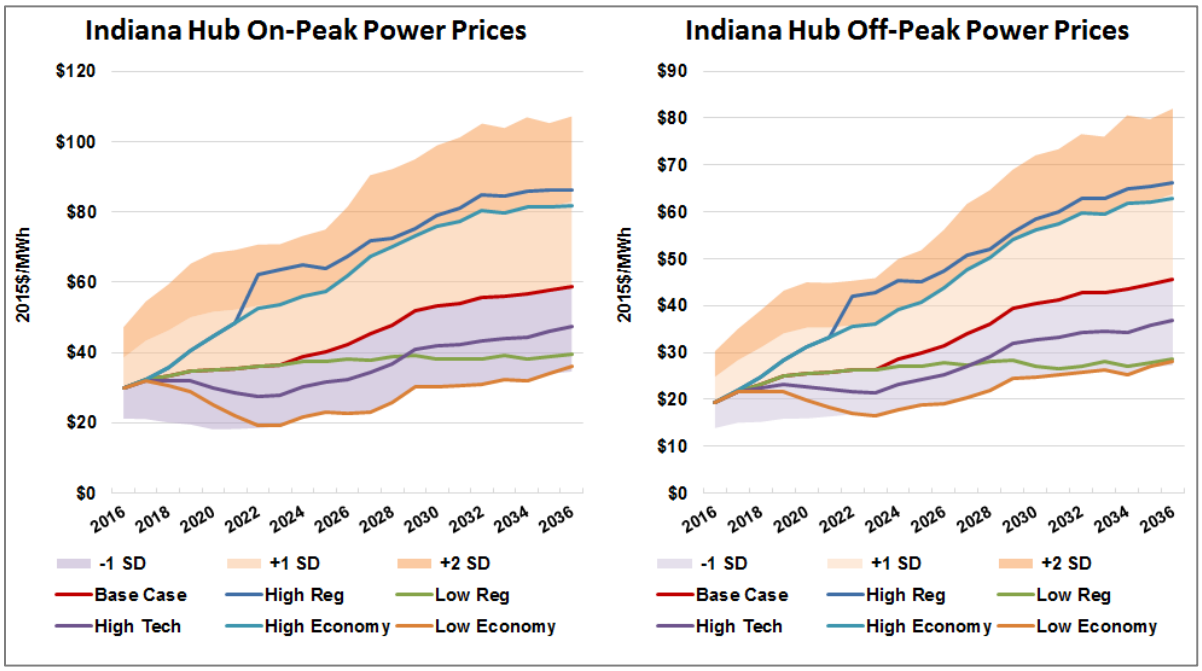


Figure 6.14 – Gas-Fired Capital Costs Alternate Scenarios (Index, 2016 = 1.000)

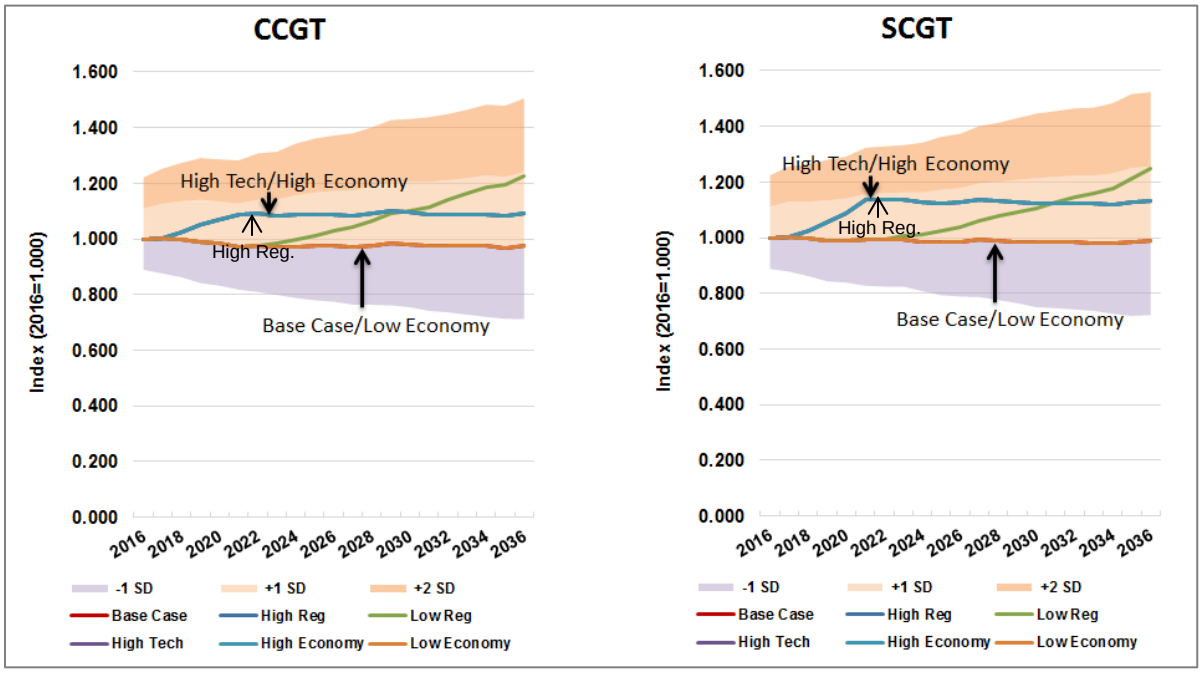


Figure 6.15 – Solar and Wind Capital Costs Alternate Scenarios (Index, 2016 = 1.000)

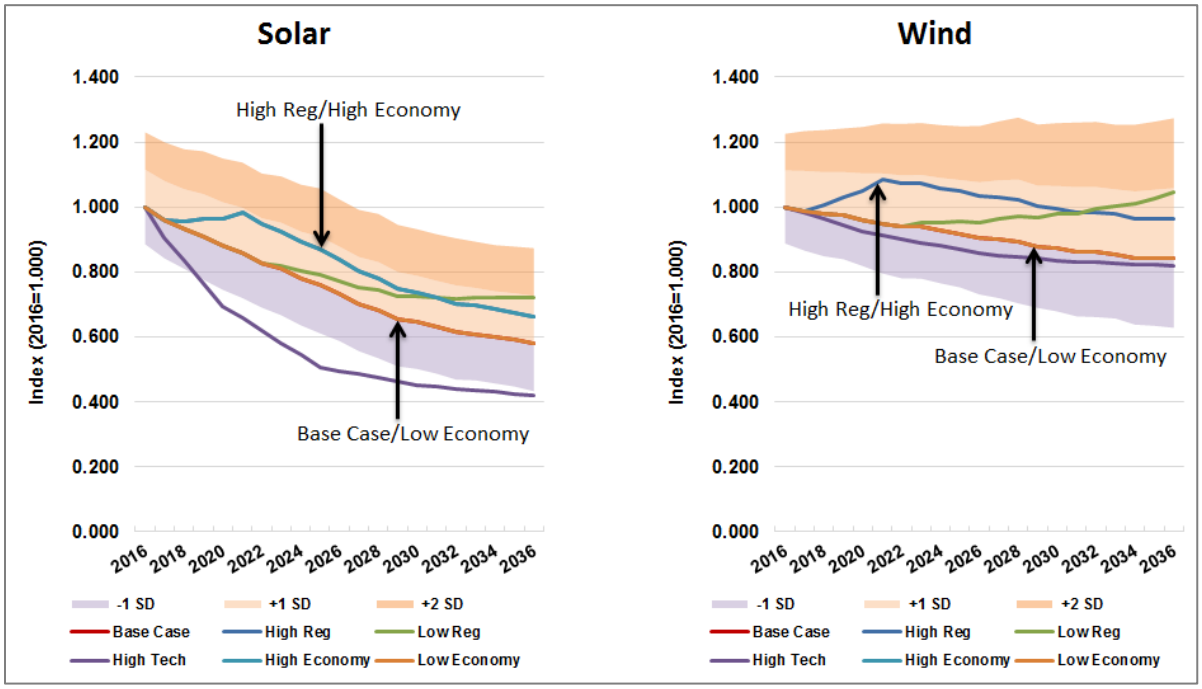
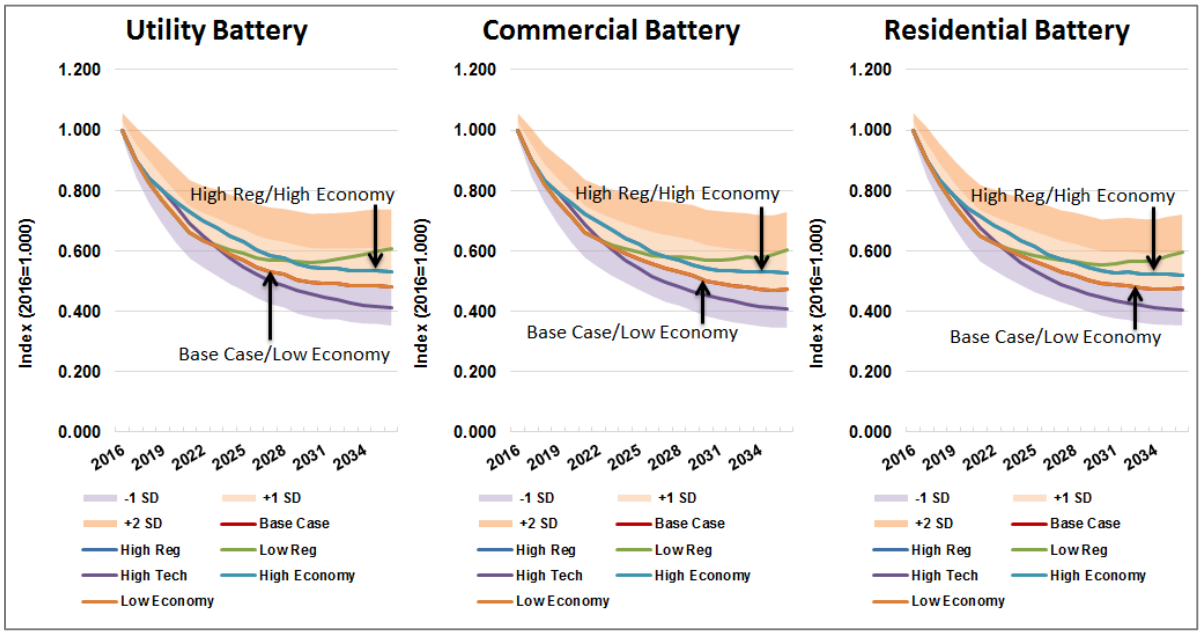


Figure 6.16 – Battery Capital Costs Alternate Scenarios (Index, 2016 = 1.000)



SECTION 7
SCREENING ANALYSIS

7.1 DEVELOP PORTFOLIOS

7.1.1 Optimized Portfolios

7.1.1.1 Model Description

Vectren continues to use the Strategist modeling software from ABB Group (formerly Ventyx), as it has in its last several IRP studies. This software has traditionally been used by some of the other Indiana utilities as well as utilities in other states. The modeling performed by Vectren provides important information to evaluate potential future resource needs.

Strategist is a strategic planning system that integrates financial, resource, marketing, and customer information. Strategist is able to simultaneously consider all aspects of integrated planning at the level of detail required for informed decision making. Strategist handles production costing, capital expenditures and recovery, financial and tax implications, and optimization all within one software system.

An optimization method has three elements: an objective, constraints, and alternatives. For the electric integration process, the three elements can be summarized as follows:

7.1.1.2 Objective

The objective of the analysis was to determine the optimal resource plan by minimizing the net present value (NPV) of customer costs. For the purposes of this discussion, the planning period NPV is defined as the net present value of operating costs including fuel, related emissions, and capital costs. Power purchases and sales are also included in the NPV analysis for the 20 year period, 2017 through 2036. NPV numbers were developed by integrating the various scenario assumptions into the optimization model. The generation options within the scenarios, along with unit retirements, additional DSM, and purchasing capacity from the market were compared against the capacity needs of the scenario yielding seven optimized low cost NPV plans.

7.1.1.3 Constraints

The primary constraint was to maintain a minimum planning reserve margin (PRM). MISO has moved to an unforced capacity (UCAP) PRM in the last couple of years. The UCAP accounts for the amount of installed capacity (ICAP) or nameplate capacity available at system's megawatt peak hour of the peak day after discounting for the time that the generating facility is not available due to historical outages such as maintenance and repairs. The UCAP PRM is subject to change each year depending on MISO's projected need and based on annual system reliability studies. For the planning year 2016/2017, MISO set forth a UCAP PRM of 7.6%. This means that Vectren must maintain at least 7.6% over the peak demand of its customers on a UCAP basis coincident to the MISO system peak. The goal is to determine the minimum planning reserve margin that would result in the MISO system experiencing a loss of load event less than one day every ten years. Other constraints include the project development and build times for new construction alternatives, transmission import constraints, reliability considerations, and the characteristics of existing resources and demand.

7.1.1.4 Alternatives

A broad array of alternative generation and DSM was included within the optimization analysis. The full range of supply-side resource alternatives were identified and discussed in Section 5, RESOURCE OPTIONS.

7.1.1.5 Results

There were a number of non-optimized portfolio shutdown decisions that were fixed due to age or other related issues including the following:

- End Warrick 4 joint operations mid-2020 (132 MW UCAP)
- Northeast 1 and 2 by end of 2018 (18 MW UCAP)
- BAGS 2 by end of 2024 (58 MW UCAP)

Additionally, a 4 MW solar plant is assumed to be operational by 2018. This is representative of 4-6 MWs of several energy company owned solar projects that are expected to be in place by this time, including:

- 2 MW universal solar power plant with a 1 MWh battery storage system
- solar plant with the City of Evansville, details of which are expected to be finalized in the first quarter 2017, and
- other potential project discussions (on-going).

Under all scenarios, additional resources were not selected until joint operations cease at Warrick 4, causing a planning reserve margin shortfall. At the end of 2023, economic shutdown of coal units occurred under each scenario. A 2x1 combined cycle gas turbine was selected to replace the retiring coal capacity. Certain portfolios selected a simple cycle gas turbine in addition to the combined cycle gas turbine. See the optimized and deterministic portfolio tables in Technical Appendix Attachment 7.1 IRP Portfolio Summary Report for more details. For a graphical representation of each portfolio see Technical Appendix 7.2 Balance of Loads and Resources. Detailed Strategist model information can be found in Confidential Attachment 7.3 Portfolio Input-Output Report.

In the **Base Scenario (aka Gas Heavy) Portfolio**, market capacity purchases occur through 2023. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking) and a 1xF-class SCGT with an annual base load capacity of 220 MWs. Some market capacity purchases and solar capacity installations begin in 2032 and continue through 2036.

Figure 7.1 – Base Scenario (aka Gas Heavy) Portfolio

	(B) Base Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2022 (68-73 MW Market Capacity)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 2023 (77 MW Market Capacity) Combined Cycle Gas Turbine (889 MW) Simple Cycle Gas Turbine (220 MW)
2030-2036	**New** 2032-2036 (1-9 MW Market Capacity) 36 MW Solar

In the **Base + Large Load Scenario Portfolio**, there is 1% EE (2018-2036), market capacity purchases through 2023, and 4 MW of DR each year through 2024. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and are replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking) and a 1xF-class SCGT with an annual base load capacity of 220 MWs. Market capacity purchases begin again in 2030, with 50 MW of solar in 2032 and 9 MW solar in 2035 and 2036.

Figure 7.2 – Base + Large Load Scenario Portfolio

	(C) Base + Alternate Load Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4MW Solar 2020-2022 (26-43 MW Market Capacity) 2018-2022 (1.0% Energy Efficiency) 12 MW Demand Response
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 8 MW Demand Response 2023 (19 MW Market Capacity) Combined Cycle Gas Turbine (889 MW) Simple Cycle Gas Turbine (220 MW) 2023-2029 1.0% Energy Efficiency
2030-2036	**New** 2030-2036 (1-9 MW Market Capacity) 68 MW Solar 2030-2036 1.0% Energy Efficiency

The **High Regulatory Scenario Portfolio** is characterized by 1% EE (2018-2036), 4 MW solar in 2018, and market capacity purchases beginning in 2020. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). 200 MW of wind come online in both 2030 and 2031, with significant market capacity purchases in 2030 through 2036.

Figure 7.3 – High Regulatory Scenario Portfolio

	(D) High Reg. Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2022 (39-47 MW Market Capacity) 2018-2022 (1.0% Energy Efficiency)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** Combined Cycle Gas Turbine (889 MW) 2023-2029 (28-106 MW Market Capacity) 2023-2029 1.0% Energy Efficiency
2030-2036	**New** 2030-2036 (72-100 MW Market Capacity) 400 MW Wind 2030-2036 1.0% Energy Efficiency

The **Low Regulatory Scenario Portfolio** has a market capacity purchase of 43 MW in 2020, 1% EE (2018-2036), and the installation in 2021 of a 1xF-class SCGT with an annual base load capacity of 220 MW. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). A second 1xF-class SCGT with an annual base load capacity of 220 MW is installed in 2025.

Figure 7.4 – Low Regulatory Scenario Portfolio

	(E) Low Reg. Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020 (43 MW Market Capacity) 2018-2022 (1.0% Energy Efficiency) Simple Cycle Gas Turbine (220 MW) 12 MW Demand Response
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 8 MW Demand Response Combined Cycle Gas Turbine (889 MW) Simple Cycle Gas Turbine (220 MW) 2023-2029 1.0% Energy Efficiency
2030-2036	2030-2036 1.0% Energy Efficiency

The **High Economy Scenario Portfolio** includes a market capacity purchases beginning in 2020, 2% EE (2018-2036), and the installation in 2022 of a 1xF-class SCGT with an annual base load capacity of 220 MW. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down, replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). 9 MW solar come online in 2027 and substantial wind is built 2030-2036.

Figure 7.5 – High Economy Scenario Portfolio

	(F) High Economy Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 8 MW Demand Response 2020-2021 (10-27 MW Market Capacity) 2018-2022 (2.0% Energy Efficiency) Simple Cycle Gas Turbine (220 MW)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 12 MW Demand Response Combined Cycle Gas Turbine (889 MW) 9 MW Solar 2023-2029 2.0% Energy Efficiency
2030-2036	**New** 400 MW Wind 2030-2036 2.0% Energy Efficiency

The **Low Economy Scenario Portfolio** shows market capacity purchases 2020 through 2036. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). 9 MW and 50 MW of solar come online in 2035 and 2036, respectively.

Figure 7.6 – Low Economy Scenario Portfolio

	(G) Low Economy Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2022 (68-73 MW Market Capacity)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 2023-2029 (67-155 MW Market Capacity) 20 MW Demand Response Combined Cycle Gas Turbine (889 MW)
2030-2036	**New** 2030-2036 (161-188 MW Market Capacity) 59 MW Solar

Finally, the **High Technology Scenario Portfolio** includes up to 91 MW of market capacity purchases through 2023. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking), as well as a 1xF-class SCGT with an annual base load capacity of 220 MW. Minimal market capacity purchases occur in 2035 and 2036.

Figure 7.7 – High Technology Scenario Portfolio

	(H) High Tech. Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2022 (82-87 MW Market Capacity)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 2023 (91 MW Market Capacity) Combined Cycle Gas Turbine (889 MW) Simple Cycle Gas Turbine (220 MW)
2030-2036	**New** 2032-2036 (1-10 MW Market Capacity) Battery 10 MW / 40 MWh 9 MW Solar

7.1.2 Stakeholder Suggested Portfolios

In addition to the scenario optimized portfolios, Vectren solicited input from public stakeholder attendees during the second public stakeholder meeting for two additional portfolios. These stakeholder portfolios include less combined cycle gas capacity additions (331 MW) compared to the other portfolios, 1,000-1,200 MW of wind capacity additions, 804-904 MW of solar capacity additions, 100-200 MW of battery storage capacity, and 30 MW of CHP capacity. Both stakeholder portfolios see 1,061 MW of coal capacity retirement, similar to the other portfolios, but fewer capacity market purchases. Energy efficiency plays a relatively larger role in the two stakeholder portfolios.

The **Stakeholder Portfolio** was developed with input from attendees during the second stakeholder meeting. It is characterized by 2% EE (2018-2036), market capacity purchases through 2021, and 4 MW of DR each year 2020 through 2024. In 2024, AB Brown Units 1 & 2 are shut down, there is partial ownership of a 1x1 CCGT F.05 (50%), 500 MW solar PV and 800 MW wind are installed, and 30 MW of combined heat & power is installed. Ten (10) 10MW/40MWh batteries come online in 2030. In 2035, FB Culley Units 2 & 3 are shut down, 200 MW wind and 400 MW solar PV comes online, and there is partial ownership of a 1x1 CCGT F.05 (25%).

Figure 7.8 – Stakeholder Portfolio

	(I) Stakeholder Portfolio
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2021 (6-23 MW Market Capacity) 2018-2022 (2% Energy Efficiency) 12 MW Demand Response
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire Broadway Avenue Gas (65 MW) **New** Combined Cycle Gas Turbine (50%) – 220 MW 8 MW Demand Response 2% Energy Efficiency 500 MW Solar PV 800 MW Wind Combined Heat & Power (30 MW)
2030-2036	**Retirement** Retire FB Culley 2 & 3 (360 MW) **New** Combined Cycle Gas Turbine (25%) - 110 MW 2% Energy Efficiency 400 MW Solar PV 200 MW Wind 100 MW Battery

The second stakeholder portfolio [**Stakeholder Portfolio (Cease Coal 2024)**] is similar to the previous stakeholder portfolio, except that in 2024 FB Culley Units 2 & 3 are shut down rather than in 2035. In addition in 2024, there is partial ownership of a 1x1 CCGT .05 (75%), 8x100 MW solar PV and 6x200 MW wind are installed, 30 MW of combined heat & power is installed, and ten (10) 10 MW/40 MWh batteries come online.

Figure 7.9 – Stakeholder Portfolio (Cease Coal 2024)

	(J) Stakeholder Portfolio Cease Coal 2024
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2021 (6-23 MW Market Capacity) 2018-2022 (2% Energy Efficiency) 12 MW Demand Response
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** Combined Cycle Gas Turbine (75%) - 330 MW 8 MW Demand Response 2% Energy Efficiency 800 MW Solar PV 1,200 MW Wind Combined Heat & Power (30 MW) 100 MW Battery
2030-2036	**New** 2% Energy Efficiency 100 MW Battery 2036 (3 MW Market Capacity)

7.1.3 Balanced Energy Portfolios

Economic modeling considers a wide range of theoretical possibilities, but does not necessarily account for all potential possibilities or real world outcomes, and therefore judgment must also be included in developing portfolios. In other words, an optimized portfolio may not be the best solution given future risks and uncertainties. In order to test a wide range of possible portfolios, Vectren included a business as usual portfolio and developed several balanced energy mix portfolios to be tested in the risk analysis.

The **Business as Usual Portfolio** represents a continuation of the current configuration of Vectren coal generating assets supplemented by market capacity purchases and a small measure of demand response (4 MW) 2020-2024. In 2024, a 1xF-class SCGT with an annual base load capacity of 220 MW comes online. Apart from small market capacity purchases in 2035-2036, the portfolio sees only minimal changes after the SCGT capacity comes online.

Figure 7.10 – Business as Usual Portfolio

	(A) Business as Usual (Continue Coal)
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4MW Solar 2020-2022 (60-63 MW Market Capacity) 12 MW Demand Response CCR Compliance at Brown & Culley
2023-2029	**Retirement** Retire Broadway Avenue Gas (65 MW) **New** 8 MW Demand Response 2023 (60 MW Market Capacity) Simple Cycle Gas Turbine (220 MW) **Upgrade** ELG Compliance at Brown & Culley
2030-2036	**New** 2035-2036 (4-9 MW Market Capacity)

The **FBC3, Fired Gas, & Renewables Portfolio** is characterized by market capacity purchases that occur 2020-2023, as well as blocks of energy efficiency at 1% (2018-2020), 0.75% (2021-2026), and 0.5% (2027-2036). AB Brown Units 1 & 2 as well as FB Culley Unit 2 are shut down (FB Culley Unit 3 continues) and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). 50 MW of wind and 9 MW of solar come online in 2027.

Figure 7.11 – FBC3, Fired Gas, & Renewables Portfolio

	(K) FB Culley 3, Fired Gas, & Renewables
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2022 (42-47 MW Market Capacity) 2018-2020 (1.0% Energy Efficiency) 2021-2022 (0.75% Energy Efficiency) **Upgrade** CCR Compliance for Culley 3
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 Retire Broadway Avenue Gas (65 MW) **New** 4 MW Demand Response Combined Cycle Gas Turbine (889 MW) 2023 (37 MW Mkt Capacity) 50 MW Wind 9 MW Solar 2023-2026 (0.75% Energy Efficiency) 2027-2029 (0.50% Energy Efficiency) **Upgrade** ELG Compliance for Culley 3
2030-2036	**New** 0.50% Energy Efficiency

The **FBC3, Fired Gas, Early Solar, & EE Portfolio** is similar to the previous portfolio, except that market capacity purchases are lower through 2023 and 50 MW of solar comes online in 2019. AB Brown Units 1 & 2 as well as FB Culley Unit 2 are shut down (FB Culley Unit 3 continues) and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). In addition, there are no renewable additions in 2027 as in the previous portfolio.

Figure 7.12 – FBC3, Fired Gas, Early Solar, & EE Portfolio

	(L) FB Culley 3, Fired Gas, Early Solar, & Energy Efficiency
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 54 MW Solar 2020-2022 (23-28 MW Market Capacity) 2018-2020 (1.0% Energy Efficiency) 2021-2022 (0.75% Energy Efficiency) **Upgrade** CCR Compliance for Culley 3
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 Retire Broadway Avenue Gas (65 MW) **New** Combined Cycle Gas Turbine (889 MW) 2023-2026 (0.75% Energy Efficiency) 2027-2029 (0.50% Energy Efficiency) 22 MW Market Capacity **Upgrade** ELG Compliance for Culley 3
2030-2036	**New** 0.50% Energy Efficiency

The **FBC3, Unfired Gas .05, Early Solar, EE, & Renewables Portfolio** is similar to the previous portfolio, except that market capacity purchases are lower through 2023 and 4 MW of demand response is seen through 2024. AB Brown Units 1 & 2 as well as FB Culley Unit 2 are shut down (FB Culley Unit 3 continues) and replaced by a 2x1 F-class CCGT at AB Brown with an unfired annual base load capacity of 700 MW. Beginning in 2030, market capacity purchases and solar power plants help to meet future demand requirements.

Figure 7.13 – FBC3, Unfired Gas .05, Early Solar, EE, & Renewables Portfolio

	(M) FB Culley 3, Unfired Gas .05, Early Solar, Energy Efficiency, & Renewables
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** 12 MW Demand Response Energy Efficiency Plan 2016-2017 54 MW Solar 2020-2022 (11-24 MW Market Capacity) 2018-2020 (1.0% Energy Efficiency) 2021-2022 (0.75% Energy Efficiency) **Upgrade** CCR Compliance for Culley 3
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 (90 MW) Retire Broadway Avenue Gas (65 MW) **New** 8 MW Demand Response 2023 (5 MW Market Capacity) Combined Cycle Gas Turbine (700 MW) 2023-2026 (0.75% Energy Efficiency) 2027-2029 (0.50% Energy Efficiency) **Upgrade** ELG Compliance for Culley 3
2030-2036	**New** 118 MW Solar 2030-2036 (2-10 MW Market Capacity) 0.50% Energy Efficiency

The **Unfired Gas Heavy with 50 MW Solar in 2019 Portfolio** includes market capacity purchases 2020-2022, 4 MW of DR each year 2020-2024, and blocks of energy efficiency at 1% (2018-2036). 50 MW of solar comes online in 2019. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by a 2x1 F-class CCGT at AB Brown with an unfired annual base load capacity of 700 MW and a 1xF-class SCGT with an annual base load capacity of 220 MW. Some market capacity purchases and a significant amount of solar capacity installations begin in 2025 and continue through 2036. Total solar capacity through 2036 equals 272 MW.

Figure 7.14 – Unfired Gas Heavy with 50 MW Solar in 2019 Portfolio

	(N) Unfired Gas Heavy with 50 MW Solar in 2019
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** 12 MW Demand Response Energy Efficiency Plan 2016-2017 54 MW Solar 2020-2022 (7-24 MW Market Capacity) 2018-2022 (1.0% Energy Efficiency)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 2025-2029 (3-10 MW Market Capacity) 8 MW Demand Response Combined Cycle Gas Turbine (700 MW) Simple Cycle Gas Turbine (220 MW) 118 MW Solar 1.0% Energy Efficiency
2030-2036	**New** 2030-2036 (3-9 MW Market Capacity) 100 MW Solar 1.0% Energy Efficiency

The **Gas with Renewables Portfolio** is similar to the previous portfolio, except that in 2024 an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking) comes online. 331 MW of solar capacity is installed throughout the forecast period.

Figure 7.15 – Gas with Renewables Portfolio

	(O) Gas Portfolio with Renewables
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** 12 MW Demand Response Energy Efficiency Plan 2016-2017 54 MW Solar 2020-2022 (3-24 MW Market Capacity) 2018-2022 (1.0% Energy Efficiency)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 2025-2029 (2-9 MW Market Capacity) 8 MW Demand Response Combined Cycle Gas Turbine (889 MW) 168 MW Solar 1.0% Energy Efficiency
2030-2036	**New** 2030-2034 (4-10 MW Market Capacity) 109 MW Solar 1.0% Energy Efficiency

7.2 EVALUATE PORTFOLIO PERFORMANCE

7.2.1 Uncertainty (Risk) Analysis

The process for addressing uncertainty in long-term resource planning studies requires an integrated framework that takes into account markets for natural gas, coal, oil, and other fuels as well as capital costs for new generation (both fossil-fuel units and renewables) and supply/demand dynamics affected by environmental regulations and uncertainties around these regulations. To capture this variability of market conditions, Pace Global employed a stochastic analysis that provides a wide range of potential market outcomes for the study-period. These outcomes include variables such as energy prices, portfolio costs, and revenues from specific generation assets.

7.2.1.1 Model Description

AURORAxmp was used as the primary tool for conducting Vectren's risk assessment. AURORAxmp is an industrial standard chronological unit commitment and dispatch model with extensive presence throughout the electric power industry. The model uses a state of the art, mixed integer linear programing approach (MILP) to capture details of power plant and transmission network operations while observing real world constraints, such as emission reduction targets, transmission and plant operation limitations, renewable energy availability and mandatory portfolio targets. It is widely used by electric utilities, consulting agencies, and other stakeholders to forecast generator performance and economics, develop Integrated Resource Plans (IRP), forecast power market prices, and assess detailed impact of regulations and market changes affecting the electric power industry. Key inputs to the model include load forecasts, power plant costs and operating characteristics (e.g. heat rates), fuel costs, fixed and variable operating costs, outage rates, emission rates as well as capital costs. The model is able to assess the potential performance and capital cost of existing and perspective generation technologies and resources, and make resource addition and retirement decisions for economic, system reliability, and policy compliance reasons on a utility system, regional or nationwide scale as needed. Outputs of the

model include plant generation, gross margin, emissions, and a variety of other metrics as needed.

Pace Global has used AURORA for well over 15 years as its primary model for asset valuation, power market forecast, and IRPs. The model is able to analyze portfolio risks by assessing portfolio performance across 200 different future market outlooks. Pace Global has developed a sophisticated stochastic framework to ensure that these future market outlooks reflect both relevant historic volatility in key market drivers and cross relationships between different market drivers. Pace Global has also developed modules to simulate the different operating characteristics of ISOs across the country. For this reason it is one of the most comprehensive, reliable and flexible tools in the market for conducting IRPs. Pace Global has successfully conducted numerous IRPs for many utilities across the country, it has gained wide acceptance before energy company managements, stakeholder groups and PUCs.

In order to perform the stochastic analysis, a set of probability distributions are required for key market driver variables. These include probabilistic distributions for demand growth (load), fuel costs (natural gas and coal), environmental compliance costs (carbon), and capital costs.

7.2.1.1.1 Load Stochastics

To account for variations in electricity demand stemming from economic growth, weather, and energy efficiency and demand side management measures, Pace Global developed stochastics around the load growth expectations for the Vectren control area and the neighboring ISO zones. Pace Global's long-term load forecasting process is a two-step process that captures both the impact of historical load drivers such as economic growth and variability of weather (parametric step) and the possible disruptive impacts of energy efficiency penetration (quantum step) in constructing the average and peak demand outlook. This process is explained in detail in the Technical Appendix 10.5 Risk Appendix. Pace Global benchmarked the projections against MISO-

sponsored load forecasting studies that are conducted by independent consultants and institutions and then released into the public domain.

7.2.1.1.2 Gas Stochastics

Pace Global developed natural gas stochastic distributions for Henry Hub and other basis points in MISO and elsewhere. These stochastic distributions are based on the base case view of natural gas prices with probability bands developed based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility. To estimate future volatility, the volatility of the last 30 months is applied to 2016-2018, the volatility from 2011-2015 is applied to 2016-2025, and the volatility from 2005-2015 is applied to 2026-2035. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95th percentile probability bands are driven by increased gas demand (most likely due to coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization down as well as little to no environmental legislation around power plant emissions.

7.2.1.1.3 Coal Stochastics

Pace Global developed coal price stochastic distributions for CAPP, NAPP, ILB and PRB basins. These stochastic distributions are based on a base case view of coal prices with probability bands developed based on a combination of historical volatility and mean reversion parameters. It should be noted that the majority of coal contracts in the U.S. are bilateral and only about 20 percent are traded on the NYMEX. The historical data set that is used to calculate the parameters is comprised of the weekly traded data reported in NYMEX.

7.2.1.1.4 Emissions Stochastics

Pace Global developed uncertainty distributions around carbon compliance costs, which were used in the power dispatch modeling to capture the inherent risk associated with

regulatory compliance requirements. The technique to develop carbon costs distributions, unlike the previous variables, is based on "expert-opinion"-based projections, as there are no historical data sets to estimate the parameters for developing carbon costs distributions.

7.2.1.1.5 Capital Cost Stochastics

Pace developed the uncertainty distributions for the cost of new entry units by technology types, which was used in the Aurora dispatch model for determining the economic new builds based on market signals. The methodology of developing the capital cost distributions is a two-step process: (1) a parametric distribution based on a base case view of future all-in capital costs, historical costs and volatilities, and a sampling of results to develop probability bands around the base case; and (2) a quantum distribution that captures the additional uncertainty with each technology that factors in learning curve effects, improvements in technology over time, and other uncertain events.

7.2.1.1.6 Cross-Commodity Stochastics

Pace Global has implemented a distinct process to capture the cross-commodity correlations into the stochastic processes, which is a separate stochastic process from those for gas, coal and CO_2. At a high level, the feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators. Pace Global conducted fundamental analysis to define the relationship between gas-coal dispatch cost and demand. The dispatch cost of gas and coal was calculated from the fuel stochastics and CO_2 stochastics, along with generic assumptions for VOM. Where the gas-coal dispatch differential changes significantly enough to affect demand, gas demand from the previous year was adjusted to reflect the corresponding change in demand. A gas price delta was then calculated based on the defined gas demand. This gas price delta was then added to the gas stochastic path developed from historic volatility to calculate an integrated CO_2 and natural gas stochastic price.

7.2.1.2 Results

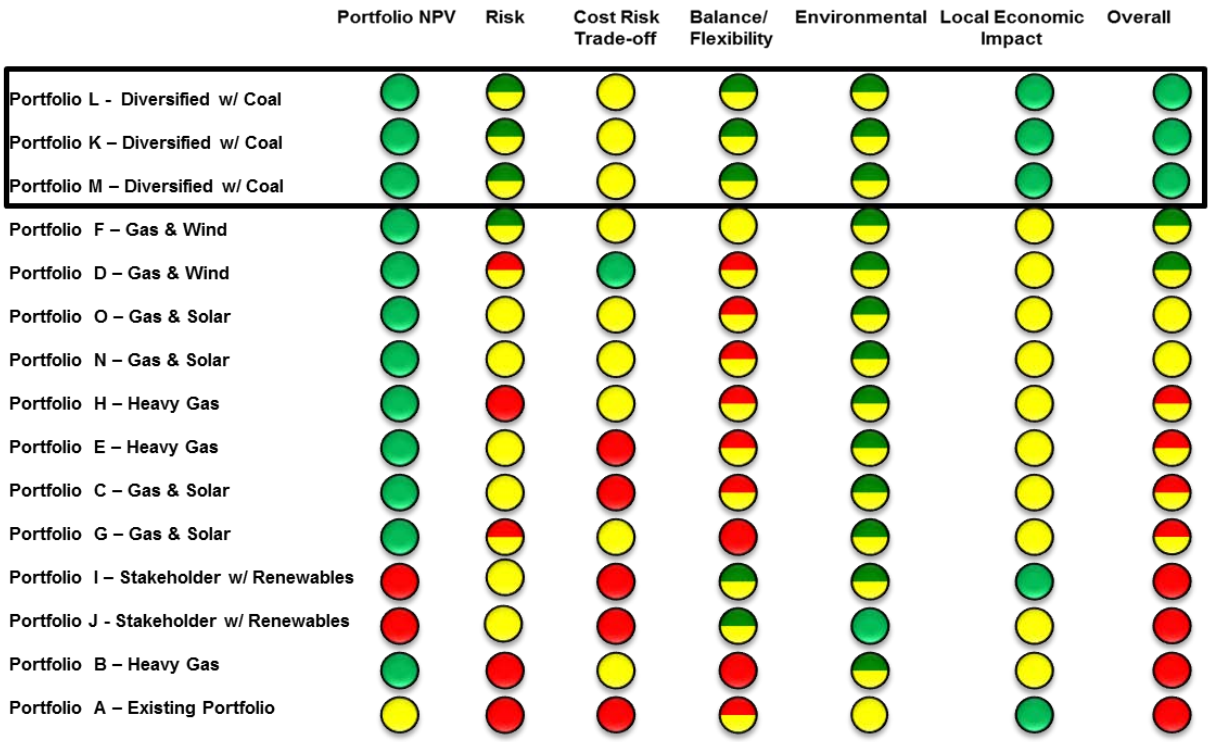
7.3 RISK ANALYSIS SUMMARY OF RESULTS

As summarized in an earlier section, Pace Global conducted a risk analysis on 15 portfolios. The analysis subjects each portfolio to 200 iterations (future market and regulatory outcomes). Then portfolios were ranked by each group of key criteria and associated metrics. The best performers in each metric were given a green color and the worst were given a red color; yellow was also shown as caution within a given metric.

Figure 7.16 summarizes the rankings for each metric. This figure shows that the diversified portfolios with coal resources performed better than the other portfolios across all of the metrics.

The recommended portfolio (Portfolio L) adopted renewables earlier than the other diversified portfolios with coal in them.

Figure 7.16 – IRP Portfolio Balanced Scorecard

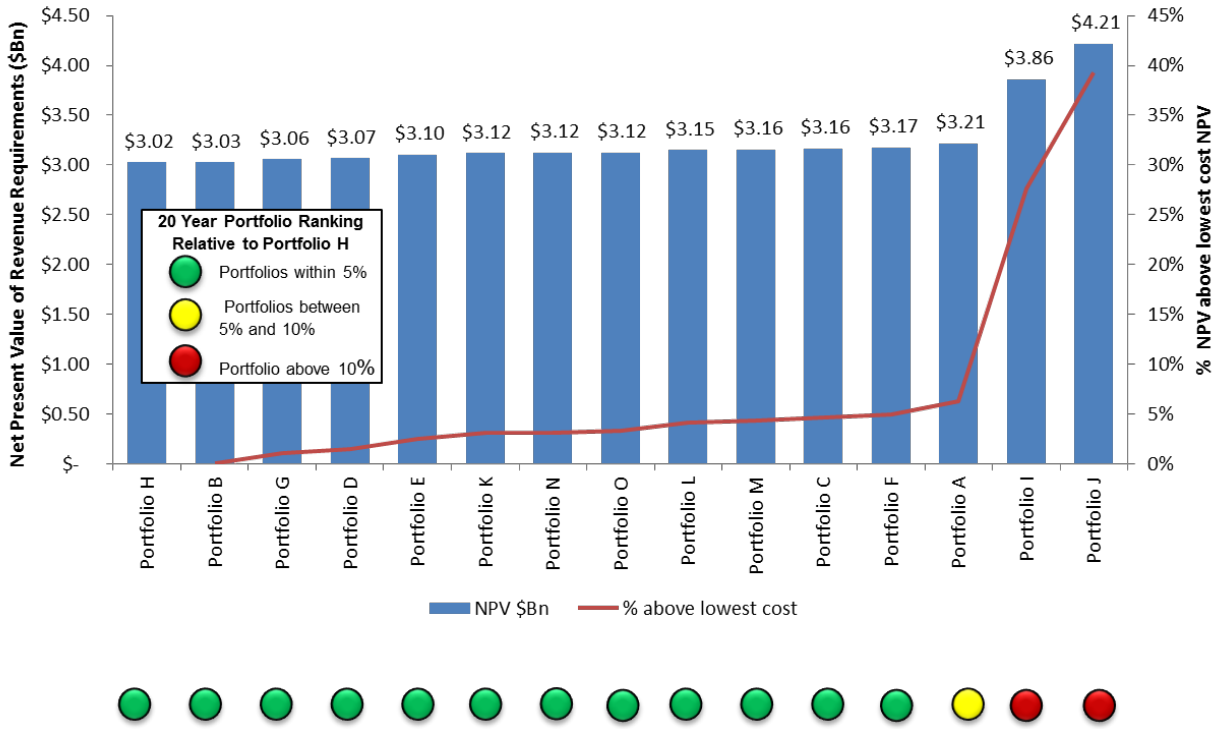


The sections below build up the metrics one at a time.

7.3.1 Customer Rates

The portfolio with the lowest mean or average costs across all 200 iterations will facilitate lower customer rates than other portfolios. The portfolios that were within 5% of the portfolio with the lowest expected cost (the net present value of revenue requirements) were given a green color, and the portfolios that were 10% or more expensive than the lowest cost portfolio were given a red color.

Figure 7.17 – IRP Modeling – 20-Year NPV Ranking



7.3.2 Risks

Four different risks were considered as part of the "Risk" metric.

One measure of risk is the volatility of the portfolio cost across the 200 iterations. The most commonly used measure of volatility is the standard deviation of the mean. The portfolios whose standard deviations of the mean were within 10% of the least volatile portfolio were given a green color. The portfolios that had standard deviations 15% or more than the lowest portfolio were given a red color. The recommended portfolio (Portfolio L) received a green color. Please see slide 50 from the November 29th Public Stakeholder meeting found in Attachment 3.1 Stakeholder Materials for more information.

The second measure of risk is exposure to volatilities in the wholesale energy market prices. The portfolio with the lowest average purchases from the market is less subject to market price volatility. When looking at the range of market purchases, those with

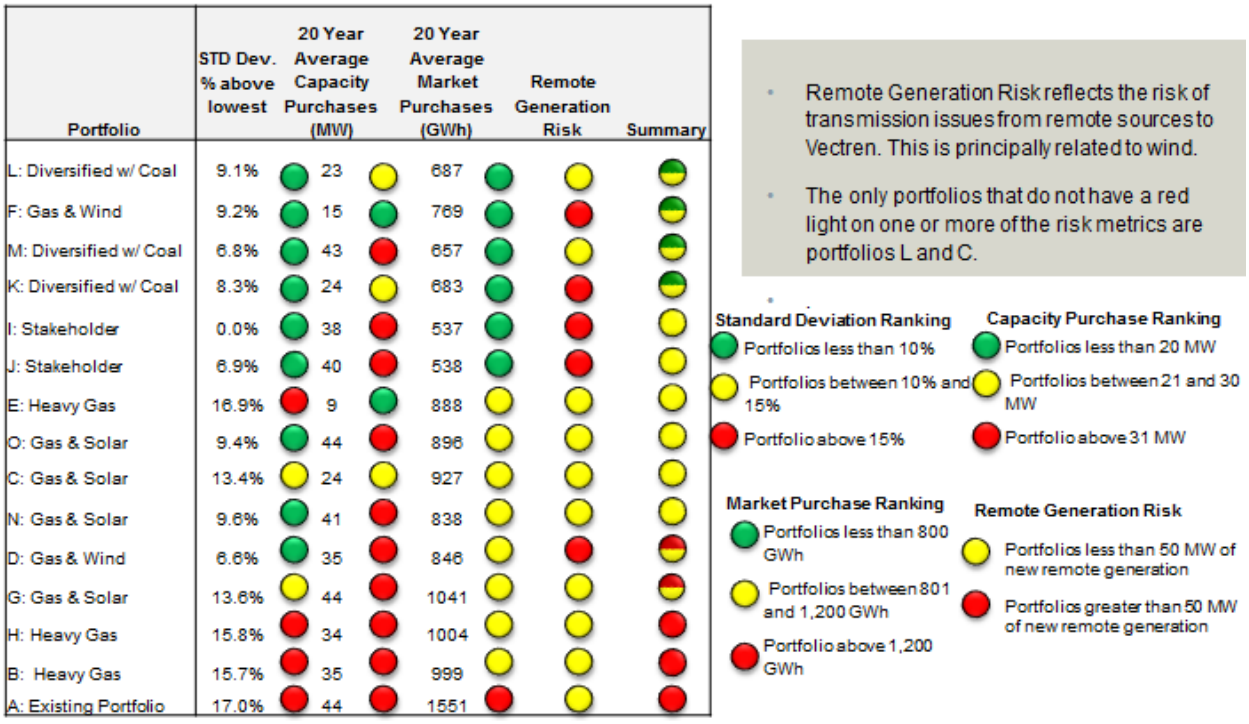
less than 800 GWhs per year on average were given a green color and those above 1,200 GWhs were given a red color. Again, Portfolio L received a green color rating. Please see slide 52 from the November 29th Public Stakeholder meeting found in Attachment 3.1 Stakeholder Materials for more information.

The third measure assesses the potential exposure to MISO capacity markets. Although each portfolio is designed to meet MISO reserve margin targets under reference case conditions, they each may fall short if demand growth is higher than expected. The average number of additional capacity purchases across all 200 iterations was computed to see which needed the most incremental capacity purchases. Portfolios purchasing less than 20 MW per year on average received a green color and those above 35 MW per year received a red color. The recommended portfolio received a yellow color. Please see slide 51 from the November 29th Public Stakeholder meeting found in Attachment 3.1 Stakeholder Materials for more information.

The fourth and final risk measure was remote generation risk. Portfolios with generation assets located away from Vectren's service territory are exposed to greater risk of transmission congestion and outages. Portfolio L has limited susceptibility to remote generation risk.

The overall risk measure is the average of the four colors. All three of the diversified with coal portfolios (K, L, and M) were at the top of the group on the four risk measures.

Figure 7.18 – Risk Metric Summary

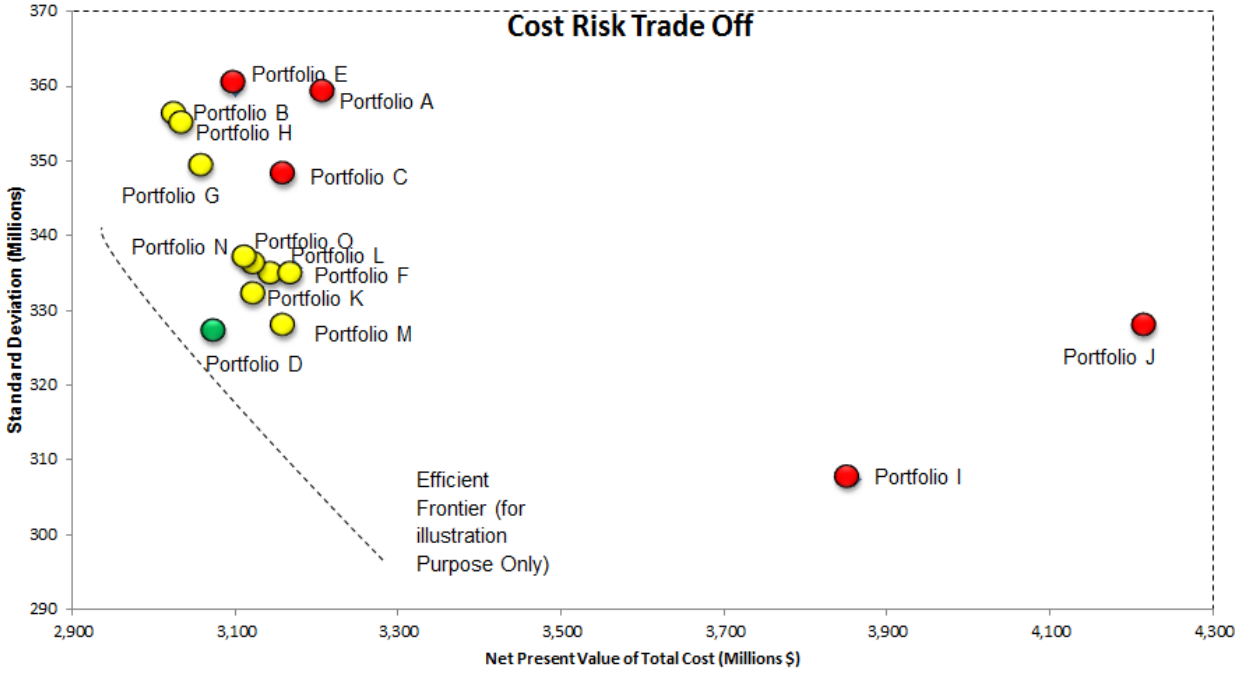


Portfolio	STD Dev. % above lowest	20 Year Average Capacity Purchases (MW)	20 Year Average Market Purchases (GWh)	Remote Generation Risk	Summary
L: Diversified w/ Coal	9.1%	23	687		
F: Gas & Wind	9.2%	15	769		
M: Diversified w/ Coal	6.8%	43	657		
K: Diversified w/ Coal	8.3%	24	683		
I: Stakeholder	0.0%	38	537		
J: Stakeholder	6.9%	40	538		
E: Heavy Gas	16.9%	9	888		
O: Gas & Solar	9.4%	44	896		
C: Gas & Solar	13.4%	24	927		
N: Gas & Solar	9.6%	41	838		
D: Gas & Wind	6.6%	35	846		
G: Gas & Solar	13.6%	44	1041		
H: Heavy Gas	15.8%	34	1004		
B: Heavy Gas	15.7%	35	999		
A: Existing Portfolio	17.0%	44	1551		

7.3.3 Cost-Risk Tradeoff

Cost and Risk tradeoff relates two variables, expected costs and the standard deviation of cost, to provide a metric of whether a portfolio hedges risk in a cost effective manner. The following graph shows some portfolios have both higher expected costs and higher standard deviations than other portfolios (receiving a red color). Others, like the two stakeholder portfolios, have very high expected costs, so high that they far exceeded the benefit of these portfolios' lower standard deviation. The recommended portfolio (Portfolio L) was given a yellow color.

Figure 7.19 – Portfolio Standard Deviation Risk (vertical axis) vs. Expected Cost (horizontal axis) Tradeoff



7.3.4 Environmental Issues

All of the portfolios will easily meet the requirements of the Clean Power Plan. Nearly all portfolios are approximately 15% or more below the required level of carbon reductions. Portfolio L will reduce carbon levels by over 45%. Moreover, nearly all the portfolios will reduce both SO_2 and NO_X levels by over 80%. While the stakeholder portfolios have the greatest reductions, all other Portfolios received a yellow/green color. Please see slides 63-65 from the November 29th Public Stakeholder meeting found in Attachment 3.1 Stakeholder Materials for more information.

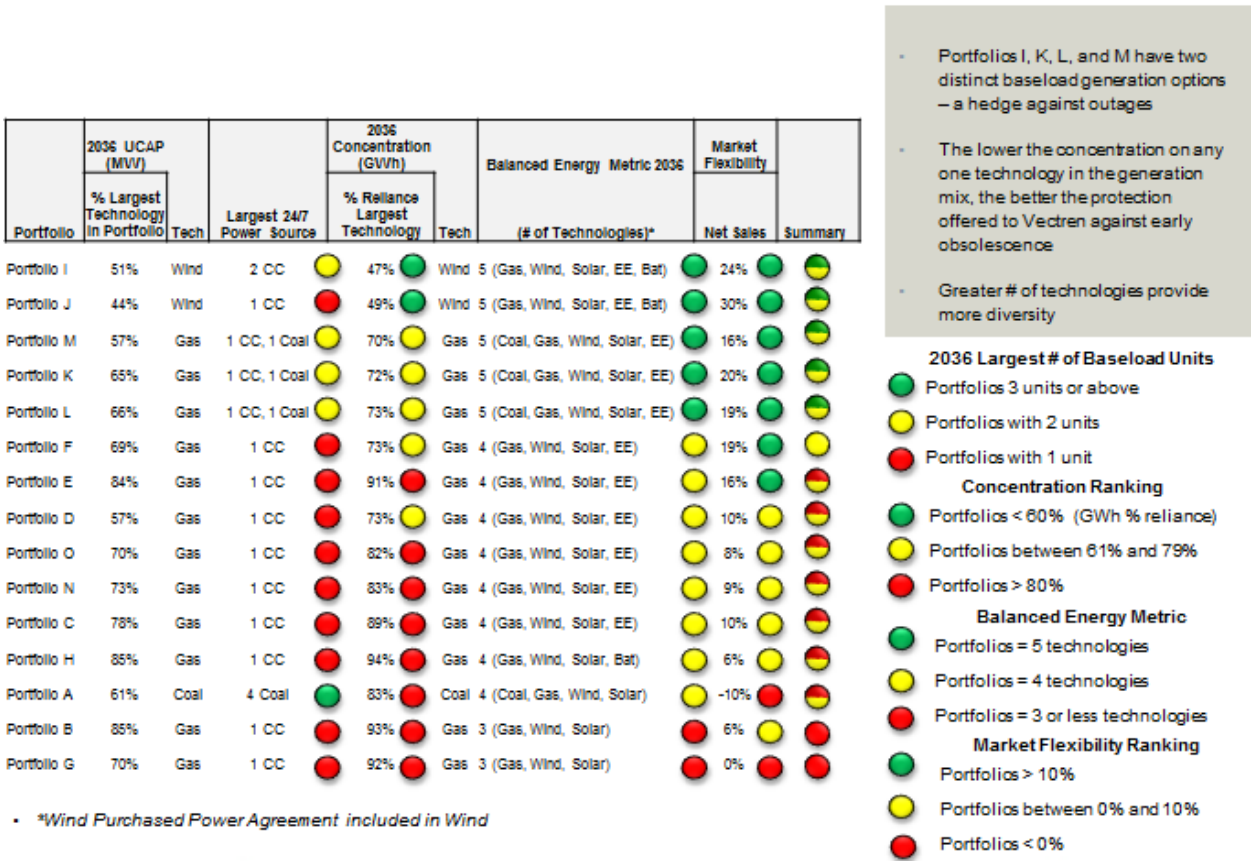
7.3.5 Balance and Flexibility

Balance and flexibility are important objectives to ensure that Vectren has a diverse generation mix that does not rely too heavily on the economics and viability of one technology or one site. In addition, portfolios with the greatest number of technologies

are ranked higher than those with fewer numbers. Finally portfolios with more net sales have the flexibility to adapt to unexpected breakthroughs in technology.

The recommended portfolio (Portfolio L) is among the best portfolios considering the number of technologies (five) relied upon. It also has one of the higher net sales levels.

Figure 7.20 – Balanced Energy Summary Metric



Portfolio	2036 UCAP (MW) % Largest Technology in Portfolio	Tech	Largest 24/7 Power Source	2036 Concentration (GWh) % Reliance Largest Technology	Tech	Balanced Energy Metric 2036 (# of Technologies)*	Market Flexibility Net Sales	Summary
Portfolio I	51%	Wind	2 CC	47%	Wind	5 (Gas, Wind, Solar, EE, Bat)	24%	
Portfolio J	44%	Wind	1 CC	49%	Wind	5 (Gas, Wind, Solar, EE, Bat)	30%	
Portfolio M	57%	Gas	1 CC, 1 Coal	70%	Gas	5 (Coal, Gas, Wind, Solar, EE)	16%	
Portfolio K	65%	Gas	1 CC, 1 Coal	72%	Gas	5 (Coal, Gas, Wind, Solar, EE)	20%	
Portfolio L	66%	Gas	1 CC, 1 Coal	73%	Gas	5 (Coal, Gas, Wind, Solar, EE)	19%	
Portfolio F	69%	Gas	1 CC	73%	Gas	4 (Gas, Wind, Solar, EE)	19%	
Portfolio E	84%	Gas	1 CC	91%	Gas	4 (Gas, Wind, Solar, EE)	16%	
Portfolio D	57%	Gas	1 CC	73%	Gas	4 (Gas, Wind, Solar, EE)	10%	
Portfolio O	70%	Gas	1 CC	82%	Gas	4 (Gas, Wind, Solar, EE)	8%	
Portfolio N	73%	Gas	1 CC	83%	Gas	4 (Gas, Wind, Solar, EE)	9%	
Portfolio C	78%	Gas	1 CC	89%	Gas	4 (Gas, Wind, Solar, EE)	10%	
Portfolio H	85%	Gas	1 CC	94%	Gas	4 (Gas, Wind, Solar, Bat)	6%	
Portfolio A	61%	Coal	4 Coal	83%	Coal	4 (Coal, Gas, Wind, Solar)	-10%	
Portfolio B	85%	Gas	1 CC	93%	Gas	3 (Gas, Wind, Solar)	6%	
Portfolio G	70%	Gas	1 CC	92%	Gas	3 (Gas, Wind, Solar)	0%	

- *Wind Purchased Power Agreement included in Wind

- Portfolios I, K, L, and M have two distinct baseload generation options – a hedge against outages
- The lower the concentration on any one technology in the generation mix, the better the protection offered to Vectren against early obsolescence
- Greater # of technologies provide more diversity

2036 Largest # of Baseload Units
- Portfolios 3 units or above
- Portfolios with 2 units
- Portfolios with 1 unit

Concentration Ranking
- Portfolios < 60% (GWh % reliance)
- Portfolios between 61% and 79%
- Portfolios > 80%

Balanced Energy Metric
- Portfolios = 5 technologies
- Portfolios = 4 technologies
- Portfolios = 3 or less technologies

Market Flexibility Ranking
- Portfolios > 10%
- Portfolios between 0% and 10%
- Portfolios < 0%

7.3.6 Local Economic Impact

The last metric is local economic impact to the community. This includes local output reductions and tax losses if local generation is closed. In addition, construction additions and operation of replacement generation was considered. Portfolio L has the lowest negative impact among portfolios. The full economic impact report can be found in Technical Appendix Attachment 7.4 Economic Impact Study – Economic Ripple Effects of Diversifying Power Generation Portfolio.

Figure 7.21 – Local Economic Impact

Closing FB Culley 3 by 2024 would have an adverse economic impact to the community, particularly hard hit Warrick County*

- Total 1-year Output Impact = $145 million
- Total 1-year State and Local Tax Impact = $7 million, of which Vectren's property taxes from Culley 3 alone currently contribute approximately $350 thousand dollars annually to Warrick County School Corp.
- Total Jobs Impact = 271, which includes 82 direct job losses at the plant

Building and operating a combined cycle gas plant within Vectren's service territory would minimize the economic impact to the community of closing the AB Brown Plant by 2024

- Total Output Impact of construction = $950 million
- Total Output Impact of operating the plant = $50 million per year

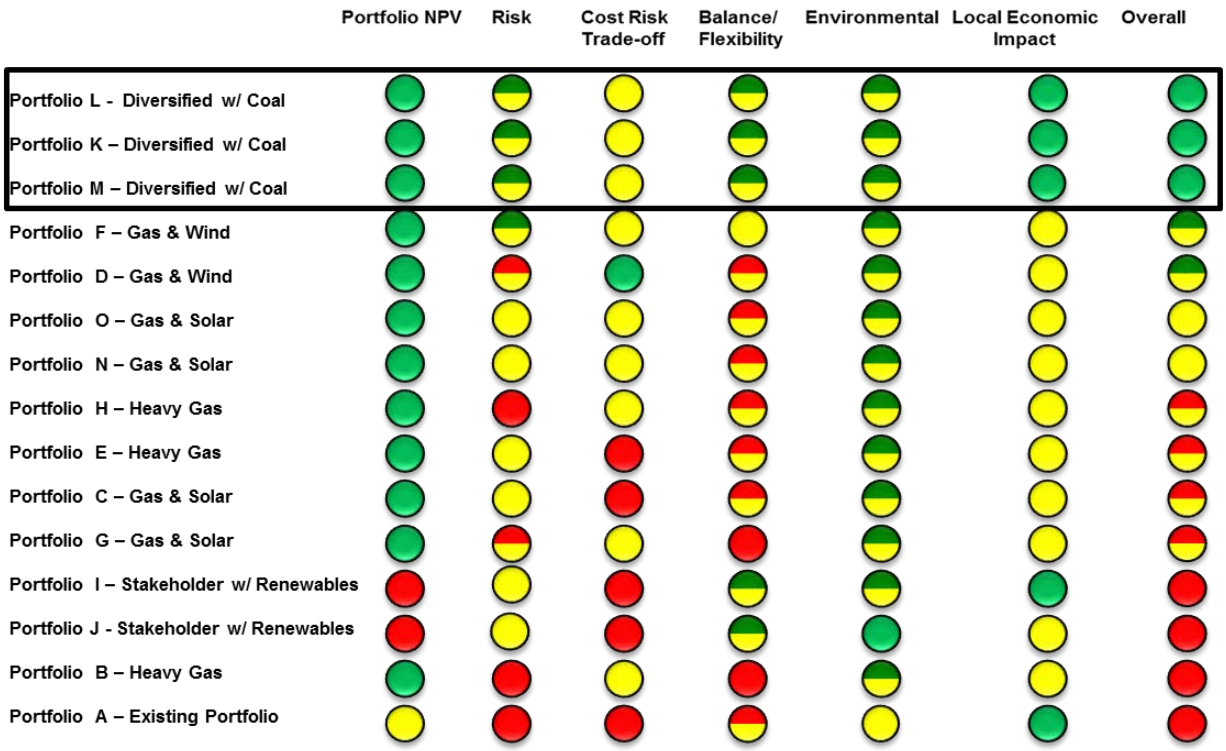
*Alcoa closed its smelter operation in the spring of 2016. The impact is compounded by FB Culley 2 by 2024. Economic impact study conducted by professors of economics and finance at the University of Evansville. Total economic impact based on an Economic Impact Study using IMPLAN social accounting system. Total impact includes direct, indirect, and induced effects.

SECTION 8
IRP RESULTS AND RECOMMENDATION

8.1 SCORECARD COMPARISON

Balanced portfolios L, K, and M, the Diversified with Coal Portfolios, perform best across all metrics, as shown below in Figure 8.1. Of the three diversified portfolios, Portfolio L has early renewables and low cost, highly efficient peaking capacity to back up variable renewable resources, mitigate capacity market risk, and allow for economic development opportunities.

Figure 8.1 – IRP Portfolio Balanced Scorecard



8.2 PREFERRED PORTFOLIO RECOMMENDATION

The preferred portfolio L provides a number of benefits to Vectren customers and other stakeholders:

- Is among the best performing portfolios across multiple measures on the balanced scorecard
- Is among the lower cost portfolios (within 4% of the lowest cost portfolio)

- Leads to a lower carbon future – Achieves almost 50 percent reduction in carbon (base year 2012) by 2024, which exceeds the Clean Power Plan (CPP) requirements – carbon emissions reduction from 2005 levels would be almost 60 percent
- Brings renewables into the portfolio by 2019. Renewables and ongoing Energy Efficiency account for approximately 20% of total capacity by 2036
- Provides low-cost peaking generation through duct-firing that enhances opportunities for economic development and wholesale sales, which lowers customer bills
- Avoids reliance on a single fuel and provides a balanced mix of coal, gas, and renewables. While reliance on gas is significant, a duct-fired plant would allow for back up of further variable renewable resources in the long term
- Is among the best portfolios in terms of limiting negative economic impact from job loss and local tax base. University of Evansville professors concluded that the economic ripple effect of losing 82 FB Culley jobs equates to 189 additional job losses in the community. Total state and local tax impact would be approximately 7 million dollars annually. Moreover, to the extent a new gas unit is built at the AB Brown site, over 100 total jobs are expected to be retained in the community. Total state and local tax impact would be approximately 4 million dollars annually.
- Reduces dependence on coal-fired generation over time and provides flexibility to adapt to changes in technology
- Takes advantage of tax incentives for solar power plants

8.2.1 Description of the Portfolio

8.2.1.1 Retirements

Vectren will be replacing a large portion of its aging generating fleet under the preferred plan. The preferred portfolio retires a significant amount of coal generation, including: Brown Units 1 & 2 and FB Culley Unit 2. While the Brown units are newer than FB

Culley 3, they have more expensive scrubber technology used to scrub SO_2 from the air. Vectren invested early in this clean coal technology on Brown units 1 and 2 in 1979 and 1986, respectively. The AB Brown SO_2 scrubbers are of a design known as dual alkali scrubbers. The FB Culley forced oxidation SO_2 scrubber was retrofitted years later and has better SO_2 removal efficiency with significantly lower operating costs when compared to the AB Brown dual alkali scrubbers. It should be noted that the boiler and turbine generator actually represent only a portion of the equipment required for a modern environmentally compliant coal plant. Successful coal unit operation relies heavily on extensive pollution control equipment. In short, environmental compliance is projected to be less expensive at Culley than Brown.

Additionally, the preferred plan has additional benefits in regard to having generation located on both sides of the Evansville load. If all generation were retired on one side of the system, voltage regulation issues would arise on the side of the system that was without generation. Should the combined cycle plant be built on the west side of the system, Culley 3 can help provide this support for the east side of the system.

The preferred portfolio also retires several small, inefficient gas peaking units due to age, including: Broadway Avenue Gas Generating Station 1 (BAGS 1) in 2019, Northeast 1 & 2 gas peaking units in 2019, and BAGS 2 in 2025. The preferred plan calls for the new combined cycle gas turbine to be duct-fired, which will replace older, inefficient peaking capacity with much more efficient peaking capability. Depending on set up, duct-firing can provide approximately 200 MWs (Installed Capacity) of efficient peaking capacity capability through gas burners located within the heat recovery steam generator. These burners can be fired to generate more power during times of high demand. This technology is about half of the cost of a comparable simple cycle gas turbine.

8.2.1.2 Existing

The preferred portfolio continues use of FB Culley 3, which is Vectren's most efficient coal unit. This 270 MW unit is controlled for NO_X with an SCR. It is controlled for SO_2 with an FGD. Additionally, it has a fabric filter to remove particulate matter and is controlled for mercury and SO_3. It should also be noted that the FB Culley SO_2 FGD is a different design than the FGDs on the AB Brown coal units. The FB Culley FGD achieves more efficient SO_2 removal at significantly lower operating costs than the FGD at AB Brown. Further, most of the FGD byproduct at FB Culley is beneficially reused in the manufacture of drywall, which also reduces costs when compared to landfilling the AB Brown FGD byproduct. Vectren studies say that the going forward environmental compliance costs at FB Culley are expected to be lower than at AB Brown. And lastly, maintaining generating facilities on both sides of Evansville is desirable from a reliability and voltage regulation perspective.

8.2.1.3 Renewables

Solar photovoltaic (PV) technology is key to providing future, clean energy as part of a balanced, economical portfolio. However, PV is relatively new as a source of utility-scale generation. Each potential project poses unique challenges including site-selection and land-use competition, the amount of solar irradiance available for conversion to electricity, transmission and interconnection design, and component-level configuration of the plant. Due to the complexity of these projects, energy companies take an incremental approach to solar plant development, gaining proficiencies in these resource options along the way and unlocking the greatest value from future renewable energy installations for the communities in which they serve.

Vectren plans to explore a variety of solar PV arrangements while providing universal solar power for its customers from installations in rural as well as rooftop settings. The preferred portfolio calls for a 4 MW solar plant by 2018. This is representative of several, smaller, energy company-owned and operated projects that are expected to be in place by this time, including a 2 MW solar power plant with a 1 MWh battery storage

system. Additionally, Vectren is in talks with the City of Evansville on joint projects to be finalized in the first quarter 2017, and Vectren is in on-going discussions to develop other potential projects.

Vectren's plans to integrate up to 54 MWs of solar power before tax incentives expire in 2020. The solar projects are designed to afford Vectren South and its customers an opportunity to make a meaningful step to integrating solar power into Vectren South's integrated resource portfolio. Vectren plans 50 MW of solar in 2019, which corresponds with clean energy tax incentives. Projects meeting the ITC Requirements by December 31, 2019 are eligible for 30% tax credit, helping to offset comparatively higher cost of solar generation to other resources. Timing of this plant may change should these incentives not be available. After 2020, the sustained growth rate of solar power penetration is uncertain due to policy, technological, economic, and a variety of other factors. However, in the recent release of its 2016 Standard Scenarios Report, the National Renewable Energy Laboratory cited solar PV, especially universal solar power plants, as a growing contributor of renewable energy generation. Vectren's preferred portfolio positions the company to efficiently adapt to the evolving energy mix while passing the benefits of current tax incentives on to its customers.

8.2.1.4 Energy Efficiency

The preferred portfolio continues energy efficiency programs throughout the next 20 years to help cost effectively serve Vectren customers, providing them with tools to help manage their energy bills. The preferred portfolio includes energy efficiency equivalent to 1% of eligible sales annually for years 2018 through 2020. Vectren will file its 2018-2020 energy efficiency plan in the spring of 2017, which is consistent with this level.

Vectren ran several scenarios with varying future states. Three of the seven model runs selected 1% energy efficiency throughout the 20-year period, and one selected 2% energy efficiency over this time period. These alternate scenario runs helped to inform the preferred level of energy efficiency; however, judgment for reasonableness is still

necessary. Vectren included energy efficiency resources in the preferred plan that is viable and can confidently be achieved over the 20 year period (0.75% of eligible sales between 2021-2026 and 0.50% thereafter to cover incremental expected energy and demand growth). The level of energy efficiency selected in the next IRP will inform the 2021-2023 DSM filing.

8.2.2 Environmental Benefits

Vectren has reduced carbon emissions by 31% between 2005 and 2015. The preferred portfolio leads to a lower carbon future by reducing CO_2 by 46% from 2012 levels, which exceeds the Clean Power Plan requirements. Additionally, the preferred portfolio is expected to reduce SO_2 and NO_X by over 80% compared to the average of 2012-2015 levels.

A new CCGT will yield a significant reduction in air, water, and waste emissions for Vectren's generation portfolio. The ability for rapid ramp-up will allow effective back up power to renewable generation sources such as the new proposed solar projects. Additionally, a new CCGT is more efficient (requires less fuel per kilowatt hour) than a coal unit.

The preferred portfolio keeps FB Culley 3, which is controlled for multiple air pollutants. This 270 MW unit is controlled for NO_X with an SCR. It is controlled for SO_2 with an FGD. Additionally, it has a fabric filter to remove particulate matter and is controlled for mercury and SO_3. The unit has dry fly ash handling which allows for the recycling of the fly ash at a cement kiln in addition to the synthetic gypsum (FGD solids) which goes to a wallboard manufacturer.

8.2.3 Reliability

Each of the portfolios were required to meet all of the planning (PRM) and operational (UCAP) requirements set out by the Regional Transmission Operator (MISO) under each of the screening analyses. In the case of renewable builds, the ability of Vectren

to support variable resources limited the total capacity of renewables built into any one portfolio in the near term.

In addition, too much reliance on one site or on one technology or fuel source, or too much reliance on remote sources, can expose Vectren to the risk of weather, transmission, or other risks that can at least temporarily impact reliability. These factors were carefully considered in the Energy Balance metric. The recommended Portfolio L meets all of the MISO reserve requirements, had five technologies in the capacity mix, two 24/7 baseload technologies, and no additional remote sources (beyond its existing contracts), which provides a relatively secure, reliable portfolio.

8.2.4 Cost

Expected costs over the planning horizon are one of the most important metrics that were evaluated in the risk analysis. Over 200 different scenarios (future conditions) were evaluated to fully test each of the 15 portfolios. While the selection of a combined cycle plant with duct-firing was consistently selected as part of the most economic portfolios, the majority of the 15 portfolios evaluated were within 5% of the lowest cost portfolio. The lowest cost scenarios were “heavy gas” portfolios which provided less diversity and less flexibility than the other portfolios. The recommended Portfolio L exhibited costs 4.1% higher than the lowest portfolio. Compared to this, the highest cost portfolios were the Stakeholder Portfolios, which were both over 25% higher cost than the lowest cost portfolios.

8.2.5 Benefits of a Balanced Energy Mix

In a world where the rate of technological advance is creating greater and greater levels of uncertainty, the benefits of a balanced energy mix cannot be understated. Five years ago, few predicted that the shale boom would result in low and relatively stable gas prices for the past five years. While renewable costs continue to decline, it is impossible to predict when battery storage technologies will become economic or whether it will fundamentally change the economics of base load generation. The best

way to plan in this environment is to provide a diverse portfolio, which provides natural hedges against unforeseen changes in regulations, technologies and markets. Placing too large a bet on one and only one technology with no flexibility to adapt would leave Vectren subject to unexpected changes that could result in significant stranded assets.

The recommended Portfolio L takes a balanced approach towards capturing the current promises of combined cycle plant afforded by the mainstream low gas price outlook, and retaining a hedge against new gas capital investment becoming stranded later in the relatively unlikely event of dramatic storage technology breakthrough or unexpected severe gas extraction regulation, which is diminished by retaining a modest amount of existing coal. Portfolio L further reduces exposure to the risk of relying heavily on any single technology by incorporating three additional sources of energy generation, from solar, wind, and through energy efficiency measures.

8.2.6 Flexibility

Flexibility is another important objective for Vectren's future portfolio. Prior to the 2016 presidential election, greater regulations on natural gas, tighter carbon controls, and more regulations were commonly expected. With President-Elect Trump's election, even the current regulations on the Clean Power Plan could be in jeopardy. It is clear that with the new administration, and the rate of technological advance, Vectren must position itself to be as flexible as possible. With that in mind, Vectren needs to be able to react quickly should such factors as renewable tax provisions and the regulations on coal call for changes to its portfolio composition, such as by closing its coal plants or accelerating/delaying adding renewable generation. Whether Vectren has the agility to react in a timely manner depends in part on whether Vectren's portfolio has sufficient reserve capacity to avoid excessive exposure to market volatility during the transition, when some established market hedges (plants) retire, and before new ones (plant builds) can be completed. This reserve capacity is reflected in the amount of economic generation a portfolio has available for export into the wholesale market under normal circumstances.

8.2.7 Transmission/Distribution

An assessment of Vectren's transmission system was conducted to ensure that the preferred portfolio would support continued system reliability. The analysis indicated that the system would perform well; however, certain transmission enhancements will be required to support continued reliability. A new west to east 138 kV line from the AB Brown power plant to Pigeon Creek substation to the Culley power plant will need to be constructed. Also, additional dynamic reactive power support is needed in the eastern part of system, which will require a synchronous condenser, Static Var Compensator (SVC), or an alternative reactive power source.

8.2.8 Risk

A number of risks were considered in selecting the recommended portfolio. The first risk measured was the stability of the portfolio over the 200 scenarios run. The "standard deviation" measures the variability of portfolio cost around the mean value, with a lower standard deviation representing a relatively stable portfolio considering uncertainties in load, fuel prices, capital costs, and emissions. Another risk is exposure to the market. Owned generation is a hedge against market price fluctuations, so lower market purchases reduce Vectren's exposure to market fluctuations. A third risk is tied to incremental capacity purchases that would be required to meet on-going UCAP reserve requirements. These incremental purchases are not explicitly captured in the risk metrics. The fourth metric is the risk of remote sources, which subjects capacity to greater levels of transmission and site related risks, simply by being remote to its service territory.

The recommended Portfolio L belongs to the low-to-mid group of portfolios in terms of cost standard deviation, which indicates its expected costs are relatively stable over a wide range of market conditions. It requires some of the lowest levels of energy market purchases among the portfolios examined, which further reduces Vectren's exposure to market heat rate risk. While Portfolio L has some transmission congestion risk resulting from reliance on existing remote wind contracts, it controls this risk by calling for no

further wind generation. Only in potential requirements for further capacity purchases does Portfolio L fall to the middle tier amongst all portfolios examined. But when examined together, Portfolio L is one of the best among the portfolios examined.

8.2.9 Economic Impact Analysis Results

The preferred portfolio is among the best portfolios in terms of limiting negative economic impact from job loss and local tax base. University of Evansville professors concluded that the economic ripple effect of losing 82 FB Culley jobs equates to 189 additional job losses in the community. Total state and local tax impact would be approximately seven million dollars annually. Currently, taxes from FB Culley 3 alone contribute approximately $350 thousand annually to the Warrick County School Corp. The total output impact of FB Culley 3 is $145 million annually.

Additionally, building and operating a combined cycle gas plant within Vectren's service territory would minimize the economic impact to the community of closing the AB Brown Plant by 2024. The construction of the plant is expected to produce $950 million in total economic output. Once operational, the plant is expected to have total output of $50 million annually.

8.2.10 Fuel Inventory and Procurement Planning

It is impossible to predict price fluctuations in commodity prices such as coal and natural gas. Vectren 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 in order to even out short term price fluctuations. Coal suppliers and transportation providers generally require firm commitments in regard to quantities; however, Vectren coal contracts include optionality to adjust tonnage up or down to help manage operational variability which impacts inventory levels. Currently Vectren utilizes non-firm pipeline delivery and gas storage for the existing peaking units. It is planned that the future combined cycle gas fired 24x7 generator will utilize firm pipeline supply contracts.

SECTION 9
SHORT TERM ACTION PLAN

9.1 DIFFERENCES BETWEEN THE LAST SHORT TERM ACTION PLAN FROM WHAT TRANSPIRED

Consistent with its commitment in the 2014 Short Term Action Plan, Vectren has continued monitoring changes in inputs to its integrated resource planning. The 2016 IRP accounts for changes that have occurred and, as a result, changes the recommended short-term action plan.

The 2014 IRP called for no additional supply side resources to meet customer needs based on reasonable assumptions made in that IRP. Accordingly, Vectren did not pursue any new supply side resources in 2014 or 2015.

The 2014 IRP did support continued energy efficiency programs designed to save 1% of eligible retail sales. Vectren proposed the 2016-2017 Electric DSM Plan to obtain approval of programs to achieve this level of savings. The Commission approved this plan on March 23, 2016 in Cause No. 44645. Consistent with the 2014 IRP, the framework for the 2016-2017 filed plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 80% eligible load.

Since 2014 gas prices have dropped and are projected to remain low and stable over the long term. Shale gas has revolutionized the industry, driving these low gas prices, and is fueling a surge in low-cost gas generation around the country. Projected gas prices were a major driver in this analysis.

Vectren's planning efforts for the 2016 IRP identified changes from the 2014 assumptions that drive different conclusions. In the ensuing two years, environmental rules (the CPP, ELG, and CCR) were finalized. The final ELG and CCR were more stringent than originally proposed by the EPA. The stricter standards impacted the cost of continuing to rely on our coal fired power plants in our 2016 IRP analysis.

Change impacting Vectren's modeling also resulted from actions of industrial operations in its service territory. In January of this year, Alcoa announced it would permanently cease production of its Warrick Operation smelter in the 1st quarter. Alcoa also communicated that the on-site rolling mill and power plant will continue to operate. Of Alcoa's generating units, Warrick 4 is jointly owned by Alcoa and Vectren. Alcoa is in the midst of operational and organizational changes. It is uncertain whether Alcoa will continue to run the jointly owned Warrick 4 electric generating unit. Vectren will continue talks with Alcoa as to the best course of action for Warrick 4. Also, one of Vectren's large customers brought on-line a large cogeneration facility that impacted Vectren's load forecast.

Other changes arose from efforts to continue to refine the IRP process. Vectren developed a more robust risk modeling approach for the 2016 IRP. Studies of potential customer-owned combined heat and power generation facilities were analyzed.

9.2 DISCUSSION OF PLANS FOR NEXT 3 YEARS

9.2.1 DSM

Vectren will seek Commission-approval for its 2018-2020 electric demand side management (DSM) plan in 2017. The 2018-2020 energy efficiency savings will be guided by the 2016 IRP process. Once approved by the Commission, the Vectren Oversight Board, including the Office of Consumers Counselor (OUCC), Citizens Action Coalition (CAC), and Vectren, will oversee the implementation of energy efficiency programs.

9.2.2 Solar Projects

Vectren will seek Commission approval to own and construct 4-6 MWs of energy company owned solar projects in its service territory, including:

- 2 MW universal solar power plant with a 1 MWh battery storage system

- a project to develop a solar power plant with the City of Evansville, details of which are expected to be finalized in the first quarter 2017, and
- other potential project discussions (on-going).

Additionally, Vectren plans to file and seek approval for 50 MW of solar. The timing of this project was advanced to enable Vectren to reap benefits of clean energy tax incentives for its customers. Timing of this solar power plant may change based on the availability of these incentives.

9.2.3 Environmental Permits for ELG/CCR

Vectren has timely NPDES permit renewals pending for Brown and Culley. As part of this permit renewal process Vectren will establish a compliance schedule for constructing new water pollution control equipment at FB Culley and list retirement dates for units that will not be upgraded. Vectren will seek Commission-approval to recover costs associated with the new pollution control equipment at FB Culley.

9.2.4 Generation Transition

In early 2017 Vectren will continue to evaluate several options as it pertains to building a new CCGT; building a CCGT at the AB Brown site (currently modeled in this IRP) or partnering with another energy company on a large CCGT build. While Vectren feels that the AB Brown site is attractive to maintain reliable, on-system generation (good water supply, access to 345kv electric transmission line, limits economic impact to the community, etc.), additional analysis is needed to ensure that that Vectren is pursuing the best option for customers.

Vectren will use the coming months to develop a generation transition case, complete with timelines and costs, which will be filed with the Commission for approval. The filing is expected to seek a Certificate of Public Convenience and Necessity (CPCN) to construct a new, fully fired combined cycle gas unit.

As Vectren works to replace much of its existing coal fleet with a new Combined Cycle Gas Turbine, Vectren will enter MISO's Generator Interconnection Queue process. During this process, MISO studies the impacts of new generation on the MISO transmission system and identifies any needed transmission facility upgrades. The process takes approximately 18 months and upon completion of satisfying any identified upgrades, Vectren will obtain a signed Generator Interconnection Agreement that will allow the new Combined Cycle Gas Turbine to connect to MISO's transmission system and participate in the MISO energy markets.

9.2.5 Ability to Finance the Preferred Portfolio

The Company has access to a $350 million revolving credit facility through its parent company Vectren Utility Holdings, Inc. ("VUHI"), internal cash flows, and transfers of cash flow from nonutility businesses. Additionally, Vectren and its subsidiary companies have strong investment grade ratings from both Moody's and Standard and Poor's, which affords access to the capital markets at attractive rates. This flexibility and ample access to funds will allow for the funds to be obtained in a manner consistent with the timing of the capital expenditures.

SECTION 10
TECHNICAL APPENDIX

10.1 CUSTOMER POWER NEEDS APPENDIX

10.1.1 Forecast Inputs

10.1.1.1 Energy Data

Historical Vectren sales and revenues data were obtained through an internal database. The internal database 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 exported out of the database and compiled in a spreadsheet on a monthly basis. The data was then organized by rate code and imported into the load forecasting software.

10.1.1.2 Economic and Demographic Data

Economic and demographic data was provided by Moody's Economy.com for the nation, the state of Indiana, and the Evansville Metropolitan Statistical Area (MSA). Moody's Economy.com, a division of Moody's Analytics, is a trusted source for economic data that is commonly utilized by utilities for forecasting electric sales. The monthly data provided to Vectren 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.

10.1.1.3 Weather Data

The daily maximum and minimum temperatures for Evansville, IN were obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. NOAA data is used to calculate monthly heating degree days (HDD) and cooling degree days (CDD). HDDs are defined as the number of degrees below the base temperature of 65 degrees Fahrenheit for a given day. CDDs are defined as the number of degrees above the base temperature of 65 degrees Fahrenheit for a given day. HDDs and CDDs are averaged on a monthly basis. Normal degree days, as obtained from NOAA,

are based on a thirty year period. 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.

10.1.1.4 Equipment Efficiencies and Market Shares Data

Itron Inc. provides regional Energy Information Administration (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. Note that in 2013 an appliance survey of Vectren's residential customers was conducted to compare its territory market share data with the regional EIA data. In order to increase the accuracy of the residential average use model, regional equipment market shares were altered to reflect those of Vectren's actual territory.

10.1.2 Appliance Saturation Survey and Continuous Improvement

Vectren surveys residential customers as needed. A residential appliance saturation survey was conducted in the summer of 2013. The survey was completed by a representative sample of customers. Results from this survey were used to reflect market shares of actual residential customers. The residential average use model statistics were improved by calibrating East South Central Census regional statistics with the appliance saturation of Vectren's customers. Note that Vectren's service area is technically in the southern most point of the East North Central Census region, bordering the Ease South Central region. Model results were improved by calibrating to the East South Central region.

At this time, Vectren does not conduct routine appliance saturation studies of GS and large customers. These customers are surveyed when needed for special programs. However, Vectren's large and GS marketing representatives maintain close contact with its largest customers. This allows Vectren to stay abreast of pending changes in demand and consumption of this customer group.

Vectren continually works to improve the load forecasting process in a variety of ways. First, Vectren 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. Vectren 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. Vectren forecasters periodically attend continuing education workshops and webinars on various forecasting topics to help improve skills and learn new techniques. Additionally, Vectren discusses forecasts with the State Utility Forecasting Group and other Indiana utilities to better understand their forecasts. Vectren compares and contrasts Vectren model assumptions and results to these groups to gain a better understanding of how they interpret and use model inputs.

10.1.3 Overview of Past Forecasts

The following tables outline the performance of Vectren's energy and demand forecasts over the last several IRPs by comparing Weather Normalized (WN) sales and demand figurers to IRP forecasts from 2006-2014.

Weather-normalization is performed each month by importing customer count, meter read schedule, billing month sales, and daily temperature into Vectren's Electric AUPC Estimation system. Underlying the Electric AUPC Estimation System is a set of MetrixND (Itron's statistical modeling software) 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, and daily system delivery data. On execution, the Use per Customer (UPC) project files read actual weather data from the Access weather database and generate daily use per customer estimates for the revenue classes. The results are exported back to the AUPC system database where the predicted daily use estimates are used to allocate billed monthly sales to the calendar-month period. The models are also executed using

normal daily temperatures. Results are written back to the AUPC system database. Weather-normalized sales are then exported from the Electric AUPC Estimation system.

The following tables show the WN[49] and forecasted values for:

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

Figure 10.1 – Total Peak Demand Requirements (MW) , Including Losses and Street Lighting

Year	2005 Total Demand Forecast (MW)	2007 Total Demand Forecast (MW)	2009 Total Demand Forecast (MW)	2011 Total Demand Forecast (MW)	2014 Total Demand Forecast (MW)	WN 2016 Total Demand (MW)[50]	2005 % Diff.	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.
2006	1,326					1,325	-0.1%				
2007	1,268					1,341	5.4%				
2008	1,237	1,184				1,166	-6.1%	-1.5%			
2009	1,257	1,216				1,066	-17.9%	-14.1%			
2010	1,275	1,237	1,153			1,154	-10.5%	-7.2%	0.1%		
2011	1,294	1,252	1,179			1,132	-14.3%	-10.6%	-4.2%		
2012	1,314	1,258	1,118	1,156		1,158	-13.5%	-8.6%	3.5%	0.2%	
2013	1,333	1,265	1,115	1,156		1,144	-16.5%	-10.5%	2.6%	-1.0%	
2014	1,350	1,272	1,107	1,165		1,133	-19.2%	-12.3%	2.3%	-2.8%	
2015	1,366	1,281	1,100	1,164	1,155	1,134	-20.5%	-13.0%	3.0%	-2.6%	-1.8%
Mean Absolute Error							12.4%	9.7%	2.6%	1.7%	1.8%

[49] 2009-2014 forecastd incorporates DSM into the class level forecasts and does not include wholesale energy. Note that large sales are not significantly influenced by weather and are therefore not weather normalized. The 2005-2007 Forecasts were before the Great Recession and do not include a significant amount of DSM.
[50] 2006-2009 peak not weather normalized

Figure 10.2 – Total Energy Requirements (GWh), Including Losses and Street Lighting

Year	2005 Total Energy IRP Forecast (GWh)	2007 Total Energy IRP Forecast (GWh)	2009 Total Energy IRP Forecast (GWh)	2011 Total Energy IRP Forecast (GWh)	2014 Total Energy IRP Forecast (GWh)	WN Total Energy Results (GWh)[51]	2005 % Diff.	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.
2006	5,875					5,772	-1.8%				
2007	6,393					5,763	-10.9%				
2008	6,531	5,846				5,568	-17.3%	-5.0%			
2009	6,640	6,090				5,387	-23.3%	-13.0%			
2010	6,743	6,230	5,306			5,739	-17.5%	-8.6%	7.5%		
2011	6,846	6,329	5,460			5,857	-16.9%	-8.1%	6.8%		
2012	6,955	6,369	5,456	5,837		5,691	-22.2%	-11.9%	4.1%	-2.6%	
2013	7,060	6,422	5,434	5,807		5,768	-22.4%	-11.3%	5.8%	-0.7%	
2014	7,159	6,476	5,403	5,803		5,867	-22.0%	-10.4%	7.9%	1.1%	
2015	7,252	6,527	5,365	5,772	5,914	5,794	-25.2%	-12.6%	7.4%	0.4%	-2.1%
Mean Absolute Error							17.9%	10.1%	6.6%	1.2%	2.1%

Figure 10.3 – Residential Energy (GWh)

Year	2005 Res. IRP Forecast (GWh)	2007 Res. IRP Forecast (GWh)	2009 Res. IRP Forecast (GWh)	2011 Res. IRP Forecast (GWh)	2014 Res. IRP Forecast (GWh)	WN Res. Results (GWh)	2005 % Diff.	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.
2006	1,584					1,554	-1.9%				
2007	1,609					1,550	-3.8%				
2008	1,633	1,581				1,520	-7.5%	-4.0%			
2009	1,660	1,595				1,520	-9.2%	-4.9%			
2010	1,687	1,620	1,467			1,483	-13.8%	-9.2%	1.1%		
2011	1,716	1,645	1,440			1,483	-15.7%	-10.9%	2.9%		
2012	1,745	1,663	1,421	1,462		1,411	-23.7%	-17.9%	-0.7%	-3.6%	
2013	1,774	1,683	1,391	1,419		1,429	-24.1%	-17.7%	2.7%	0.7%	
2014	1,801	1,703	1,365	1,399		1,439	-25.2%	-18.3%	5.1%	2.8%	
2015	1,830	1,722	1,332	1,371	1,404	1,444	-26.7%	-19.2%	7.8%	5.0%	2.8%
Mean Absolute Error							15.1%	12.8%	3.4%	3.0%	2.8%

[51] Assumes 5.2% losses

Figure 10.4 – Commercial (GS) Energy (GWh)

Year	2005 Comm. (GS) IRP Forecast (GWh)	2007 Comm. (GS) IRP Forecast (GWh)	2009 Comm. (GS) IRP Forecast (GWh)	2011 Comm. (GS) IRP Forecast (GWh)	2014 Comm. (GS) IRP Forecast (GWh)	WN Comm. (GS) Results (GWh)	2005 % Diff.	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.
2006	1,566					1,342	-16.7%				
2007	1,594					1,371	-16.3%				
2008	1,625	1,380				1,346	-20.7%	-2.5%			
2009	1,660	1,384				1,324	-25.4%	-4.6%			
2010	1,694	1,404	1,275			1,321	-28.3%	-6.3%	3.4%		
2011	1,727	1,426	1,284			1,318	-31.0%	-8.2%	2.6%		
2012	1,764	1,438	1,296	1,375		1,266	-39.3%	-13.6%	-2.3%	-8.6%	
2013	1,800	1,455	1,304	1,383		1,298	-38.7%	-12.1%	-0.4%	-6.6%	
2014	1,834	1,472	1,307	1,399		1,312	-39.8%	-12.2%	0.4%	-6.6%	
2015	1,863	1,490	1,306	1,402	1,304	1,321	-41.1%	-12.8%	1.1%	-6.2%	1.3%
Mean Absolute Error							29.7%	9.0%	1.7%	7.0%	1.3%

Figure 10.5 – Industrial (Large) Energy (GWh)

Year	2005 Ind. (Large) IRP Forecast (GWh)	2007 Ind. (Large) IRP Forecast (GWh)	2009 Ind. (Large) IRP Forecast (GWh)	2011 Ind. (Large) IRP Forecast (GWh)	2014 Ind. (Large) IRP Forecast (GWh)	WN Ind. (Large) Results (GWh)	2005 % Diff.	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.
2006	2,379					2,570	7.4%				
2007	2,422					2,538	4.6%				
2008	2,461	2,591				2,409	-2.2%	-7.5%			
2009	2,498	2,820				2,259	-10.6%	-24.9%			
2010	2,530	2,921	2,281			2,630	3.8%	-11.0%	13.3%		
2011	2,561	2,980	2,445			2,745	6.7%	-8.6%	10.9%		
2012	2,594	2,999	2,449	2,687		2,711	4.3%	-10.6%	9.7%	0.9%	
2013	2,624	3,014	2,449	2,693		2,735	4.1%	-10.2%	10.4%	1.5%	
2014	2,650	3,028	2,446	2,693		2,805	5.5%	-8.0%	12.8%	4.0%	
2015	2,674	3,040	2,445	2,688	2,916	2,722	1.7%	-11.7%	10.1%	1.2%	-7.1%
Mean Absolute Error							5.1%	11.6%	11.2%	1.9%	7.1%

Figure 10.6 – Historic Energy and Demand

	Res.	Comm. (GS) Sales	Ind. (Large)	Other	Total Energy[52]	Total Demand[53]
2006	1,469	1,321	2,570	20	5,660	1,165
2007	1,631	1,412	2,538	19	5,892	1,182
2008	1,514	1,337	2,409	18	5,552	1,097
2009	1,452	1,309	2,259	19	5,300	1,076
2010	1,604	1,361	2,630	21	5,908	1,204
2011	1,499	1,329	2,745	21	5,884	1,152
2012	1,434	1,297	2,711	21	5,748	1,192
2013	1,415	1,287	2,735	21	5,742	1,091
2014	1,455	1,307	2,805	21	5,879	1,084
2015	1,408	1,307	2,722	21	5,737	1,089

10.2 ENVIRONMENTAL APPENDIX

10.2.1 Air Emissions

It was assumed that current or future generation resources would not exceed Vectren's allocated SO_2 and NOx emission allowances. Vectren'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.

Figure 10.7 – Air Pollution Control Devices Installed

	FB Culley 2	FB Culley 3	Warrick 4	AB Brown 1	AB Brown 2
Vintage	1966	1973	1970	1979	1986
MW (net)	90	270	150	245	245
NO_X	Low NO_X Burner	SCR	SCR	SCR	SCR
SO_2	FGD	FGD	FGD	FGD	FGD
PM	ESP	FF	ESP	FF	ESP
MATs	Shared w/ U3	Injection	Injection	Injection	Injection
SO_3		Injection	Injection	Injection	injection

[52] Assumes 5.2% Losses
[53] Does not include municipal demand

Figure 10.8 – CSAPR SO_2 Allowances Current through 11/15/2014 & Seasonal NO_X Allowances Current through 11/24/2014

SO_2				
	AB Brown	FB Culley	SIGECO W4	Total
2016	7,894	4,411	2,892	15,197
2017	4,423	3,890	1,620	9,933
2018	4,423	3,890	1,620	9,933
2019	4,423	3,890	1,620	9,933

NOx					
	AB Brown	BAGS	FB Culley	SIGECO W4	Total
2016	1,214	21	1,060	445	2,740
2017	1,195	21	1,044	437	2,697
2018	1,195	21	1,044		2,698
2019	1,195	21	1,044	437	2,697

Figure 10.9 – CSAPR Seasonal NOx Allowances Current through 9/16/2016

	AB Brown	BAGS	FB Culley	SIGECO W4	Total
2016	1,214	21	1,060	445	2,740
2017	658	6	465	227	1,356
2018	658	6	465	227	1,356
2019	658	6	465	227	1,356

10.2.2 Solid Waste Disposal

Scrubber by-products from AB Brown are sent to an on-site landfill permitted by Indiana Department of Environmental Management (IDEM). During the fall of 2009, Vectren finalized construction of a dry fly ash silo and barge loading facility that would allow for the beneficial reuse of Vectren-generated fly ash. Since February 2010, the majority of AB Brown fly ash is diverted to the new dry ash handling system and sent for beneficial reuse to a cement processing plant in St. Genevieve, Missouri via a river barge loader and conveyor system. 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 Vectren's coal combustion materials are now being diverted from the existing ash pond structures and surface coal mine backfill operations and transported offsite for recycling into a cement application.

Fly ash from the FB Culley facility is similarly transported off-site for beneficial reuse in cement. In May 2009, Culley began trucking fly ash to the St. Genevieve cement plant. Upon completion of the barge loading facility at the AB Brown facility in late 2009, FB Culley's fly ash is now transported to the AB Brown loading facility and shipped to the cement plant via river barge. The FB Culley facility sends its bottom ash to the East ash pond via wet sluicing. The pond is approximately 10 acres in size. The West pond (27 acres) no longer receives bottom ash, but continues to accept coal pile run-off and general storm water from the west side of the plant, including the plant entrance road. Scrubber by-product generated by the FB Culley facility is also used for beneficial reuse and shipped by river barge from FB Culley to a wallboard manufacturer. In summary, the majority of Vectren's coal combustion material is no longer handled on site, but is being recycled and shipped off-site for beneficial reuse.

10.2.3 Hazardous Waste Disposal

Vectren's AB Brown and FB 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 Conditionally Exempt Small Quantity Generators.

10.2.4 Water Consumption and Discharge

AB Brown and FB Culley currently discharge process and cooling water to the Ohio River under National Pollutant Discharge Elimination System (NPDES) water discharge permits issued by the Indiana Department of Environmental Management (IDEM). AB Brown utilizes cooling towers while FB 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.

10.3 DSM APPENDIX

10.3.1 Gross Savings 2016-2017 Plan

Figure 10.10 – 2016-2017 Plan Gross kWh Energy Savings

	2016*		2017**	
Sector	Gross kWh Energy Savings	kW Demand Savings	Gross kWh Energy Savings	kW Demand Savings
Residential	23,528,418	6,400	20,362,245	4,439
Commercial & Industrial	18,796,505	2,800	17,428,270	2,669
Total	42,324,923	9,200	37,790,515	7,108

*2016 Operating Plan used for 2016

**2016-2017 Filed Plan used for 2017

10.3.2 DSM Programs

Vectren has offered tariff based DSM resource options to customers for a number of years. Consistent with a settlement approved in 2007 in Cause No. 43111, the Demand Side Management Adjustment (“DSMA”) was created to specifically recover all of Vectren's Commission approved DSM costs, including (at that time) a DLC Component. The Commission, in its order in Cause No. 43427, authorized Vectren 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.

10.3.3 Impacts

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

Figure 10.11 – 2016 Electric DSM Operating Plan Program Savings

Program	Residential/ Commercial	Particicpants	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross KW/ Participant	Net KW
Residential Lighting	Residential	314,618	67%	7,923,516	25	5,308,756	1,167	0.004	782
Home Energy Assessments	Residential	1,500	98%	2,048,260	1,366	2,007,295	262	0.17	257
Income Qualified Weatherization	Residential	485	100%	1,103,043	2,274	1,103,043	240	0.49	240
Appliance Recycling	Residential	950	54%	-	-	-	152	0.19	82
Energy Efficient Schools	Residential	2,400	100%	739,963	308	739,963	115	0.05	115
Residential Efficient Products	Residential	4,643	52%	1,997,855	430	1,038,885	918	0.20	477
Residential New Construction	Residential	103	50%	260,756	2,532	130,378	168	1.63	84
Residential Behavioral Savings	Residential	49,751	100%	8,200,000	165	8,200,000	1,400	0.03	1,400
Multi-Family CFL's	Residential	985	100%	326,240		326,240	29	0.03	29
Conservation Voltage Reduction	Residential		100%	-		-	-		-
Nest Demand Response Pilot	Residential	1,000	80%	429,000	429	343,200	900	0.90	720
Honeywell Demand Response Pilot	Residential	1,000	80%	429,000	429	343,200	900	0.90	720
Nest On-Line	Residential	165	100%	70,785	429	70,785	149	0.90	149
Small Business Direct Install	Commercial	26,037	95%	6,619,675	254	6,288,691	878	0.03	834
Commercial & Industrial Prescriptive	Commercial	12,540	87%	6,911,630	551	6,013,119	1,303	0.10	1,134
Commercial & Industrial New Construction	Commercial	15	100%	519,000	34,600	519,000	94	6.27	94
Commercial & Industrial Custom	Commercial	25	100%	4,296,200	171,848	4,296,200	525	21.01	525
Building Tune-Up	Commercial	9	100%	450,000	50,000	450,000	-	-	-
Conservation Voltage Reduction	Commercial		0%	-					
Total		416,226	88%	42,324,923	102	37,178,754	9,200	0.02	7,642

Figure 10.12 – 2017 Electric DSM Filed Planned Savings

Program	Residential/ Commercial	Participants	NTG	Gross kWh	Gross kWh per Participant	Net kWh	Gross KW	Gross kWh per Participant	Net KW
Residential Lighting	Residential	233,899	67%	6,831,909	29	4,577,379	865	0.004	580
Home Energy Assessments	Residential	2,125	98%	1,935,719	911	1,897,004	290	0.14	284
Income Qualified Weatherization	Residential	564	100%	1,282,577	2,274	1,282,577	254	0.45	254
Appliance Recycling	Residential	952	54%	1,020,544	1,072	551,094	152	0.16	82
Energy Efficient Schools	Residential	2,400	100%	675,508	281	675,508	106	0.04	106
Residential Efficient Products	Residential	2,216	52%	1,075,888	486	559,462	623	0.28	324
Residential New Construction	Residential	103	50%	146,775	1,425	73,388	68	0.66	34
Residential Behavioral Savings	Residential	43,500	100%	5,576,656	128	5,576,656	1,553	0.04	1,553
Multi-Family CFL's	Residential	5,500	100%	335,000	61	335,000	20	0.00	20
Conservation Voltage Reduction	Residential	5,324	100%	1,481,669	278	1,481,669	508	0.10	508
Nest Demand Response Pilot	Residential		80%	-		-	-		-
Honeywell Demand Response Pilot	Residential		80%	-		-	-		-
Nest On-Line	Residential		100%	-		-	-		-
Small Business Direct Install	Commercial	17,235	95%	6,000,810	348	5,700,770	906	0.05	861
Commercial & Industrial Prescriptive	Commercial	12,222	87%	6,910,197	565	6,011,871	1,088	0.09	947
Commercial & Industrial New Construction	Commercial	15	100%	534,135	35,609	534,135	94	6.27	94
Commercial & Industrial Custom	Commercial	25	100%	2,906,300	116,252	2,906,300	385	15.40	385
Multi Family Retrofit Pilot Program	Commercial	100	100%	201,785	2,018	201,785	33	0.330	33
Conservation Voltage Reduction	Commercial	558	100%	875,044	1,568	875,044	163	0	163
Total		326,738	87%	37,790,515	116	33,239,641	7,075	0.02	6,227

10.3.4 Avoided Costs

The avoided power capacity costs are reflective of the estimated replacement capital and fixed operations and maintenance cost. For this avoided cost analysis, a 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. Avoided capacity costs should only be considered avoidable when there is a planning reserve margin deficit that would otherwise need to be met through a new capacity resource.

The marginal operating energy costs were based off the modeled Vectren system marginal energy cost from the base optimized scenario under base assumptions. This included emission cost for CO_2 starting in 2024, 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.

Figure 10.13 – Avoided Costs[54]

	Natural Gas Forecast $/MMBTu	CO_2 Forecast $/Short Ton	Economic Carrying Charge[55] $/kW	Transmission/ Distribution Avoided Cost $/kW (10% of Carrying Charge)	Total Capacity Avoided Cost $/kW	System Marginal Cost $/MWh	System Marginal Cost $/kWh
2017	$2.94		$91.82	$9.18	$101.00	$28.62	$0.02862
2018	$3.13		$92.55	$9.25	$101.80	$30.93	$0.03093
2019	$3.65		$93.41	$9.34	$102.76	$33.95	$0.03395
2020	$3.90		$94.99	$9.50	$104.49	$35.90	$0.03590
2021	$4.05		$96.77	$9.68	$106.45	$36.09	$0.03609
2022	$4.23		$98.30	$9.83	$108.13	$36.61	$0.03661
2023	$4.40		$100.00	$10.00	$110.00	$36.73	$0.03673
2024	$4.63	$2.29	$100.85	$10.09	$110.94	$40.78	$0.04078
2025	$4.77	$3.70	$102.19	$10.22	$112.41	$42.19	$0.04219
2026	$4.97	$5.87	$103.89	$10.39	$114.27	$44.98	$0.04498
2027	$5.22	$9.83	$106.32	$10.63	$116.95	$49.09	$0.04909
2028	$5.45	$12.71	$107.73	$10.77	$118.51	$52.58	$0.05258
2029	$5.68	$17.54	$109.23	$10.92	$120.15	$57.65	$0.05765
2030	$5.90	$19.50	$110.56	$11.06	$121.62	$60.23	$0.06023
2031	$6.07	$21.11	$112.38	$11.24	$123.62	$62.27	$0.06227
2032	$6.32	$23.60	$114.21	$11.42	$125.64	$65.42	$0.06542
2033	$6.46	$23.63	$115.76	$11.58	$127.33	$66.61	$0.06661
2034	$6.67	$24.58	$117.42	$11.74	$129.17	$68.66	$0.06866
2035	$6.89	$26.34	$119.98	$12.00	$131.98	$71.30	$0.07130
2036	$7.13	$28.14	$122.37	$12.24	$134.60	$73.90	$0.07390

10.4 RESOURCE SCREENING APPENDIX

10.4.1 Busbar Analysis

[54] Reflective of the 2016 IRP Base Scenario Optimized Case B as of September 20, 2016
[55] Economic Carrying Charge is not an avoidable cost if there is no capacity requirement

Figure 10.14 – New Construction Alternatives

Resource[56]	Net Operating Capacity (MW)	Fuel Type	Accepted or Rejected as Resource Alternative	Reason to Accept or Reject
LM6000 Simple Cycle Gas Turbine	43.4	Natural Gas	Rejected	Not cost effective compared to alternatives
LMS100 Simple Cycle Gas Turbine	99.5	Natural Gas	Rejected	Not cost effective compared to alternatives
E-Class Simple Cycle Gas Turbine	90.1	Natural Gas	Rejected	Not cost effective compared to alternatives
F-Class Simple Cycle Gas Turbine	**220**	**Natural Gas**	**Accepted**	**Cost effective**
1x1 7EA CCGT	170	Natural Gas	Rejected	Not cost effective compared to alternatives
1x1 7FA.05 CCGT	**442**	**Natural Gas**	**Accepted**	**Cost effective for size**
2x1 7FA.04	**745**	**Natural Gas**	**Accepted (select scenarios)**	**Not cost effective compared to alternatives**
2x1 7FA.05	**889**	**Natural Gas**	**Accepted**	**Cost effective for size**
3x1 7FA.05	1337	Natural Gas	Rejected	Exceeds capacity needs
1 MW Microturbine	1.0	CHP-Natural Gas	Rejected	Not cost effective compared to alternatives
3 MW Combustion Turbine	3.2	CHP-Natural Gas	Rejected	Not cost effective compared to alternatives
5 MW Combustion Turbine	5.1	CHP-Natural Gas	Rejected	Not cost effective compared to alternatives
10 MW Combustion Turbine	10.3	CHP-Natural Gas	Rejected	Not cost effective compared to alternatives
14 MW Combustion Turbine	**13.6**	**CHP-Natural Gas**	**Accepted**	**Cost effective CHP**
Supercritical Pulverized Coal 500 MW with Carbon Capture	430	Coal	Rejected	Not cost effective compared to alternatives
Supercritical Pulverized Coal 750 MW with Carbon Capture	640	Coal	Rejected	Not cost effective compared to alternatives
2x1 Integrated Gasification Combined Cycle with Carbon Capture	480	Coal	Rejected	Not cost effective compared to alternatives
Wood Stoker Fired	50	Wood Biomass	Rejected	Not cost effective

[56] Combined cycle gas turbines are shown as duct fired configuration for this table.

Resource[56]	Net Operating Capacity (MW)	Fuel Type	Accepted or Rejected as Resource Alternative	Reason to Accept or Reject
				compared to alternatives
Landfill Gas IC Engine	5	Landfill Gas	Rejected	Not cost effective compared to alternatives
Lithium Ion (10 MW/40 MWh)	**10**	**Battery Storage**	**Accepted (select scenarios)**	**Cost effective battery**
Lithium Ion (1 MW/4 MWh)	1	Battery Storage	Rejected	Not cost effective compared to alternatives
Commercial Battery (0.1 MW/0.25 MWh)	0.1	Battery Storage	Rejected	Not cost effective compared to alternatives
Residential Battery (0.002 MW/ 0.007 MWh)	.002	Battery Storage	Rejected	Not cost effective compared to alternatives
Compressed Air Energy Storage	100	Storage	Rejected	Not feasible in Vectren's service territory
Wind (North Dakota 50 MW)	50	Renewables	Rejected	Transmission costs are cost prohibitive
Wind (North Dakota 200 MW)	200	Renewables	Rejected	Transmission costs are cost prohibitive
Wind (Indiana 50 MW)	**50**	**Renewables**	**Accepted**	**Low cost renewable energy for size**
Wind (Indiana 200 MW)	**200**	**Renewables**	**Accepted**	**Low cost renewable energy for size**
Solar Photovoltaic (3 MW)	3	Renewables	Rejected	Not cost effective compared to alternatives
Solar Photovoltaic (6 MW)	6	Renewables	Rejected	Not cost effective compared to alternatives
Solar Photovoltaic (9 MW)	**9**	**Renewables**	**Accepted**	**Low cost renewable capacity for size**
Solar Photovoltaic (50 MW)	**50**	**Renewables**	**Accepted**	**Low cost renewable capacity for size**
Solar Photovoltaic (100 MW)	100	Renewables	Rejected	Acreage required may be difficult to find in Vectren's service territory
Hydroelectric	50	Hydroelectric	Rejected	Not cost effective compared to alternatives

10.5 RISK APPENDIX

As described further below, uncertainty is addressed in two different ways: first, by subjecting technologies to a variety of market outcomes in the screening analysis to ensure that Vectren has selected technologies in its portfolios that will perform well in a variety of future conditions, and second, in a more comprehensive risk analysis where the range of future conditions on the selected portfolios is more fully captured.

Key to this more comprehensive risk analysis is a stochastic risk assessment that bounds the uncertainty, captures the variability, and identifies the risk exposure inherent in long-term power generation planning. Variability results from supply and demand disruptions, market conditions, technology improvements, economic cycles, and weather, all of which are captured in Vectren's Risk Integrated IRP approach. To capture this variability, a Monte Carlo simulation is used to evaluate the range of possible futures as well as their likelihoods. The stochastic model estimates probability distributions of potential outcomes by allowing for simultaneous random-walking yet inter-correlated variation in many inputs over time, including gas prices, coal prices, carbon prices, capital costs, and load growth. These boundary conditions and probability bands then help to inform decision making on each portfolio's overall benefit-risk profile.

10.5.1 Stochastics

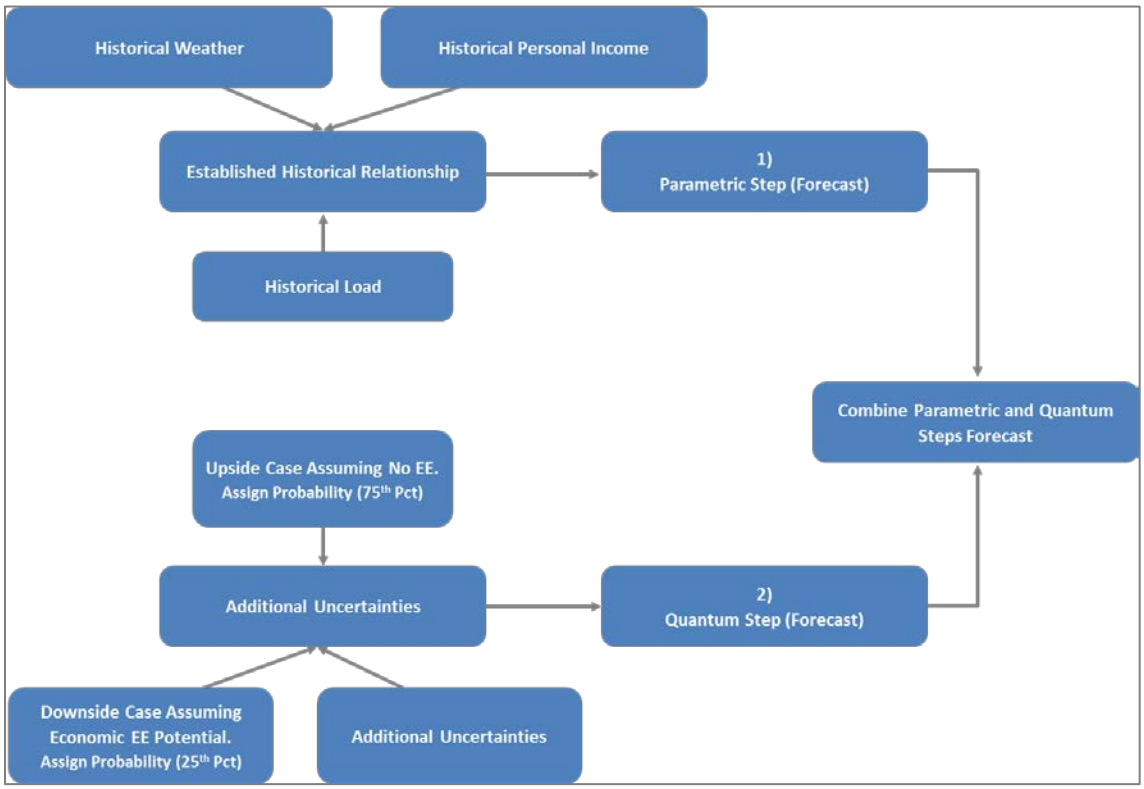
10.5.1.1 Load Stochastics

To account for variations in electricity demand stemming from economic growth, weather, and energy efficiency and demand side management measures, Pace Global developed stochastics around the load growth expectations for the Vectren control area and the neighboring ISO zones. While values in the 95th percentile are driven by strong economic growth, values in the 5th percentile are driven by economic stagnation as well as energy efficiency and demand-side management implementation.

Pace Global' s long-term load forecasting process is a two-step process that captures both the impact of historical load drivers such as economic growth and variability of weather (parametric step) and the possible disruptive impacts of energy efficiency penetration (quantum step) in constructing the average and peak demand outlook.

Pace Global benchmarked the projections against MISO-sponsored load forecasting studies that are conducted by independent consultants and institutions and then released into the public domain. The process to benchmark the load to MISO's forecasts was undertaken during the quantum step, which is described below.

Figure 10.15 – Pace Global's Load Forecast Process



The parametric step separately employs a unique econometric model for each MISO Local Resource Zone (LRZ) based on the historical relationships between average and peak load, and key driver variables, including temperature data (HDD, CDD, and humidity) and an economic factor variable (personal income for the geographical area).

Pace Global used the historical personal income drift rates and volatility and a sampling from 17 years of historical data for each region to assess the distribution of overall load growth conditions for each year of the forecast. The base average and demand forecast were based on the average of the peak and average demand forecasts.

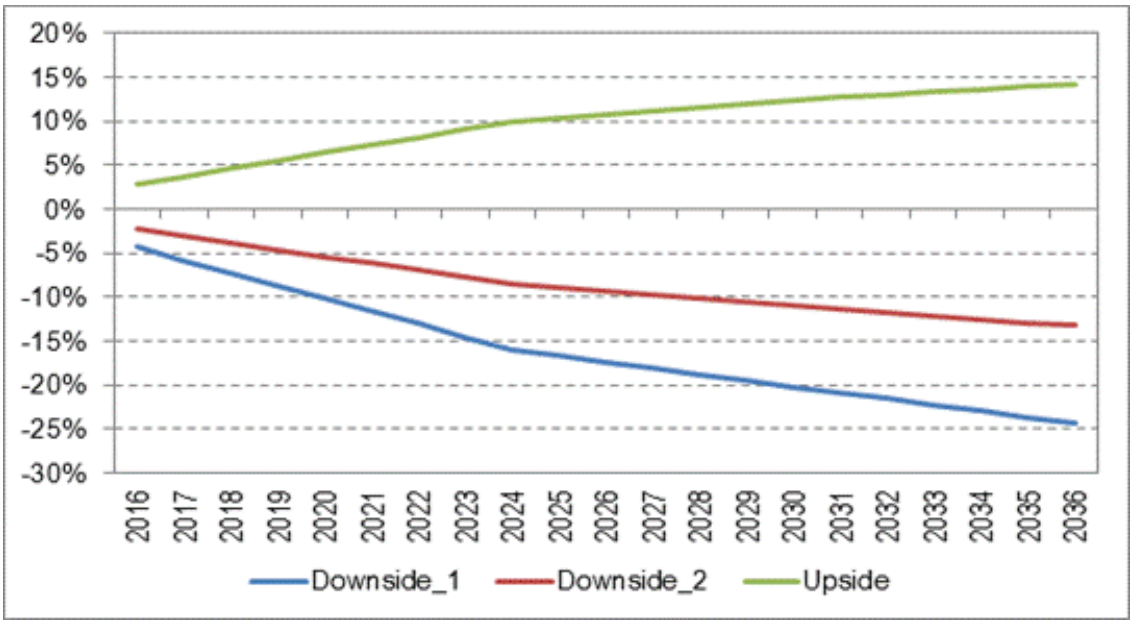
The quantum step assessed the possible disruptive impacts of energy efficiency on the average and peak loads in MISO. Pace constructed three energy efficiency scenarios using publically available FERC and NERC reports data:

1. Upside scenario: No significant savings from efficiency programs
2. Downside scenario 2: Energy efficiency penetration dictated by current economic value
3. Downside scenario 1: Additional energy efficiency penetration driven by federal and state programs to achieve energy efficiency technical potential

In addition, Pace Global used the most recent historical average and peak load for each MISO LRZ and the forecasted compounded annual growth rate (CAGR) of peak and average demand from MISO-sponsored 10 year independent load forecasts to benchmark and formulate a reference.

With this information, Pace Global constructed synthetic distributions for energy efficiency by assigning the upside scenario as the 75th percentile case, the base case scenario as the 50th percentile case, the economic energy efficiency potential as the low 25th percentile, and the technical energy efficiency potential as the 5th percentile. The following graph shows an illustration of the impact of three scenarios on the average demand growth rate. The average impact derived from the synthetic distribution was applied to base demand forecast obtained in the parametric step.

Figure 10.16 – Illustrative Impact of Three Scenarios on Energy Efficiency

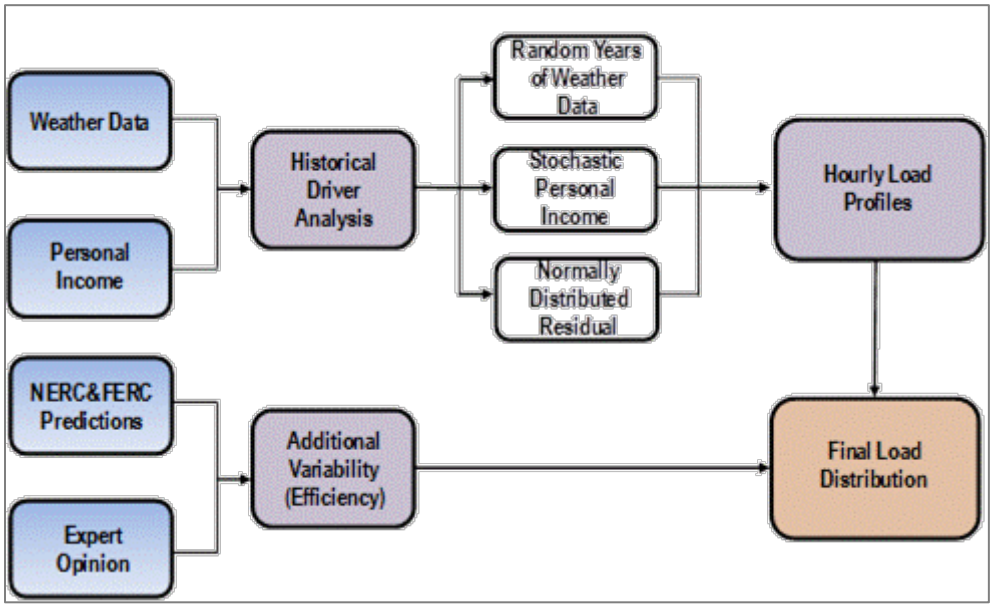


Pace Global benchmarked its outlook against the latest MISO-sponsored load forecasting study, which shows the CAGR for the next 10 year study period. The study report has a CAGR value for each of the nine LRZs. Pace Global applied the CAGR value to the actual 2015 historical load, which is the starting value, and determined a projection of the load forecast. This load forecast was considered as the base case (50th percentile) reference. The previous graph shows the high and two low percentiles as percentage increase/reductions to the reference load. For example, the 5th percentile case has a value of -16% by 2025. The base case reference load for 2025 was reduced by 16%, which corresponds to the technical potential for EE penetration. The same steps were repeated for the 25th percentile and 75th percentile cases for each year, which created a distribution of projections depicting the various "market events" that can happen in the future. For the deterministic case, the average impact from this synthetic distribution was imposed on the load forecast from the parametric step, to obtain the final load forecasts.

To address demand uncertainty in modeling and capture the risk associated with demand growth, Pace Global produced a distribution of monthly average and peak

loads using the methodology described below and summarized in the following flow chart.

Figure 10.17 – Flow Chart to Address Load Uncertainty



With respect to the historical driver analysis, Pace Global finds that historical monthly weather data and personal income explain fairly well the changes in monthly average and peak load. This relationship forms the basis for Pace Global's load uncertainty analysis. The basic premise of the model is that load can be expressed as a function of HDDs, CDDs, humidity, and personal income.

$$Load_t=\alpha+ \beta_1*HDD_t+ \beta_2*CDD_t+ \beta_3*HUM_t+ \beta_4*PI_t+ \xi_t$$

Where:

- HDD (Heating Degree Days): 65 - Average daily temperature in degrees Fahrenheit or zero (HDD is never negative)
- CDD (Cooling Degree Days): Average daily temperature -65 in degrees Fahrenheit or zero. (CDD is never negative)
- HUM (Humidity): Average daily percent humidity
- PI: Personal Income

- ξ: A normally distributed variable with mean 0 and constant variance
- α: A constant derived from the regression analysis
- β_n: Coefficients derived from the regression analysis

A stepwise regression then calibrated this model to historic data.

The load stochastics propagation was conducted in a two-step process.

Step 1: Weather and Economic Variability

To produce load stochastics, Pace Global propagated three independent random paths: weather data, personal income, and a residual. Weather data includes HDDs, CDDs, and humidity. To produce reasonable weather data projections, Pace Global sampled actual yearly paths from history. On average, Pace uses 17 years of historical data to perform the weather projections for the forward study period. Personal income is assumed to follow Geometric Brownian Motion. This means that there exists a normal distribution with constant mean and variance that describes how the return on personal income will behave at any time. Historical personal income data produces a best estimate for the relevant monthly mean and variance of this process going forward. Finally, to account for unexplained variation in the observed data, Pace Global added a normally distributed residual with mean zero and standard deviation equal to the root mean squared error of the previously mentioned stepwise regression.

Step 2: Additional Variability

Pace Global believes that future power demand may differ substantially from past power demand. To accommodate for this possibility, an additional “efficiency distribution” was added to the empirically derived distribution. The distribution is log-normally distributed. The 5th percentile of this distribution is taken primarily from NERC and FERC projections (or other relevant data sources) for statewide potential for load reduction from efficiency or other DSM measures. For example, these measures may include smart meter infrastructure, appliance energy efficiency standards, or other direct load control programs. The upper tail of this distribution was weighted to match Pace

Global's analysis of historical high periods of load growth and Pace Global's expert opinion. Note that the "efficiency distribution" incorporates the potential for limited or no penetration of the expected increases in the energy efficiency of the economy embedded in the base case. Examples include increasing residential plug load or high energy consumption technology breakthroughs. Pace Global expects that changes attributable to the efficiency distribution will affect load growth on a large geographic scale. Accordingly, concurrent energy efficiency changes are highly correlated across regions. Additionally, Pace Global expects that incremental efficiency changes will persist over time. Accordingly, the propagations have a high level of serial correlation.

10.5.1.2 Gas Stochastics

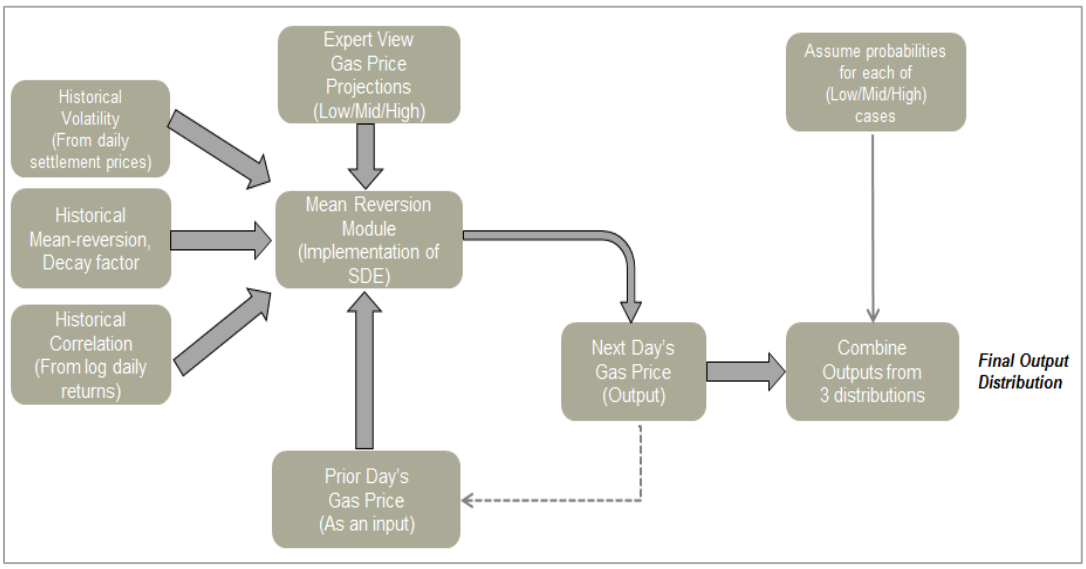
Pace Global developed natural gas stochastic distributions for Henry Hub and other basis points, including points relevant to Indiana. These stochastic distributions are based on a base case view of natural gas prices with probability bands developed based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility.

Pace Global developed stochastics around the price at the Henry Hub and other hubs based, including points relevant to Indiana, on historical volatility, current market forwards, and a long-term term fundamental view that takes into account the expected supply-demand balance. To estimate future volatility, the volatility of the last 30 months is applied to 2016-2018, the volatility from 2011-2015 is applied to 2019-2025, and the volatility from 2005-2015 is applied to 2026-2035. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95th percentile probability bands are driven by increased gas demand (most likely due to coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization down as well as little to no environmental legislation around power plant emissions.

The steps involved in the development of gas stochastics are as follows:

- As the first step, Pace developed the long-term fundamental forecast of Henry Hub and many other North American gas hub bases to the Henry Hub (using the Gas Pipeline Competition Model or GPCM). The probability distributions were developed around this fundamental forecast.
- From historical data sets, the volatility parameter was calculated using the daily settled prices. Volatilities for different historical time periods were calculated (such as past 10-years, past 5 years, recent 2.5 years etc.)
- The daily gas prices were modeled as a single-factor continuous mean-reverting process. The mean reversion parameter was also calculated from the historical daily settled prices.
- For several gas hub bases that are deemed to be correlated, the appropriate correlations were calculated from the historical data.
- The entire process to develop the gas stochastics is described in the exhibit below:

Figure 10.18 – Pace Global's Gas Stochastics Process



- The volatilities tend to vary for different time periods. In order to capture this for the forecast time period, different volatility values from different historical time

periods were considered. For example, for the first three forecast years (2016-2018), volatility calculated from the past 30 months price data is used. For years 4-10 (2019-2025), volatility calculated from the past five years (2011-2015) is used. Beyond that time period (2026-2035), the past 10-year historical volatility (2005-2015) is used.

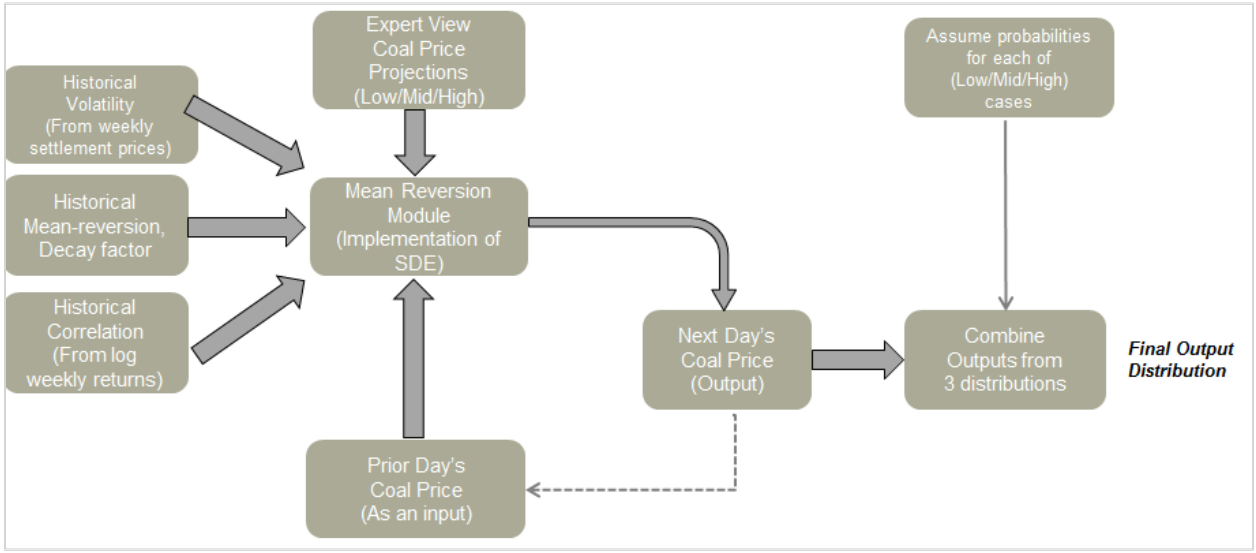
- The long-term fundamental forecast for each month in the forecast time period was treated as the mean-reverting level in this process.

10.5.1.3 Coal Stochastics

Pace Global developed coal price stochastic distributions for CAPP, NAPP, ILB and PRB basins. These stochastic distributions are based on a reference case view of coal prices with probability bands developed based on a combination of historical volatility and mean reversion parameters. It should be noted that a majority of coal contracts in the U.S. are bilateral and only about 20 percent are traded on the NYMEX. The historical data set that was used to calculate the parameters is comprised of the weekly traded data reported in NYMEX.

The methodology involved in the distribution of stochastic coal prices is exactly the same as that used for natural gas stochastics.

Figure 10.19 – Pace Global's Coal Stochastics Process



The steps involved in the development of coal basin price stochastics are as follows:

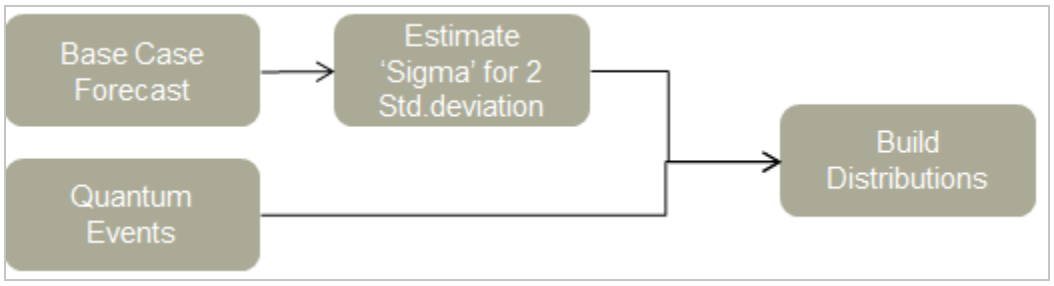
- As the first step, Pace developed the long-term fundamental forecast of each of the coal basins. The probability distributions were developed around these fundamental forecasts.
- From historical data sets, the volatility parameter was calculated using weekly prices. Volatilities for different historical time periods were calculated (such as past 10-years, past 5 years, recent 2.5 years etc.)
- The coal prices were modeled as a single-factor continuous mean-reverting process. The mean reversion parameter was also calculated from the historical prices.
- For the four coal basin prices, the appropriate correlations were calculated from the historical data.

10.5.1.4 Emissions Stochastics

Pace Global developed uncertainty distributions around carbon compliance costs, which were used in the power dispatch modeling to capture the inherent risk associated with regulatory compliance requirements.

The technique to develop carbon costs distributions, unlike the previous variables, is based on Pace Global' expert opinion based projections. There are no historical data sets to estimate the parameters for developing carbon costs distributions. Accordingly, the views of Pace Global's subject matter experts are taken into consideration. The exhibit below shows the high level methodology for developing stochastic distributions, when the historical data is not available.

Figure 10.20 – Pace Global's Emissions Stochastics Process



Given below are the steps involved in this process:

- Pace's environmental team developed a base case forecast, and an associated high and low case. In addition to the high and low cases, the probability values for the high and low cases were developed.
- These three cases are treated as 16th, 50th and 84th percentiles. Using these percentiles and statistical techniques, the standard deviation values were calculated.
- The base case is treated as the mid-case (median).
- Using the standard deviation values and a sampling from an underlying standard normal distribution (which has a mean zero and variance one), the probability bands were constructed around the reference projections. This underlying distribution captures the quantum events that can happen in the market.
- The distributions were then adjusted to incorporate probabilities such as "*the probability of a CO_2 program not taking effect*" and "*a greater chance of a nation-wide CO_2 regime starting in 2022,*" etc.

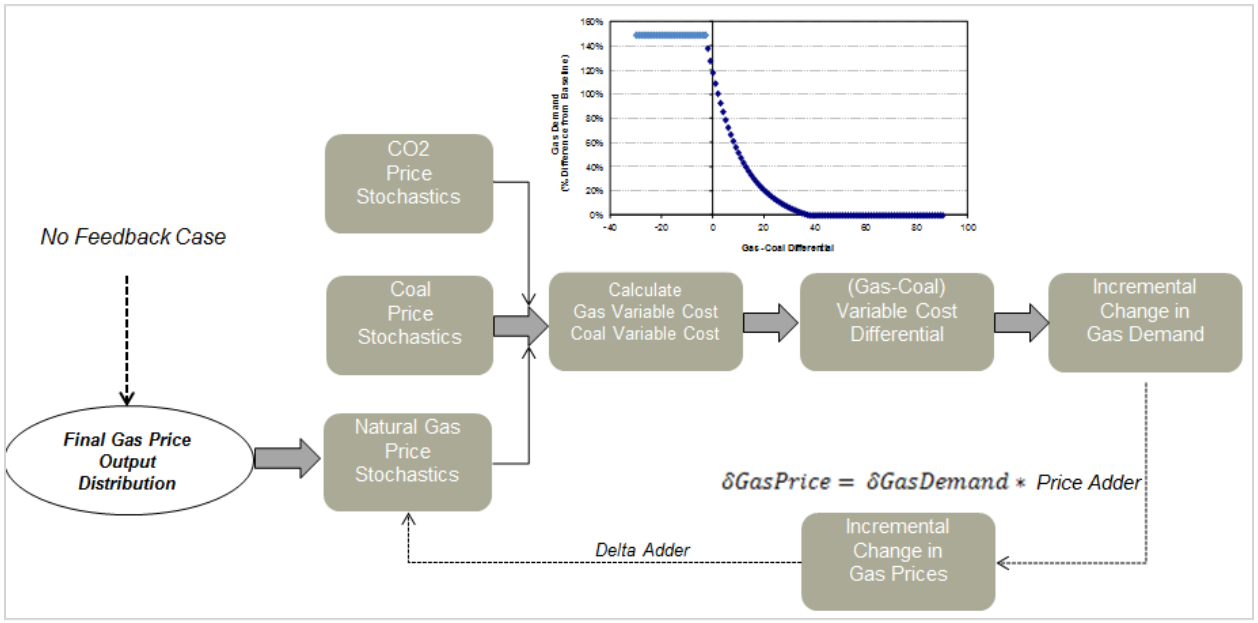
- Separate distributions were developed for national carbon costs, California carbon costs, and RGGI prices, which were then applied to the respective states.

10.5.1.5 Gas-Coal-CO_2 Prices Feedback (Cross-Commodity Correlations) Stochastics

Pace Global has implemented a distinct process to capture the cross-commodity correlations into the stochastic processes. This is a separate process which is implemented after modeling the gas, coal, and CO2 processes discussed above.

The exhibit below describes the coal and CO_2 feedback loops that affect gas prices. At a high level, the feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators.

Figure 10.21 – Pace Global's Cross-Commodity Correlation Stochastics Process



- Pace performed fundamental analysis to define the relationship between gas-coal dispatch cost and demand; incremental gas demand curve as a function of the gas-coal differential was calibrated.

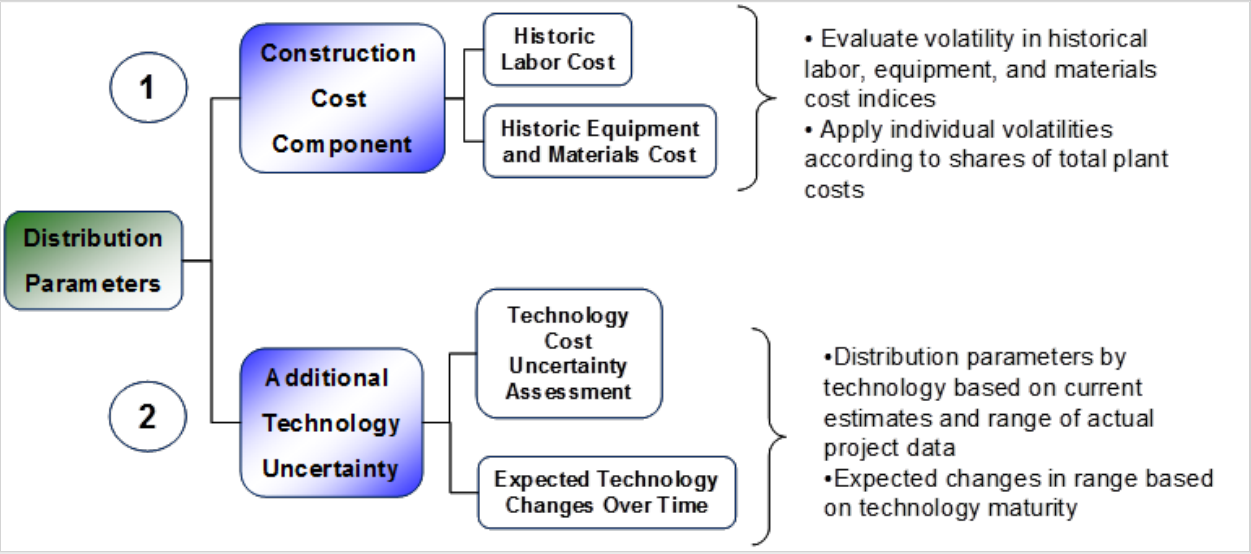
- For each iteration, the dispatch cost of gas and coal was calculated from the fuel stochastics and CO_2 stochastics, along with generic assumptions for VOM.
- If the gas-coal dispatch differential changes significantly enough to affect demand, the gas demand from the previous year was adjusted to reflect the corresponding change in demand.
    - Adjustment can happen in both directions
- A gas price delta was then calculated based on the defined gas demand – price relationship developed.

This gas price delta is added to the gas stochastic path developed from historic volatility to calculate an integrated CO_2 and natural gas stochastic price.

10.5.1.6 Capital Cost Stochastics

Pace developed the uncertainty distributions for the cost of new entry units by technology types, which were used in the Aurora dispatch model for determining the economic new builds based on market signals. The exhibit below describes the methodology at a high level:

Figure 10.22 – Pace Global's Capital Cost Stochastics Process



The methodology of develop the capital cost distributions is a two-step process:

Step 1:

Parametric Distribution:
Pace Global's subject matter experts provided a reference case forecast of $/KW all-in capital costs for different technology types. Along with it, high and low case forecasts were also developed.

The plant costs were broken down into four categories: Equipment, Materials, Labor, and Other. Historical data (from the Handy-Whitman Index) was used to estimate mean price changes and volatilities in these cost categories.

Suitable weights were allocated to each of these four categories. The weighted average of the historical mean and volatilities were then estimated.

Using the mean and volatility values, and sampling from an underlying standard normal distribution (which has a mean zero and variance one), the probability bands were constructed around the base case forecast.

Step 2:

Quantum Distribution:
This step captured the additional uncertainty associated with each technology. It also factored in the learning curve effects, improvements in technology over time, and other uncertain events.

The expert opinion based high and low cases were treated as one standard deviation from the mean. With this assumption, the variance values were calculated.

To determine the probability distributions, a log-normal distribution was assumed. This distribution was combined with the parametric distribution obtained in the previous step, to come up with the final set of distributions.

10.5.2 Rate Metric Ranking

Figure 10.23 – Aurora 20-Year Mean NPV $ Billion

Portfolio	20 Year NPV[57]	% above lowest cost
H: Heavy Gas	$ 3.02	
B: Heavy Gas	$ 3.03	0.0%
G: Gas & Solar	$ 3.06	1.0%
D: Gas & Wind	$ 3.07	1.4%
E: Heavy Gas	$ 3.10	2.5%
K: Diversified w/ Coal	$ 3.12	3.1%
N: Gas & Solar	$ 3.12	3.1%
O: Gas & Solar	$ 3.12	3.3%
L: Diversified w/ Coal	$ 3.15	4.1%
M: Diversified w/ Coal	$ 3.16	4.3%
C: Gas & Solar	$ 3.16	4.6%
F: Gas & Wind	$ 3.17	4.9%
A: Existing Portfolio	$ 3.21	6.3%
I: Stakeholder w/ Renewables	$ 3.86	27.6%
J: Stakeholder w/ Renewables	$ 4.21	39.3%

[57] The NPV of energy procurement is an indicative component of rates

Figure 10.24 – Aurora 20-Year Weighted Energy Procurement Cost[58]

Portfolio	20 Year $/kWh	% above lowest cost
H: Heavy Gas	0.064	
B: Heavy Gas	0.064	0.0%
G: Gas & Solar	0.065	1.0%
D: Gas & Wind	0.065	1.4%
E: Heavy Gas	0.066	2.5%
K: Diversified w/ Coal	0.066	3.1%
N: Gas & Solar	0.066	3.1%
O: Gas & Solar	0.066	3.3%
L: Diversified w/ Coal	0.067	4.1%
M: Diversified w/ Coal	0.067	4.3%
C: Gas & Solar	0.067	4.6%
F: Gas & Wind	0.067	4.9%
A: Existing Portfolio	0.068	6.3%
I: Stakeholder w/ Renewables	0.082	27.6%
J: Stakeholder w/ Renewables	0.089	39.3%

10.6 TRANSMISSION APPENDIX

10.6.1 Transmission and Distribution Planning Criteria

Vectren continually assesses the performance of its electric transmission and distribution systems to ensure safe and reliable service for its customers. The primary goals of Vectren'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 Vectren customers' needs during normal conditions and during a system contingency or set of contingencies;

[58] The NPV of energy procurement is an indicative component of rates

b) Minimizing thermal loadings on transmission facilities to be within operating limits during normal conditions and to be within emergency limits during contingency conditions;
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 Midcontinent Independent System Operator (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 Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC) and RF Reliability Standards for transmission planning.

10.6.2 MISO Regional Transmission Planning

The Midcontinent Independent System Operator (MISO) performs the North American Electric Reliability Corporation (NERC) functional role of Planning Coordinator on behalf of Vectren. In its NERC functional role of Transmission Planner, Vectren 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. Vectren is responsible for submitting the required modeling data to MISO pursuant to NERC MOD-032.

Vectren participates in MISO coordinated seasonal transmission assessments (CSAs) for spring, summer, fall and winter peak loads. 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. Vectren also participates in MISO Generator Interconnection and Transmission Service Requests planning processes as required.

Vectren 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 Vectren's Duff substation and Big Rivers Electric Corporation's Coleman EHV substation during the MTEP 2015 planning cycle. The project is expected to be in-service by the beginning of 2021. Pursuant to FERC Order 1000, MISO solicited competitive bids to construct the 345kV line. Vectren partnered with PSEG in submitting a proposal to MISO to construct the line. Vectren, as the incumbent transmission owner, will be responsible for the Duff substation modifications required for the project. The overall project cost is shared

according to MISO's Tariff. The project not only provides regional economic benefits, but also enhances grid reliability in the area of Vectren's Newtonville substation.

10.6.3 Annual Transmission Assessment

Vectren's most recent transmission assessment was completed in 2015. The study used the final NERC Multiregional Modeling Working Group (MMWG) 2014 Series Models, which includes the Vectren 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 33.6.0 software was used to conduct the assessment.

Vectren'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 2015, as previous dynamic studies were still deemed valid. Dynamic simulations were completed with MTEP-14 and the RF MMWG Seasonal Assessments.

The Vectren Bulk Electrical System (100kV and above) is expected to be stable and perform well over the next 10 years. 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, Vectren plans projects to mitigate the violations.

The loss of the two 138kV lines into Toyota substation results in the loss of service to the facility. A new 138kV line from Toyota substation to Scott Township substation is proposed. This line will also provide a second line into Scott Township substation, which is on a radial 138kV line. Scott Township substation provides voltage support for most of the load along the Highway 41 North corridor. This proposed line will also become a parallel path to the Francisco to Elliott 138kV line and increases post-contingent import capability.

Other notable contingencies (N-1-1) include the loss of load in the Mt. Vernon, IN area. The area is served by three 138kV lines. The outage of any two feeds causes voltage issues in the area and potential thermal overloads on the remaining line. The proposed customer-owned Co-Generation facility has the potential to reduce this large customer's load and eliminate this potential issue. Additional capacitor banks and upgrades could mitigate this issue as well. The only mentionable extreme contingency is also for the Mt. Vernon area 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 Vectren 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 are proposed as alternate feeds to reduce outage times.

- A new 69kV line to be installed between Mohr Rd and St. Wendell substations (scheduled in-service date of 12/31/2016).
- A new 69kV line to be installed between Boonville and Boonville Pioneer Substation (scheduled in-service date of 12/31/2018).
- Extend an existing 69kV line to provide a third source into the Jasper area from Dubois substation (scheduled in-service date of 12/31/2017).

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.

Toyota South, Roesner Road and Adam Street are new distribution substations currently proposed to meet load growth. The Adams Street substation project also facilitates 4kV to 12kV conversion projects.

SECTION 11
TECHNICAL APPENDIX ATTACHMENTS

Attachment 1.1 Non-Technical Summary

Confidential Attachment 1.2 2016 Vectren Technology Assessment Summary Table

Attachment 3.1 Stakeholder Materials

Attachment 4.1 2016 Vectren Long-Term Electric Energy and Demand Forecast Report

Attachment 4.2 2015 Vectren Hourly System Load Data

Attachment 4.3 2016 MISO LOLE Study Report

Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan

Confidential Attachment 5.2 CCGT Site Selection Report

Attachment 5.3 Cost of Energy Efficiency Programs

Confidential Attachment 5.4 CHP Market Potential Study

Attachment 7.1 IRP Portfolio Summary Report

Attachment 7.2 Balance of Loads and Resources

Confidential Attachment 7.3 Portfolio Input-Output Report

Attachment 7.4 Economic Impact Study - Economic Ripple Effects of Diversifying the Power Generation Portfolio

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 109
Culley East Ash Pond Extension Demonstration

VECTREN
A CenterPoint Energy Company

Vectren
P.O. Box 209
Evansville, IN 47702-0209

November 24, 2020

Sent electronically via File Transfer

Mr. Andrew Wheeler
Administrator, US EPA
1200 Pennsylvania Avenue, N.W.
Mail Code: 5304-P
Washington, D.C. 20460

Subject: Request for Site-Specific Alternative Deadline to Initiate Closure of CCR Surface Impoundment
Development of Alternative Capacity is Technically Infeasible Demonstration
SIGECO F.B. Culley Generating Station, Newburgh, Warrick County, Indiana

Dear Mr. Wheeler:

Southern Indiana Gas and Electric Company, Inc. (SIGECO) hereby submits this request for an extension to the "cease receipt" deadline for the F.B. Culley Generating Station (F.B. Culley) East Ash Pond pursuant to the *Development of Alternative Capacity is Technically Infeasible* criteria under 40 CFR § 257.103(f)(1).

The attached report has been prepared in accordance with the requirements of 40 CFR 257.103(f)(1) to demonstrate that obtaining alternative capacity for the CCR and non-CCR flows at the SIGECO F.B. Culley East Ash Pond is infeasible before the April 11, 2021 "cease receipt" deadline provided in 40 CFR § 257.101(a)(1). Accordingly, SIGECO is respectfully requesting an extension of the "cease receipt" deadline to March 1, 2023 for the East Ash Pond. The basis for this request is detailed in the attached document. To aid in your verification of completeness, a regulatory checklist summarizing where each regulatory requirement has been included in the report, immediately following the Table of Contents.

We trust this provides the information you need to process this application. As allowed and preferred by the agency, in lieu of hard copies of the demonstration packet, the submittal format is via email with a file transfer link to Kirsten Hillyer, Frank Behan, and Richard Huggins. Should you need additional information on this submittal, please don't hesitate to contact me at 812-491-4787 or Angela.Casbon-Scheller@centerpointenergy.com.

Sincerely,

Angela Casbon-Scheller
Manager, Environmental Operations
Power Generation

cc: Kirsten Hillyer (Hillyer.Kirsten@epa.gov)
Frank Behan (Behan.Frank@epa.gov)
Richard Huggins (Huggins.Richard@epa.gov)

AECOM Imagine it. Delivered.

Submitted to
Southern Indiana
Gas & Electric Company
(SIGECO)
One Vectren Square
Evansville, IN 47708

Submitted by
AECOM
525 Vine Street, Suite 1800
Cincinnati, Ohio 45202

November 24, 2020

Request for Site-Specific Alternative Deadline to Initiate Closure of CCR Surface Impoundment

Development of Alternative Capacity is Technically Infeasible Demonstration (40 CFR § 257.103(f)(1))

for the East Ash Pond at the F.B. Culley Generating Station

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Regulatory Checklist

Regulatory Reference	Description of Requirement	Report Section
257.103 (f)(1)(iv)(A)(1)	*A written narrative discussing the options considered both on and off-site to obtain alternative capacity for each Coal Combustion Residual (CCR) and/or non-CCR wastestreams, the technical infeasibility of obtaining alternative capacity prior to April 11, 2021, and the option selected and justification for the alternative capacity selected. The narrative must also include all of the following:*	**5.0**
257.103 (f)(1)(iv)(A)(1)(i)	*An in-depth analysis of the site and any site-specific conditions that led to the decision to select the alternative capacity being developed;*	**5.1.4**
257.103 (f)(1)(iv)(A)(1)(ii)	*An analysis of the adverse impact to plant operations if the CCR surface impoundment in question were to no longer be available for use; and*	**5.1.5**
257.103 (f)(1)(iv)(A)(1)(iii)	*A detailed explanation and justification for the amount of time being requested and how it is the fastest technically feasible time to complete the development of the alternative capacity;*	**5.1.6**
257.103 (f)(1)(iv)(A)(2)	*A detailed schedule of the fastest technically feasible time to complete the measures necessary for alternative capacity to be available including a visual timeline representation. The visual timeline must clearly show all of the following:*	**5.2**
257.103 (f)(1)(iv)(A)(2)(i)	*How each phase and the steps within that phase interact with or are dependent on each other and the other phases;*	**5.2**
257.103 (f)(1)(iv)(A)(2)(ii)	*All of the steps and phases that can be completed concurrently;*	**5.2**
257.103 (f)(1)(iv)(A)(2)(iii)	*The total time needed to obtain the alternative capacity and how long each phase and step within each phase will take; and*	**5.2**
257.103 (f)(1)(iv)(A)(2)(iv)	*At a minimum, the following phases: Engineering and design, contractor selection, equipment fabrication and delivery, construction, and start up and implementation.;*	**5.2**
257.103 (f)(1)(iv)(A)(3)	*A narrative discussion of the schedule and visual timeline representation, which must discuss all of the following:*	**5.2**
257.103 (f)(1)(iv)(A)(3)(i)	*Why the length of time for each phase and step is needed and a discussion of the tasks that occur during the specific step;*	**5.2**
257.103 (f)(1)(iv)(A)(3)(ii)	*Why each phase and step shown on the chart must happen in the order it is occurring;*	**5.2**
257.103 (f)(1)(iv)(A)(3)(iii)	*The tasks that occur during each of the steps within the phase; and*	**5.2**
257.103 (f)(1)(iv)(A)(3)(iv)	*Anticipated worker schedules*	**5.2.2.8**
257.103 (f)(1)(iv)(A)(4)	*A narrative discussion of the progress the owner or operator has made to obtain alternative capacity for the CCR and/or non-CCR wastestreams. The narrative must discuss all the steps taken, starting from when the owner or operator initiated the design phase up to the steps occurring when the demonstration is being compiled. It must discuss where the facility currently is on the timeline and the efforts that are currently being undertaken to develop alternative capacity.*	**5.3**
257.103 (f)(1)(iv)(B)	*To demonstrate that the criteria in paragraph (f)(1)(iii) of this section have been met, the owner or operator must submit all of the following:*	**6.0**

Regulatory Reference	Description of Requirement	Report Section
257.103 (f)(1)(iv)(B)(1)	*A certification signed by the owner or operator that the facility is in compliance with all of the requirements of this subpart;*	**6.1**
257.103 (f)(1)(iv)(B)(2)	*Visual representation of hydrogeologic information at and around the CCR unit(s) that supports the design, construction and installation of the groundwater monitoring system. This includes all of the following:*	**6.2**
257.103 (f)(1)(iv)(B)(2)(i)	*Map(s) of groundwater monitoring well locations in relation to the CCR unit(s);*	**6.2.1**
257.103 (f)(1)(iv)(B)(2)(ii)	*Well construction diagrams and drilling logs for all groundwater monitoring wells; and*	**6.2.2**
257.103 (f)(1)(iv)(B)(2)(iii)	*Maps that characterize the direction of groundwater flow accounting for seasonal variations;*	**6.2.3**
257.103 (f)(1)(iv)(B)(3)	*Constituent concentrations, summarized in table form, at each groundwater monitoring well monitored during each sampling event;*	**6.3**
257.103 (f)(1)(iv)(B)(4)	*A description of site hydrogeology including stratigraphic cross-sections;*	**6.4**
257.103 (f)(1)(iv)(B)(5)	*Any corrective measures assessment conducted as required at 257.96*	**6.5**
257.103 (f)(1)(iv)(B)(6)	*Any progress reports on corrective action remedy selection and design and the report of final remedy at selection required a 257.97 (a)*	**6.6**
257.103 (f)(1)(iv)(B)(7)	*The most recent structural stability assessment required at 257.73 (d)*	**6.7**
257.103 (f)(1)(iv)(B)(8)	*The most recent safety factor assessment required at 257.73 (e)*	**6.8**

Acronyms

ASD	Alternative Source Demonstration
BOD	Biochemical Oxygen Demand
BOP	Balance of Plant
CbR	Closed (or Closure) by Removal
CCR	Coal Combustion Residuals
CFR	Code of Federal Regulations
CiP	Closed (or Closure) in Place
CRW	Clarified River Water
DCS	Distributed Control System
ELG	Effluent Limitation Guidelines
EPA	United States Environmental Protection Agency
F.B. Culley	F.B. Culley Generating Station
FGD	Flue Gas Desulfurization
GPD	Gallons Per Day
GWPS	Groundwater Protection Standards
IDEM	Indiana Department of Environmental Management
IFC	Issued for Construction
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
MGD	Million Gallons per Day
MM	Million
MSL	Mean Sea Level
MW	Megawatt
NPDES	National Pollutant Discharge Elimination System
OLQ	Office of Land Quality
POTW	Publicly Owned Treatment Works
RFP	Request for Proposal
SCC	Submerged Chain Conveyor
SDE	Spray Dryer Evaporator
SIGECO	Southern Indiana Gas and Electric Company
SSLs	Statistically Significant Levels
TSS	Total Suspended Solids
WWTF	Wastewater Treatment Facility
ZLD	Zero-Liquid Discharge

1 Executive Summary

Southern Industrial Gas and Electric Company (SIGECO) owns and operates the F.B. Culley Generating Station (F.B. Culley Generating Station or F.B. Culley) located in Warrick County, Indiana, southeast of Newburgh, Indiana. F.B. Culley Generating Station currently operates the East Ash Pond, a unit that receives both Coal Combustion Residual (CCR) and non-CCR flows associated with the operation of two coal-fired generating units; Unit 2 at 100 megawatts (MW) and Unit 3 at 287 MW. The East Ash Pond is a currently operating surface impoundment which is planning for closure in accordance with the requirements of the United States Environmental Protection Agency's (EPA) Final CCR Rule (40 Code of Federal Regulations (CFR) 257, Subpart D or Federal CCR Rule). The CCR Rule (following the Part A updates) requires SIGECO to cease discharge of CCR and non-CCR wastestreams into the East Ash Pond as soon as technically feasible, but no later than April 11, 2021, or seek appropriate extensions under 40 CFR § 257.103 to continue operating. As described in this document, SIGECO is requesting an extension of the April 11, 2021 "cease flow" deadline for operation of the East Ash Pond.

For continued operation of the East Ash Pond beyond April 11, 2021, two extension mechanisms are available under the final Part A: (1) *Development of Alternative Capacity is Technically Infeasible* (40 CFR § 257.103(f)(1)) or (2) *Permanent Cessation of a Coal-Fired Boiler(s) by a Date Certain* (40 CFR § 257.103(f)(2)). SIGECO has prepared this document to demonstrate that obtaining alternative capacity for the CCR and non-CCR flows at the F.B. Culley East Ash Pond is infeasible before the April 11, 2021 deadline, and additional time is needed to operate the East Ash Pond until alternative capacity becomes available under the fastest technically feasible timeline.

Eight alternative capacity options were identified and evaluated based on feasibility and schedule including repurposing existing lined facilities, constructing a new pond, constructing a new wastewater treatment facility, and transporting wastestreams to area treatment facilities. Prior to Part A, SIGECO has been actively implementing a plan for redirection of non-CCR to a new lined contact stormwater pond (nearing construction completion) as well as completing dry bottom ash conversion for Unit 3. In addition, SIGECO has determined the construction of an additional new lined CCR-Rule compliant pond for alternative capacity to allow the cessation of CCR flows to the East Ash Pond is the fastest feasible option for obtaining alternative capacity. As described in this demonstration, these ponds will serve both CCR and non-CCR flows currently managed by the East Ash Pond. The combination of these activities (and others described within the demonstration) is believed to represent the fastest feasible timeline for obtaining alternative capacity. Engineering and design associated with these improvements is ongoing, and the systems are expected to be operational on or prior to the requested "cease flow" date of March 1, 2023.

2 Demonstration Purpose and Objectives

This document has been prepared in accordance with the requirements 40 CFR § 257.103(f)(1) to demonstrate that obtaining alternative capacity for CCR and non-CCR flows at the SIGECO F.B. Culley East Ash Pond is infeasible before the April 11, 2021 “cease receipt” deadline provided in 40 CFR § 257.101(a)(1). Accordingly, SIGECO is respectfully requesting an extension to the deadline for East Ash Pond operations pursuant to the Development of Alternative Capacity is Technically Infeasible criteria under 40 CFR § 257.103(f)(1). This document provides the requested information to support this demonstration.

3 Organization of the Demonstration

For ease of review and verification of completeness, this demonstration has been structured consistent with the specific requirements and criteria under 40 CFR § 257.103(f)(1)(iv). The document structure and contents of each section are as follows:

Section 1 – Executive Summary – This section provides an overview of the document.

Section 2 – Demonstration Purpose and Objectives – This section provides a brief discussion of the document purpose.

Section 3 – Organization of the Demonstration – This section provides a discussion of the document outline and organization, indicating where the various regulatory criteria are addressed.

Section 4 – Facility and CCR Unit Background and Description – This section provides background information associated with the generating station, its current operating scenario, and the CCR unit.

Section 5 – Work Plan for Alternative Capacity – This section addresses the requirements for a work plan described in 40 CFR § 257.103(f)(1)(iv)(A), and includes the following key subsections:

- **Section 5.1 – Evaluation of On-site and Off-site Options for Alternative Capacity –** This section provides a detailed Work Plan for obtaining Alternative Capacity consisting of a narrative discussion of options considered, technical infeasibility demonstrations, and a justification of the option selected (40 CFR § 257.103(f)(1)(iv)(A)(1)).

- **Section 5.2 – Detailed Schedule and Narrative Discussion** – This section provides a detailed schedule of the fastest technically feasible time to complete the measures necessary and a narrative discussion describing the schedule and timeline considerations (40 CFR § 257.103(f)(1)(iv)(A)(2 and 3)).

- **Section 5.3 – Progress Toward Alternative Capacity** - This section provides a narrative discussion of the progress made to obtain alternative capacity thus far (40 CFR § 257.103(f)(1)(iv)(A)(4)).

Section 6 – Compliance Certification and Additional Information – This section provides a signed certification that the facility is operating in compliance with this subpart and a summary reference to the requested hydrogeologic and other information (40 CFR § 257.103(f)(1)(iv)(B)). The requested items are provided in appendices.

The recent “A Holistic Approach to Closure Part A: Deadline to Initiate Closure” (Part A) revision to the Federal CCR Rule requires that demonstrations be submitted to EPA for approval no later than November 30, 2020. Following the submission of this demonstration, SIGECO will place a Notice of Intent to apply for a site-specific alternative to initiation of closure due to development of alternative capacity infeasible, along with a copy of the demonstration, into its operating record and onto the SIGECO CCR Compliance web page (https://www.vectren.com/reporting/ccr) as required by 40 CFR § 257.105(i)(14) and 40 CFR § 257.106(i)(14), respectively.

4 Facility and CCR Unit Background and Description

A discussion of the facility, current and future operational scenario, and CCR unit background is provided in the following sections.

4.1 Facility Description and Future Operations

SIGECO owns and operates F.B. Culley located in Warrick County, Indiana, southeast of Newburgh, Indiana (see attached **Figure 1**). F.B. Culley is located along the north bank of the Ohio River, and Little Pigeon Creek is situated along the southeastern-eastern boundary of the facility. Within its operational life, F.B. Culley has operated two (2) CCR surface impoundments referred to as the West Ash Pond and the East Ash Pond (see attached **Figure 2**). However, only the East Ash Pond is currently in operation receiving both CCR and non-CCR wastestreams. The West Ash Pond (described further below) is nearing the completion of closure. Closure of the West Ash Pond is on schedule to be complete by December 17th, 2020.

The East Ash Pond is located in the southeasternmost area of the station and is approximately 10 acres in size. The East Ash Pond was commissioned in approximately 1971 and operates as an unlined CCR impoundment. The East Ash Pond currently receives both CCR and non-CCR flows associated with the operation of two coal-fired generating units: Unit 2 (100 MW) and Unit 3 (287 MW). It should be noted that Unit 1 was previously retired in 2005.

As mentioned above, closure activities for the West Ash Pond are currently underway and nearing completion. As such, neither CCR nor non-CCR flows are currently managed and treated by the West Ash Pond. In order to facilitate closure of the West Ash Pond under the provisions of the Federal CCR Rule, it should be noted that a separate previously-completed project addressed redirection of West Ash Pond flows to the East Ash Pond. Under a closure plan approved by the Indiana Department of Environmental Management (IDEM), a portion of the West Ash Pond is being Closed by Removal (CbR) and a portion of the pond is Closed in Place (CiP) with a final cover system meeting the requirements of the Federal CCR Rule. The CbR portion of the West Ash Pond closure includes construction of a lined Contact Stormwater Pond. As discussed throughout this demonstration, at a future date (July 1, 2021) this lined Contact Stormwater Pond will also manage non-CCR flows currently treated by the East Ash Pond.

A significant amount of planning and engineering is currently underway at F.B. Culley under both the CCR and the ELG rules related to future unit operation and management of flows. There are also a number of current regulatory milestones associated with these efforts. As discussed in the recently issued Integrated Resource Plan (IRP) report, Unit 2 is currently slated for retirement by the end of 2023 and current bottom ash and flue gas desulfurization FGD wastewater streams associated with Unit 2 will cease in conjunction with this unit retirement. It is anticipated that Unit 3 will remain in operation past 2023 and projects are currently underway for dry bottom ash conversion (completed November 2020 prior to the milestone date of December 31, 2020) as well as implementation of a zero-liquid discharge (ZLD) process for management of FGD-related wastewaters (scheduled completion by July 1, 2023). The modification (and associated schedule milestones) for Unit 3 bottom ash transport water (December 31, 2020) is the result of a mandate in the facility's current National Pollutant Discharge Elimination System (NPDES) to cease the discharge of bottom ash transport water no later than December 31, 2020. Additionally, the modifications for the FGD-related wastewaters is the result of a mandate to meet new limits by February 1, 2021, unless the facility commits to retiring Unit 3 or installing a ZLD process, in which case a later compliance date that is no later than December 31, 2023, may be sought. An Order (Cause No. 45052) from the Indiana Utility Regulatory Commission (IURC) was issued on April 24, 2019, in which the IURC authorized the capital expenditure for the ZLD technology on Unit 3 (See **Appendix A**). Issuance of this Order was a necessary step in determining the remaining

useful life of Unit 3 and the consequential management of FGD-related wastewater flow. While engineering associated with implementation of ZLD technology is currently underway, SIGECO is also reviewing potential impacts of the recently published (October 13, 2020) ELG Reconsideration Rule and upcoming 2022 IRP study on the future operation of Unit 3. For this reason and as discussed in this demonstration, additional alternative capacity options are being implemented (representing the fastest technically feasible time) that will also address remaining Unit 3 FGD-related wastewaters while SIGECO evaluates its potential compliance options for Unit 3 under the new ELG Reconsideration Rule. As mentioned previously, non-CCR flows currently managed by the East Ash Pond will be diverted to the new lined Contact Stormwater Pond currently under construction within the footprint of the former West Ash Pond which is nearing completion. Design activities for this non-CCR flow diversion are currently underway and the systems will be operational by July 1, 2021.

4.2 CCR Unit Description

The East Ash Pond was commissioned in approximately 1971 and currently operates as an unlined CCR surface impoundment. Earthen embankments were constructed along the south and east sides of the impoundment. Structural fill from the original construction of the F.B. Culley Generating Station in the 1950s was used to construct the earthen embankment along the east and south sides of the unit, forming the East Ash Pond. The east embankment intersects a natural hillside on the east end of the north side of the impoundment. The perimeter of the embankment is approximately 1,200-feet long, 30-feet high, with exterior side slopes covered with grassy vegetation. The surface area of the impoundment is approximately 9.8 acres and the unit has a normal water operating level of 386 feet above mean sea level (MSL).

Following promulgation of the Federal CCR Rule, SIGECO began working with consultants (AECOM and Haley & Aldrich) to evaluate the East Ash Pond's compliance with the new CCR Rule requirements. The East Ash Pond was certified to be compliant with Federal CCR Rule stability and safety factor criteria. The East Ash Pond is also compliant with the wetlands, fault area, seismic impact zone, and unstable area location restrictions. However, the East Ash Pond did not achieve the uppermost aquifer separation criteria. Groundwater monitoring results associated with the East Ash Pond indicate the data exhibits statistically significant levels (SSLs) of molybdenum and arsenic above Groundwater Protection Standards (GWPS). However, arsenic was subsequently addressed by a successful Alternative Source Demonstration (ASD) (**Appendix H**). Given that the unit is unlined, the East Ash Pond is required to cease CCR and non-CCR flows by April 11, 2021 (under the provisions of the recently effective Part A) and either initiate closure or seek appropriate extensions for continued short-term operation.

4.3 Extension Mechanism Selection

The East Ash Pond will operate beyond April 11, 2021, because no alternative capacity currently exists (either on or off-site) and it is infeasible to obtain alternative capacity prior to the April 11, 2021 "cease flow" deadline. For continued operation of the East Ash Pond beyond April 11, 2021, two extension mechanisms are available under the final Part A: (1) Development of Alternative Capacity is Technically Infeasible (40 CFR § 257.103(f)(1)) or (2) Permanent Cessation of a Coal-Fired Boiler(s) by a Date Certain (40 CFR § 257.103(f)(2)). Key considerations for each of these provisions and the basis for extension selection are outlined below.

1) *Development of Alternative Capacity is Technically Infeasible*: Under this provision, Owner/Operators are required to demonstrate to EPA that obtaining alternative capacity on-site or off-site is infeasible before April 11, 2021, and that additional time is needed to secure additional capacity. In summary, the demonstration must provide information and technical justification that no alternative capacity exists on-site or off-site and must provide a detailed workplan and schedule that includes technical and narrative discussions of how F.B. Culley will obtain alternative capacity. Following public comment and EPA approval, this provision allows for approval of continued operations up to October 15th, 2023 (for non-eligible unlined CCR surface impoundments) or October 15th, 2024 (for eligible unlined CCR surface impoundments). Under the provisions of Part A, the East Ash Pond is a non-eligible unlined CCR surface impoundment.

2) *Permanent Cessation of a Coal-Fired Boiler(s) by a Date Certain*: Under this provision, a CCR unit may continue to receive flows if the owner or operator also commits to coal-fired boiler closure. As discussed in Part A, the facility must commit to coal-fired boiler retirement and cease flows/complete CCR unit closure by October 17th, 2023 (for units less than or equal to 40 acres). Because it is currently anticipated that Unit 3 will continue operation beyond October 17, 2023, F.B. Culley would not qualify for this extension mechanism and it is not discussed further in this demonstration.

Based on the considerations above, SIGECO has prepared this extension based on the requirements for the *Development of Alternative Capacity is Technically Infeasible* extension provision of Part A. As discussed throughout this demonstration, this selection meets the following criteria for *Development of Alternative Capacity is Technical Infeasible* as referenced in 40 CFR § 257.103(f)(1):

- No alternative disposal capacity is available on or off-site (40 CFR § 257.103(f)(1)(i))
- CCR and non-CCR waste streams must continue to be managed in the CCR surface impoundment because it is technically infeasible to complete the measures necessary to obtain alternative disposal capacity either on or off-site of the facility by April 11, 2021 (40 CFR § 257.103(f)(1)(ii)).

5 Work Plan for Alternative Capacity (40 CFR § 257.103(f)(1)(iv)(A)(1))

The Part A demonstration criteria presented in 40 CFR § 257.103(f)(1)(iv)(A)(1) requires a written narrative discussing the options considered both on- and off-site to obtain alternative capacity for each CCR and/or non-CCR waste stream, the technical infeasibility of obtaining alternative capacity prior to April 11, 2021, and the option selection and justification for the alternative capacity selected. The options considered are further discussed in the following sections.

5.1 Evaluation of On-site and Off-site Options for Alternative Capacity

The East Ash Pond has a current storage capacity of 28.2 acre-feet (9,175,000 gallons) and serves a primary role for plant operations with key functions including solids removal by settling and hydraulic surge. The East Ash Pond, as currently operating, receives an average of approximately 1.65 million gallons per day (MGD) of influent from various plant sources. Several of the flows to the East Ash Pond from Units 2 and 3 (such as FGD wastewater-related flows) are comingled. Unit 1 at F.B Culley Station was retired in 2005; however, the basement sump that serves Units 1 & 2 remains in service.

The flowrates of the primary streams are summarized in **Table 1**.

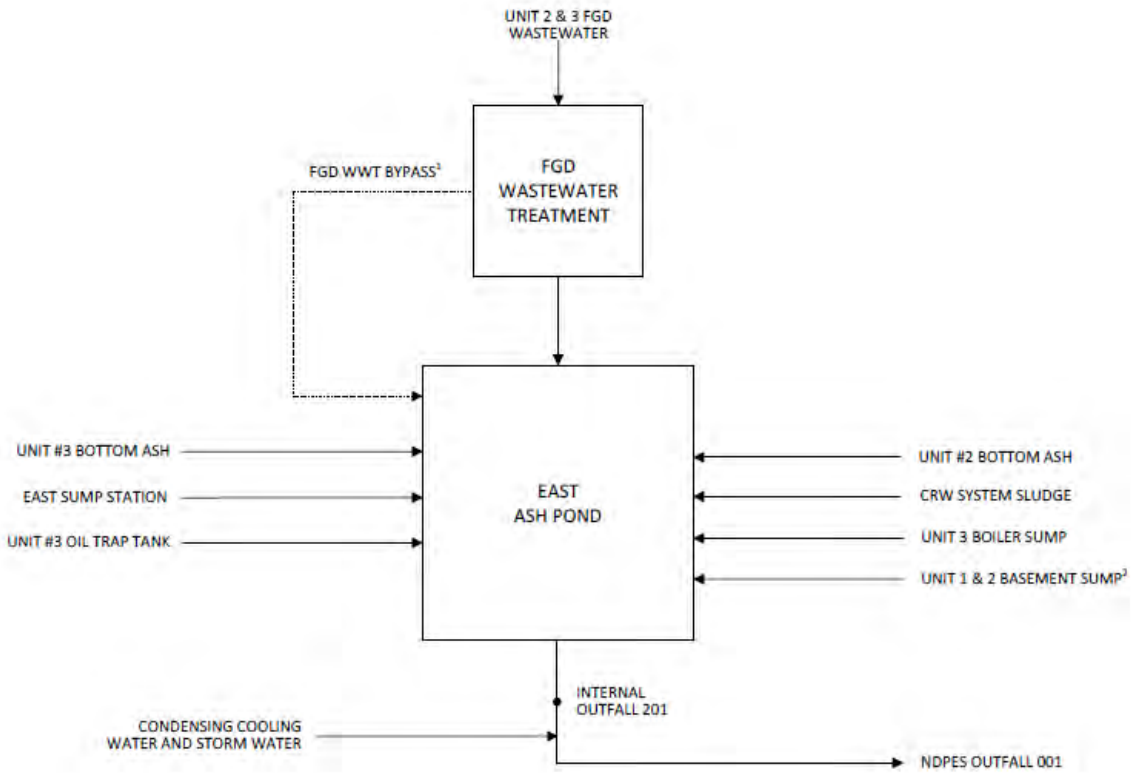
Table 1: East Ash Pond Inflows

CCR Flows			
Source	**MGD**	**Current Management**	**Future Management**
Unit 2 Bottom Ash Sluice Water	0.138	East Ash Pond	New Lined CCR Pond
Unit 3 Bottom Ash Sluice Water	0.321	East Ash Pond	Dry conversion complete 12/31/2020
Unit 2 FGD Wastewater	0.095	East Ash Pond	New Lined CCR Pond
Unit 3 FGD Wastewater			
Non- CCR Flows			
Clarified River Water (CRW) Sludge	0.035	East Ash Pond	New Lined Contact Stormwater Pond
Unit 3 Boiler Sump	0.173	East Ash Pond	New Lined Contact Stormwater Pond
East Sump Station	0.792	East Ash Pond	New Lined Contact Stormwater Pond
Units 1 & 2 Basement Sump	0.088	East Ash Pond	New Lined Contact Stormwater Pond
Mix Tank/ Unit 3 Oil Trap	0.0123	East Ash Pond	New Lined Contact Stormwater Pond
Total	**1.65**		

[1]Note Unit 1 has previously been retired.

The flows into the East Ash Pond are discharged through Internal Outfall 201, then combined with condenser cooling water and stormwater and discharged through NPDES Outfall 001. A block flow diagram of the current flows to and from the East Ash Pond is shown in **Figure 3**.

Figure 3: Flow Diagram of Current Flows to/from East Ash Pond



[1.] FGD Wastewater Treatment (WWT). Bypass for emergency use only. [2.] Note Unit 1 was retired in 2005.

The cessation of CCR and non-CCR flows to the East Ash Pond requires alternative capacity to replace the operational functions of the pond, or the plant must be modified to operate without the East Ash Pond. Primary functions of the East Ash Pond that must be replaced include removal of solids and hydraulic storage. As required by Part A, both on-site and off-site options were evaluated as potential paths to alternative capacity. The following sections detail the options considered and justification for the selected alternative as the fastest feasible timeline for obtaining the needed alternative capacity.

When considering the current operations at the F.B. Culley and the process for obtaining alternative capacity for the East Ash Pond, the following considerations are key:

- **Unit 3 Bottom Ash Flows** – The East Ash Pond has managed Unit 3 Bottom Ash Sluice Water (0.321 MGD). The facility's NPDES permit requires elimination of these flows by December 31, 2020 and a project was completed in November 2020 to convert Unit 3 bottom ash handling operations to a dry handling system using a submerged chain conveyor (SCC). Because this flow has been eliminated prior to the April 11, 2021 "cease flow" deadline, alternative capacity for the Unit 3 Bottom Ash Sluice Water is not discussed further in this report.

- **Unit 2 & 3 FGD-Related CCR Flows** – The current CCR flows to the East Ash Pond include Unit 2 Bottom Ash Sluice Water (0.138 MGD) and Unit 2 and 3 FGD Wastewater (0.095 MGD). The process of obtaining alternative capacity for the non-CCR and Unit 2 & 3 FGD-related wastewater flows is considered "critical path" and the alternative capacity discussions within this report will focus primarily on these flows.

- **Unit 2 Bottom Ash Flows** – The East Ash Pond currently manages Unit 2 bottom ash sluice water at an average flow rate of 0.138 MGD. It is worth noting that the capacity factor for Unit 2 was 15.3% in 2019, 32.1% in 2018, and 22.2% in 2017. Whereas it is anticipated that retirement of Unit 2 will occur by the end of 2023, this flow has also been considered in this evaluation of alternative capacity and fastest feasible timeline. However, feasible options for alternate capacity of this bottom ash stream that can be completed before October 15, 2023 are limited and include only an alternative lined CCR pond or a SCC (similar to that being installed on Unit 3). Complications associated with installation of a SCC for the physical configuration of Unit 2 renders this option technically infeasible in a timeframe less than 36 months. For this reason, this technical evaluation has focused on the critical path of addressing Unit 2 and 3 FGD-related wastewaters. Accordingly, each option has also been given consideration for potential management of the Unit 2 bottom ash wastestream.

The options and process for obtaining alternative capacity for the non-CCR and CCR flows, (FGD-related wastewater flows, and Unit 2 bottom ash flows) is discussed in the following sections.

Non-CCR Flows

Since approximately 2017, efforts have been in place for the redirection of non-CCR flows managed by the East Ash Pond to the lined contact stormwater pond being constructed as part of the West Ash Pond closure activities. These non-CCR wastestreams are summarized in **Table 2**.

Table 2. Redirected East Ash Pond Non-CCR Inflows

Non- CCR Flows		
Source	**MGD**	**Future Management**
Clarified River Water (CRW) Sludge	0.035	New Lined Contact Stormwater Pond
Unit 3 Boiler Sump	0.173	New Lined Contact Stormwater Pond
East Sump Station	0.792	New Lined Contact Stormwater Pond
Unit 1 & 2 Basement Sump[1]	0.088	New Lined Contact Stormwater Pond
Mix Tank/ Unit 3 Oil Trap	0.0123	New Lined Contact Stormwater Pond
Total	**1.100**	

1. Note Unit 1 is retired as of 2005.

Based on commitments to IDEM as part of a variance from a requirement of the 2015 CCR rule (40 CFR 257.101(a)(1)), which is currently still in effect in Indiana, engineering is currently underway and these non-CCR flows to the East Ash Pond are scheduled to cease by July 1, 2021, following construction of infrastructure to redirect these flows to the new lined Contact Stormwater Pond. Re-routing of these non-CCR streams to the new Contact Stormwater Pond was underway well before the final Part A and represents the fastest technically feasible alternative for management of these non-CCR flows.

Unit 2 and 3 FGD-Related Wastewater Stream and Unit 2 Bottom Ash Stream

As mentioned previously, it is SIGECO's current intent to retire Unit 2 by the end of 2023 as discussed in the recent IRP. Nevertheless, Part A requires evaluation of the "fastest technically feasible timeline" for obtaining alternative capacity. For this reason, both Unit 2 and Unit 3 flows managed by the East Ash Pond have been considered in this evaluation of alternative capacity. Considering the current activities for management of non-CCR flows in the new lined Contact Stormwater Pond and dry conversion of Unit 3 bottom ash system, the remaining flows to the East Ash Pond are the FGD wastewater stream from Unit 2 and Unit 3, as well as the Unit 2 bottom ash

wastestream. As mentioned previously, this evaluation focuses on alternatives for management of the Unit 2 and 3 FGD-related wastewaters, but also gives consideration to management of Unit 2 bottom ash flows within each alternative.

Units 2 and 3 are served by a common FGD system producing one wastewater stream discharge to the East Ash Pond. The FGD wastewater discharged to the East Ash Pond is nominally 95,000 gallons per day (GPD). In evaluating alternative capacity options for the FGD wastewater stream, the NPDES permit requirements for this discharge were considered. New numeric effluent limitations for the FGD wastewater discharge take effect in the near future unless the facility commits to retire Unit 3 or proceed with ZLD for FGD-related wastewaters, in which case, a request can be made to modify the NPDES compliance date to not later than December 31, 2023. As SIGECO intends to operate Unit 3 into the future (past December 31, 2023), the focus on obtaining alternative capacity has been directed toward a ZLD system for FGD-related wastewaters. As discussed previously, the receipt of the IURC Order in April 2019, which approved the capital investment, was a necessary step in the process of determining the means of managing the FGD-related wastewater flow. While the order approved the capital expenditure for Unit 3, the future of Unit 2 was subject to the outcome of the required 2019-2020 IRP study and subsequent approvals. Nevertheless, Unit 2 flows have been addressed in this evaluation based on the consideration of ceasing flows to the East Ash Pond and the fastest technically feasible timeline for completing this process.

The following alternative options were considered for the FGD wastewater flows:

1. Alternative 1 – Repurposing Existing Lined Facilities.
2. Alternative 2 – Construction of a New On-site CCR Rule-Compliant Pond – Area to North of New Lined Contact Stormwater Pond
3. Alternative 3 – Construction of a New On-site CCR Rule-Compliant Pond – Area to North of East Ash Pond
4. Alternative 4 - Alternative Capacity Off-site
5. Alternative 5 – Temporary Wastewater Treatment Facility
6. Alternative 6 – Brine Concentrator
7. Alternative 7 – Membrane Separation
8. Alternative 8 – Wastewater Spray Dryer

Descriptions of each treatment alternative and discussion of feasibility at F.B. Culley are provided in the sections below.

5.1.1 On-site Alternative Capacity – Pond Systems

Alternatives 1, 2, and 3 consider on-site alternatives involving repurposing of existing ponds or construction of a new pond system. These options are discussed further in the following sections.

Alternative 1 – Repurposing Existing Lined Facilities

For completeness in the alternative capacity option development process, consideration was given to repurposing existing lined facilities for management of FGD-related wastewater flows from Unit 2 and 3 and bottom ash flows from Unit 2. The only potential option would be management of these wastewater flows in the new lined Contact Stormwater Pond as no other ponds currently exist on-site. However, several considerations and limitations render this option technically infeasible. First, FGD wastewater flows and the Unit 2 bottom ash flow would be considered a CCR flow and the new lined Contact Stormwater Pond (currently nearing completion of construction and on schedule to be in service by the end of 2020) was not designed for management of CCR flows and would not meet the requirements for a composite liner system under the Federal CCR Rule (40 CFR § 257.72). Significant retrofit of the liner system would be required that would take considerable time and not be achievable by the July 1, 2021 regulatory milestone contained in the IDEM variance for continued use of the East Ash Pond. In addition, this new lined stormwater pond has not been sized for the flows associated with the FGD-related wastewater streams and Unit 2 bottom ash stream. Accommodation of these streams within the new lined Contact Stormwater Pond would require significant expansion to provide the settling capacity required to manage and treat these additional CCR

flows. Further, this new lined Contact Stormwater Pond was included as a component of the IDEM closure plan approval for the West Ash Pond. This option would require both modification of the current closure plan approval for the West Ash Pond (6-month process) as well as an approval from the IDEM Office of Land Quality (OLQ) for operation of a new CCR surface impoundment (12-month process). In addition to these timeline considerations, a CCR compliant monitoring well network would also require installation and monitoring prior to construction/permit approval. For these regulatory and technical reasons, this option is considered technically infeasible within the available timeframe.

Alternative 2 – Construction of a New On-site CCR Rule-Compliant Pond – Area to North of New Lined Contact Stormwater Pond

Construction of a new lined CCR Pond (impoundment) in the area to the north of the new lined Contact Stormwater Pond has been evaluated and is the preferred alternative for this analysis as it represents the fastest technically feasible timeframe to obtain alternative capacity and flow cessation to the East Ash Pond. The (CbR) *Excavation Area* of the West Ash Pond closure (area currently complete) has been evaluated as a potential location for a new lined CCR Pond. The new pond would be constructed immediately north of the lined Contact Stormwater Pond that is nearing construction completion and is on schedule to be in service by the end of 2020. In concept, the new lined CCR Pond would be constructed upgradient of and discharge through the lined Contact Stormwater Pond for polishing and flow equalization considerations.

In this proposed area, the CCR materials from the former West Ash Pond footprint have been completely removed and verified, and structural fill has been placed over the excavation grades to create a network of stormwater conveyance channels that manage clean (non-contact) stormwater flows from contributing drainage areas across the plant property. These clean stormwater flows are conveyed through a piping network and ultimately discharged through a NPDES permitted stormwater outfall.

The new lined CCR Pond would be sized for management of FGD-related wastewater flows from Unit 2 and 3 and Bottom Ash discharge flows from Unit 2. Since these flows would be considered CCR flows, the new lined CCR Pond will need to meet the requirements for a composite liner system under the Federal CCR Rule (40 CFR § 257.72) as well as achieve the location restrictions of 40 CFR § 257.60-64. Based on a fatal flaw analysis of these requirements, the potential location (**Figure 4)** is expected to be suitable for construction of a new CCR Rule-compliant surface impoundment.

Figure 4: Potential Location of New CCR Rule-Compliant Pond

As depicted in **Figure 4**, approximately 7 acres of land north of the new lined Contact Stormwater Pond is currently available for a new pond. This would require the clean stormwater flow network to be modified during construction of the new pond in this location. To create an equivalent settling capacity provided by the East Ash Pond, a 7-day retention period is being assumed for the combined Unit 2 bottom ash and Unit 2 and 3 FGD wastewater flows. Since the daily flow is cumulatively 233,000 gallons, approximately 1.63 million gallons (5 acre-feet) of storage is necessary to provide the required settling. To evaluate the sizing requirements for the pond, the volume of a rectangular pond was calculated as follows:

i) This pond was assumed to have the shape of an upside-down rectangular truncated pyramid, with 3:1 H:V (horizontal : vertical) interior side slopes, and a conservative depth of 5 feet that provides a minimum freeboard of 2 feet.

ii) The total area of the pond would be approximately 2 acres and the outer boundary of the pond would be 440 feet by 200 feet, sloping down to a rectangle bottom 410 feet by 170 feet on each side. These dimensions would conservatively provide a total settling volume of approximately 3.10 million gallons (9.5 acre-feet) including freeboard.

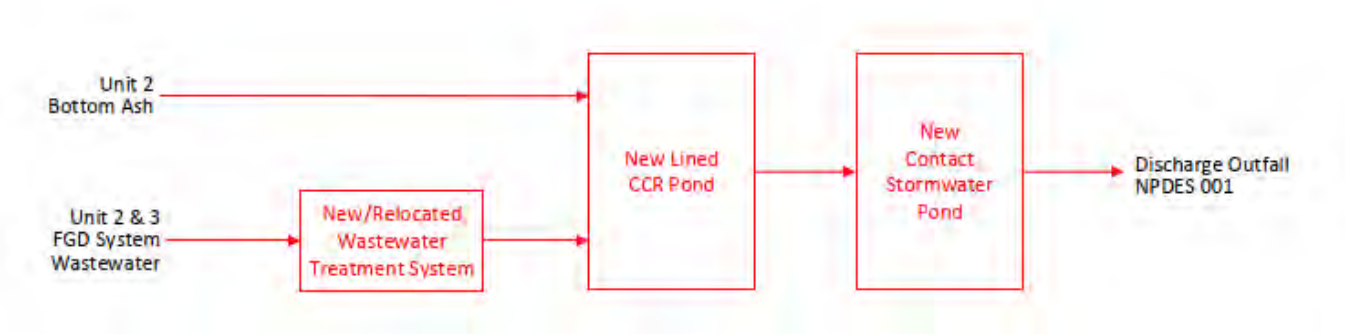
Based on these considerations, construction of a pond of sufficient size to address the CCR flows managed by the East Ash Pond would be technically feasible.

Pursuant to 40 C.F.R. § 257.60(a), new CCR landfills, existing and new CCR surface impoundments, and all lateral expansions of CCR units must be constructed with a base that is located no less than 1.52 meters (five feet) above

the upper limit of the uppermost aquifer, or must demonstrate that there will not be an intermittent, recurring, or sustained hydraulic connection between any portion of the base of the CCR unit and the uppermost aquifer due to normal fluctuations in groundwater elevations (including the seasonal high water table). Installation of wells to address CCR Rule requirements (as needed) and groundwater monitoring to establish water levels will be conducted to provide a minimum elevation for the base of the future CCR-pond liner system. In the event the water levels prohibit a 1.52 meter separation while maintaining necessary storage capacity, the liner system will be designed in a manner that insures no hydraulic connection between any portion of the base of the unit and the uppermost aquifer.

The existing CCR flows to the East Ash Pond, Unit 2 and 3 FGD wastewater and Unit 2 bottom ash sluice, will be re-routed to the new lined CCR pond. A flow diagram of the new configuration is shown in Figure 5. Modifications of the existing system are shown in red.

Figure 5: Flow Diagram for New Lined CCR Pond



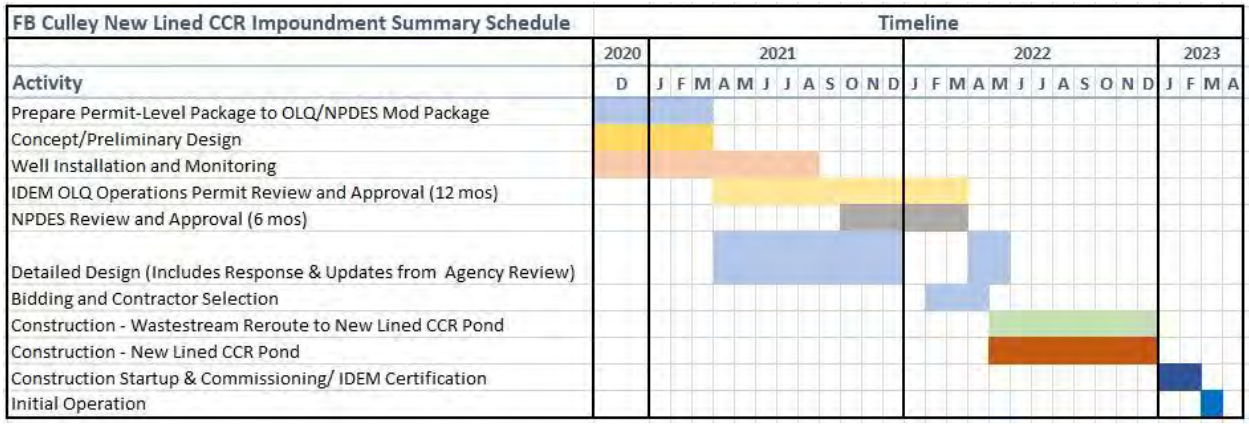
Rerouting of CCR flows from the East Ash Pond requires the design and installation of new transfer lines to the new lined CCR pond and lines from the New Lined CCR pond to the Contact Storm Water Pond, then discharge through permitted Internal Outfall 101 and ultimately through NPDES permitted Outfall 001. The new lined CCR Pond would flow by gravity through the new Contact Stormwater Pond and ultimately discharge through Outfall 001. The existing FGD wastewater treatment system at the East Ash Pond will be replaced or relocated to the new lined CCR Pond area. New electrical and controls infrastructure will be installed at the new lined CCR Pond to support the new equipment and Wastewater Treatment System in this area. To implement this alternative, the following steps would be performed:

- Groundwater Monitoring – Design, Installation, Data Collection and Evaluation
- Conceptual Design
- Preliminary Design
- Permitting - IDEM OLQ Operations Permit and NPDES Major Modification
- Detailed Design
- Engineered Equipment Procurement
  - Pumps
  - Power Distribution Center (PDC), Transformers
  - Distributed Control System (DCS) Integration
- Structural, Mechanical, Electrical and Controls Contractor Bid, Selection and Award
- Structural, Mechanical, Electrical and Controls Construction
  - Reroute of Unit 2 Bottom Ash and FGD wastewater lines to new pond area
  - Installation of new FGD wastewater treatment system
  - Discharge pumping system and ancillary components

    - Electrical, controls and balance of plant (BOP) scope
- Civil Earthworks Contractor Bid, Selection, and Award
- Procurement
- Civil & Earthworks Construction
    - Reroute of clean stormwater conveyance in pond footprint
    - Construct pond embankment
    - Subgrade Preparation
    - Construct composite CCR Pond Liner
    - Construct lines and/or pump stations for flow redirection (concurrently with other features)
    - Provide flow equalization connection between new lined CCR Pond and Contact Stormwater Pond
- Start-up and Commissioning
- Initial Operation

The approximate durations of key activities are summarized in **Figure 6**.

Figure 6. Estimated Simplified Schedule for New CCR Pond in *Excavation Area*



The expected timeframe to complete these efforts is 27 months from December 1, 2020, with an estimated completion date of March 1, 2023. IDEM requires that an operations permit be issued for operation of a new CCR surface impoundment. Based on recent IDEM discussions, they indicated that a 12-month period is the current timeframe for review and issuance of this approval. As such, the schedule includes a 12-month duration for this permit review. Detailed design, equipment procurement and construction not related to civil earthwork for the new lined CCR Pond will be performed concurrent with the OLQ review. Again, Figure 6 represents a simplification of key activities in the overall timeline. For a detailed critical path schedule, schedule see **Appendix C**.

Alternative 3 – Construction of a New On-site CCR Rule-Compliant Pond – Area to North of East Ash Pond

Based on site property availability, construction of a new lined CCR pond in the area north of the East Ash Pond was also considered as part of the options analysis. The potential area north of the East Ash Pond is not currently utilized for plant operations and could be a potential location for such a pond. **Figure 7** below demonstrates the proposed location of the new pond.

The potential area of the new lined CCR pond is not ideal and has steep hill slopes that would require significant earthwork to construct a new pond. The area of the new pond is at an elevation significantly higher than the current East Ash Pond, which would make the re-routing of flows more difficult and would include additional pumps and replacement of existing infrastructure. A proposed pond in this area would also encroach on existing drainage features and potentially require Section 401/404 permitting. Based on recent experience, a Section 401/404 permit can take on the order of one year to obtain. Similar to Alternative 2, this proposed pond would also require an operations permit issued by IDEM OLQ. Considering these complications, a new pond in this proposed area would likely require 36 months to complete, significantly longer than Alternative 2. Based on these considerations, this option is not considered the fastest technically feasible alternative and has been eliminated from consideration.

Figure 7. Potential Location of New On-site CCR Rule-Compliant Pond

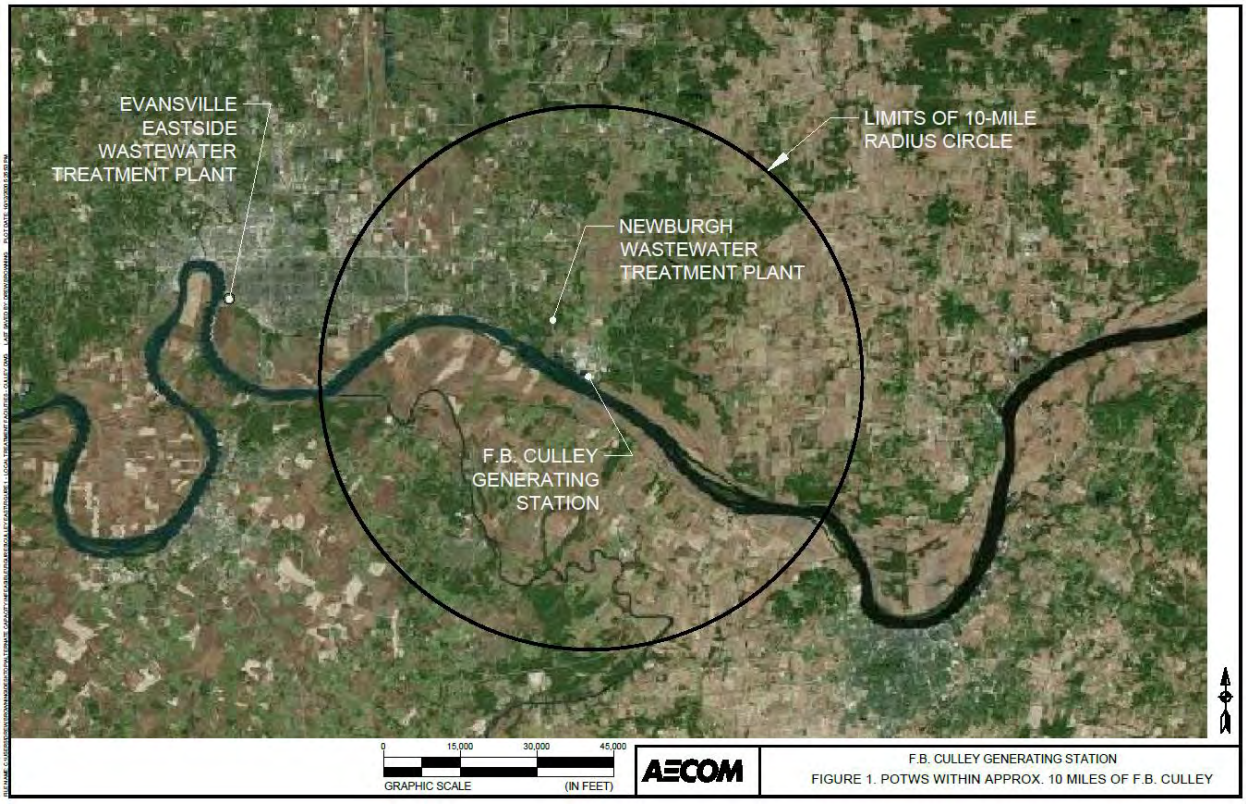
5.1.2 Off-site Alternative Capacity

As required by Part A, off-site options for alternative capacity were also considered. Alternative 4 (described below) was developed to address a potential off-site management option.

Alternative 4 –Alternative Capacity Off-site

Alternatives for off-site treatment of the FGD wastewater flow discharged to the East Ash Pond were evaluated. For this alternative, the FGD wastewater would be transported to either a publicly owned treatment works (POTW) or a private facility capable of managing the wastestream. A 10-mile radius from F.B. Culley was surveyed for POTWs or private facilities that may be capable of treating the waste flows. This radius is shown below, overlaid on the area surrounding the station. The POTW of Newburgh, Indiana, is located approximately within this radius, as shown in **Figure 8.**

Figure 8. POTWs Within 10 Miles of F.B. Culley Generating Station



As shown, the Newburgh POTW is the only wastewater treatment facility (WWTF) located within a 10-mile radius. Evansville Eastside POTW is located just outside this radius. The Regional Water Resource Agency's closest plant, Max Rhoads WWTF (serving Owensboro and Daviess County, Kentucky) was also considered as its straight-line distance from the plant is approximately 12 miles. However, due to the road configuration and limited bridges available across the Ohio River, the actual travel distance to the plant is approximately 25 miles one way, and as such, only the Newburgh POTW and Evansville Eastside POTW were examined in detail.

As the closest POTW, a pipeline to convey the FGD wastewater stream to the Newburgh POTW was considered. The straight-line distance for such a pipeline would be approximately 2.2 miles. For transportation via pipeline, this alternative would require several key items to be completed rapidly to be successful:

- Selection of pipeline route would require the completion of any environmental studies and environmental permitting from regulatory agencies.
- Application for any required federal and/or state permitting required, and timely receipt of approval.
- Acquisition of easements for pipeline right of-way.
- Design of pipeline and any necessary pumping stations.
- Construction of pipeline and pumping stations.
- Final testing.

Given the length of pipeline required and the significant regulatory and design obstacles, construction of a pipeline to a POTW is not the fastest technically feasible alternative. This alternative would require longer than 36 months to complete the route evaluation, permitting, design, property access rights, and construction of such a pipeline.

This timeline would exceed that of Alternative 2 and would not represent the fastest technically feasible alternative. This option would also come with significant schedule risks in the event property access could not be obtained

Transportation of FGD wastewater flows via truck was also considered. The FGD wastewater flow accounts for 95,000 GPD that would need to be transported to an off-site facility for treatment. Assuming a truck capacity of 5,000 gallons, 19 truckloads would be needed daily to transfer FGD wastewater to the off-site WWTF. Although truck transport of this quantity of wastewater is feasible, the nearby Newburgh POTW facility cannot accept truck delivery of wastewater. Further, several of the facilities contacted place limitations on the total suspended solids (TSS) in the wastestreams they can accept. The city of Evansville limits raw wastestreams to 2,114 milligrams/Liter (mg/L), which is substantially lower than the wastestreams currently discharged to the East Ash Pond. Pretreatment to reduce the TSS is required before treatment can be considered by any of the POTWs contacted. In addition to limitations on TSS, POTWs are not equipped to treat the constituents in FGD wastewater.

Many, if not all, of their processes are incompatible with treatment of the CCR wastewater flows from F.B. Culley. The existing Newburgh POTW consists of an activated sludge system with eight (8) sequencing batch reactors followed by ultraviolet disinfection. The system is designed to remove TSS, biological oxygen demand (BOD), and pathogens prior to discharging to the Ohio River. Additional treatment steps would likely be required to remove dissolved metals to below applicable categorical and local standards.

The requirement to pretreat FGD flows removes any benefit of managing this wastestream off-site. In addition, this option would not address the Unit 2 bottom ash wastestream as significant solids removal (in settling tanks for similar facilities) would be required prior to transport of the material. Given the additional infrastructure required for off-site management and treatment of the FGD wastewater flows, completion of this project is not considered to be technically feasible prior to October 15, 2023 and does not represent the fastest technically feasible alternative.

5.1.3 On-Site Wastewater Treatment Facility Alternatives

The FGD wastewater stream must meet the effluent limitations as defined by the current NPDES permit for F.B. Culley. The F.B. Culley NPDES permit contains a reopening clause that allows the facility to request a compliance date that is no later than December 31, 2023 for the Unit 3 FGD wastestream if unit retirement or ZLD technology is pursued. In 2017, various options to comply with the NPDES permit were evaluated including ZLD and advanced wastewater treatment. A ZLD technology that would eliminate the FGD wastewater stream was selected. The selection of the ZLD technology was included in a filing to the IURC seeking approval for the capital expenditure. The Order granting approval was issued April 24, 2019. The ZLD technology selected is detailed in Alternative 8.

Alternative 5 – Temporary Wastewater Treatment Facility (WWTF)

A temporary WWTF to treat the FGD wastewater stream was also considered. To replace the operational functions of the East Ash Pond, the temporary WWTF requires a significant amount of storage capacity and the capability to remove and dewater the suspended solids in these waste streams. The WWTF consists of the following primary components:

- Equalization Storage Tanks - to receive and store the influent flows.
- Primary Dewatering Clarifier/Thickeners - to remove suspended solids from the liquid.
- Filter Feed Storage Tanks – to receive the clarifier/thickener underflow and store until fed to the secondary dewatering filter presses.
- Secondary Dewatering Filter Presses - to remove liquid from the solids so that they can be disposed in a landfill.
- Treated Water Storage Tanks - to store the water that is returned to the system or discharged.

Equalization tanks balance the flow to the downstream clarifiers and blend the wastestreams to reduce fluctuations in temperature and composition. The equalization tanks are sized for 24 hours of wastestream production to

address upset conditions in the WWTF and influent peak flow events such as stormwater runoff. The 0.233 MGD of CCR flow requires 250,000 gallons of capacity in the equalization tanks. The system would have 2 tanks, each 30' in diameter and 30' in height with mixers to prevent the solids from settling.

From the equalization tanks, the untreated wastestreams will be transferred to one of two clarifier/thickeners. Clarifier/thickeners is a large quiescent circular tank that removes the suspended solids by settlement. For these streams, each clarifier is approximately 110' diameter by 15' high. The large clarifier/thickeners volume is required to provide the 10 days of residence time required for the wastewater treatment reagents added to remove the mercury from the FGD wastewater. A coagulant and polymer are also added to the feed stream to promote settling and produce a low suspended solids stream. A rotating rake assembly moves the settled solids to the center of the clarifier/thickeners where they are discharged to the filter feed storage tanks. The overflow from the clarifier/thickeners is collected in a sump and pumped to one of the treated water storage tanks. Any water discharged must meet the TSS requirements and mercury limitations of the NPDES permit.

The treated water tanks would store the water for re-use by the system. Return water pumps would send water back to the system for re-use for bottom ash transport, fly ash transport and FGD system make-up. The treated water tanks would be sized for 250,000 gallons of capacity in 2 tanks. Each tank would be approximately 30' in diameter by 30' height and an agitator would not be required.

The filter press is a batch operation. Because solids must be purged from the clarifier/thickeners on a continuous basis, filter feed storage tanks are required. Filter press performance is highly dependent on the characteristics of the solids. Fly ash and FGD solids are among the more difficult to dewater and a filter press cycle time of 3 to 8 hours is expected for this material. To accommodate batch operation, 150,000 gallons of filter feed storage capacity is required. Due to the higher solids content, 2 tanks of 75,000 gallons, approximately 24' x 24' each, would be installed.

The filter press units would be fed from the filter feed tank with high-pressure diaphragm pumps. The fill cycle for a filter press varies dependent on the characteristics of the material. Based on the throughput, 2 or more filter press units are required. Dewatered solids would drop from the filter press units to the roll away bin and be taken to a landfill. The filtrate would be collected and returned to the clarifier/thickeners. Solids that are disposed in the landfill must meet the requirements for free liquids.

The project scope for this WWTF includes field-erected tanks, engineered equipment, structural steel, buildings, piping, electrical, and controls. A significant amount of engineering design is required including:

- Major Engineered Equipment – The system included the following engineered equipment: pumps, agitators, clarifiers, filter presses, power distribution systems, and distributed control systems. The design and manufacturing duration for this equipment ranges from 6 – 12 months after receipt of order.

- Foundations – The WWTF has 6 tanks ranging in size from 75,000 to 250,000 gallons. Each tank will require deep foundations, typically 30' to 60' piles, a mat and containment walls. The 2 clarifier/thickeners, each 110' in diameter also require deep foundations. The filter press unit must be elevated to discharge to the bins these structural support members and enclosure will also require deep foundations.

- Field Erected Tanks – The tanks would all be knockdown field erected. Panel sections would be fabricated, then assembled in the field.

- Electrical and Controls - The new WWTF will require a new electrical service for the pumps, agitators, clarifiers, filter press, freeze protection, heating, ventilation and lighting. New instrumentation and controls are required to operate this system.

In addition to the WWTF, the existing wastestreams must be re-directed from the East Ash Pond to the new facility. New pipe runs are required, and the existing systems will require upgrade and modification to transport these wastestreams to the new WWTF.

The following table summarizes the fastest schedule for implementation of a WWTF to treat the wastestream flows to the East Ash Pond.

Table 3. Temporary Wastewater Treatment Facility Implementation Schedule

Activity	Estimated Duration
Conceptual Design and Investigations	3 months
Major Equipment Vendor Selection and Award	2 months
Detailed Design	12 months
Construction Contractor Selection and Award	2 months
Construction	18 months
Start-up and Commissioning	3 months
Initial Operation	2 months
Total	**42 months**

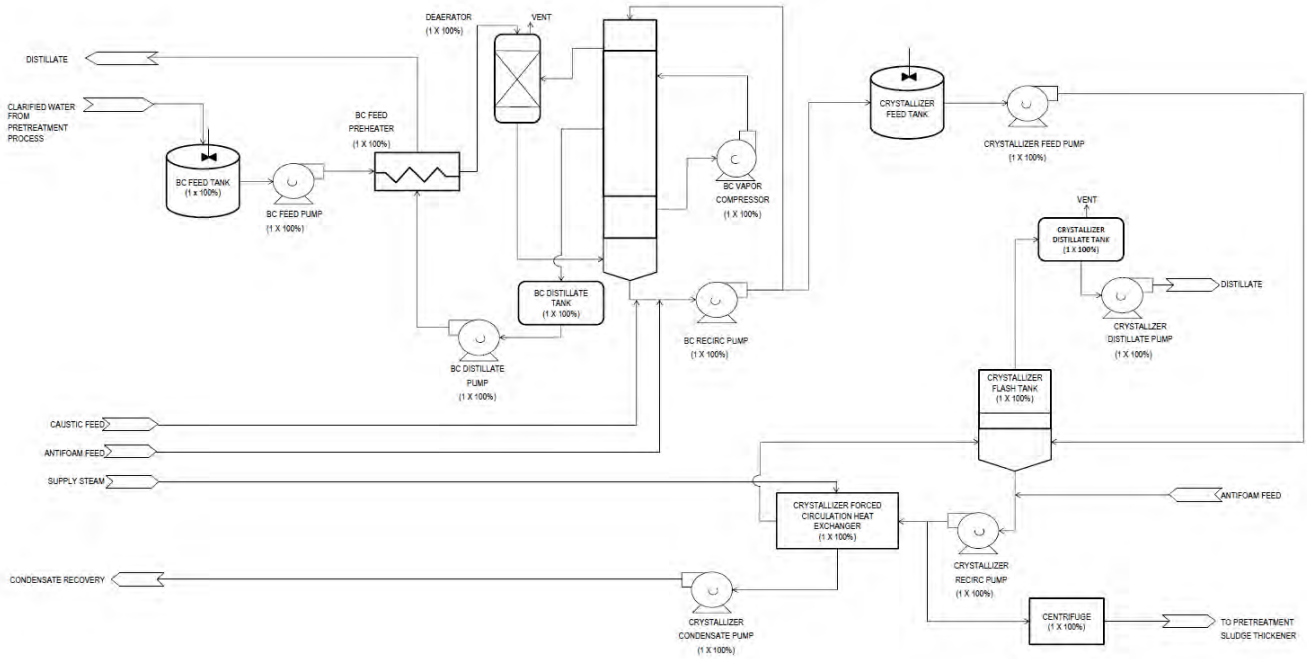
The fastest feasible duration to construct a WWTF is 42 months from December 1, 2020. The estimated completion for the system is June 1, 2024 and significantly exceeds the timeframe of the fastest technically feasible alternative.

Alternative 6 – Brine Concentrator

A brine concentrator / crystallizer is a ZLD technology. The system is a thermal process that concentrates dissolved species in a brine sludge that is then solidified in the crystallizer unit. Crystallized solids (salts) can then be disposed in a landfill. For an FGD wastewater application, pretreatment steps are required to 'soften' the wastewater prior to thermal treatment to reduce scaling and a reduction in throughput. The softened wastewater is then thermally treated in the brine concentrator or encapsulated with fly ash and lime. Evaporated water, now free of dissolved solids, is collected and returned to the plant as makeup water.

The materials of construction for the brine concentrator and crystallizer must be resistant to corrosion due to the high concentrations of chloride and elevated temperatures associated with the process. As a result, fabrication of the equipment has a long duration and requires over 12 months to procure. Brine concentrator and crystallizer for the FGD wastewater was not the selected option due to reliability issues in comparison with other ZLD options. Total project duration to design, procure, and install a brine concentrator is 36 to 42 months. A schematic of the brine concentration and crystallization steps was prepared by Black and Veatch and is presented as **Figure 9**. While potentially feasible, this option was not selected as the preferred option could be implemented in a shorter timeframe. In addition, this option is limited in that it would not address Unit 2 bottom ash flows.

Figure 9: Brine Concentrator / Crystallizer Schematic



Alternative 7 – Membrane Separation

Membrane separation is also a ZLD technology for treating FGD wastewater. This technology is typically used in conjunction with encapsulation to produce a waste product that can be landfilled. In a reverse osmosis system, a pump is used to convey a high-pressure stream of FGD wastewater across a polymeric membrane. The FGD wastewater salts are concentrated on one side of the membrane while a clean permeate (product stream) stream is discharged from the opposite side. The permeate can be returned to the FGD system as makeup water (ZLD) or discharged. The concentrated brine stream can be blended with fly ash and/or lime and landfilled. Membrane systems require pre-treatment of the wastewater to remove suspended solids and reduce scaling potential. Upstream pre-treatment typically includes clarification, sand filters, cartridge filters, anti-scalant additives, anti-microbial additives, and pH adjustment.

There is limited experience within the utility industry applying membrane separation for the treatment of FGD wastewater. This is an emerging technology and is not expected to be ready for commercial application for several more years. In consideration of the uncertainties regarding long term performance and reliability, and extended duration for project implementation, membrane technology is a technically infeasible alternative. In addition, this option is also limited in that it would not address Unit 2 bottom ash wastestream.

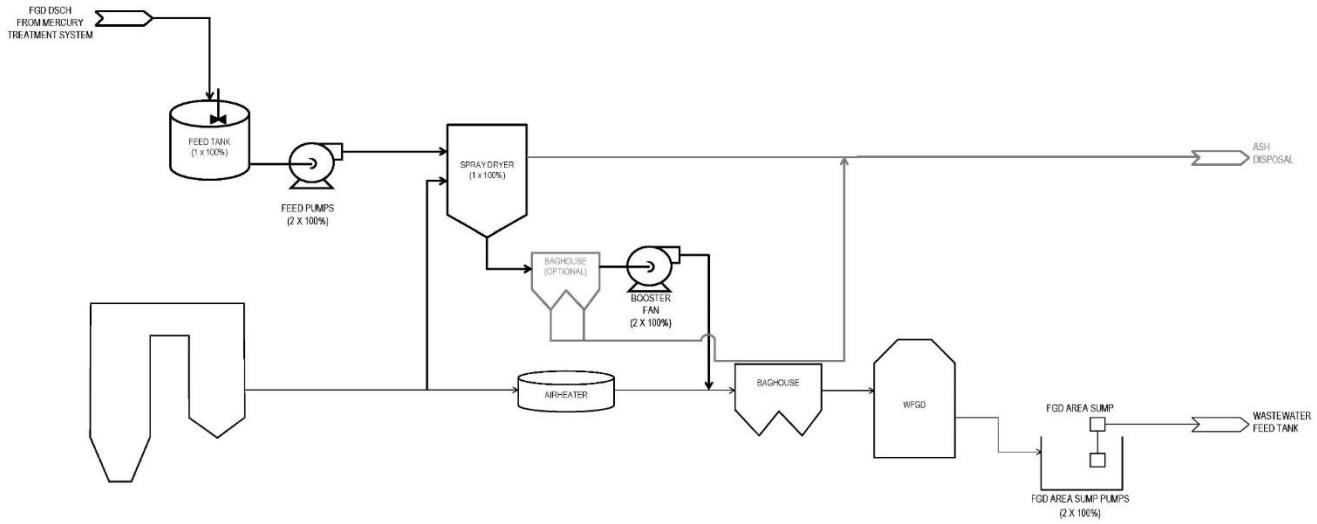
Alternative 8 – Wastewater Spray Dryer

A wastewater spray dryer evaporator (SDE) system uses a slip stream of hot flue gas to evaporate a wastewater upstream of a particulate collection device. Solids and salts in the wastewater are atomized and dried in the spray dryer vessel. The flue gas can either be returned to bulk flue gas stream where the solids are removed with the fly ash or routed to a separate particulate collector prior to being returned with the bulk flue gas. A preliminary process flow diagram of a wastewater spray dryer system is provided in **Figure 10**.

While waste spray dryer technology has only been recently applied to FGD wastewater, it is based on established technology in a similar application. An estimated duration of 33 months is required to design, procure and install a wastewater spray dryer system. While this alternative continues to be pursued for continued operation of Unit 3 beyond the NPDES compliance date of December 31, 2023, the timetable for completion of this option exceeds

that of Alternative 2 and is not considered the fastest technically feasible alternative. It also has the limitation of not addressing Unit 2 bottom ash flows.

Figure 10: SDE Process Flow Diagram



5.1.4 Alternative Selected and Analysis of the Site and any Site-Specific Conditions that Led to the Alternative Selected (40 CFR § 257.103(f)(1)(iv)(A)(1)(i))

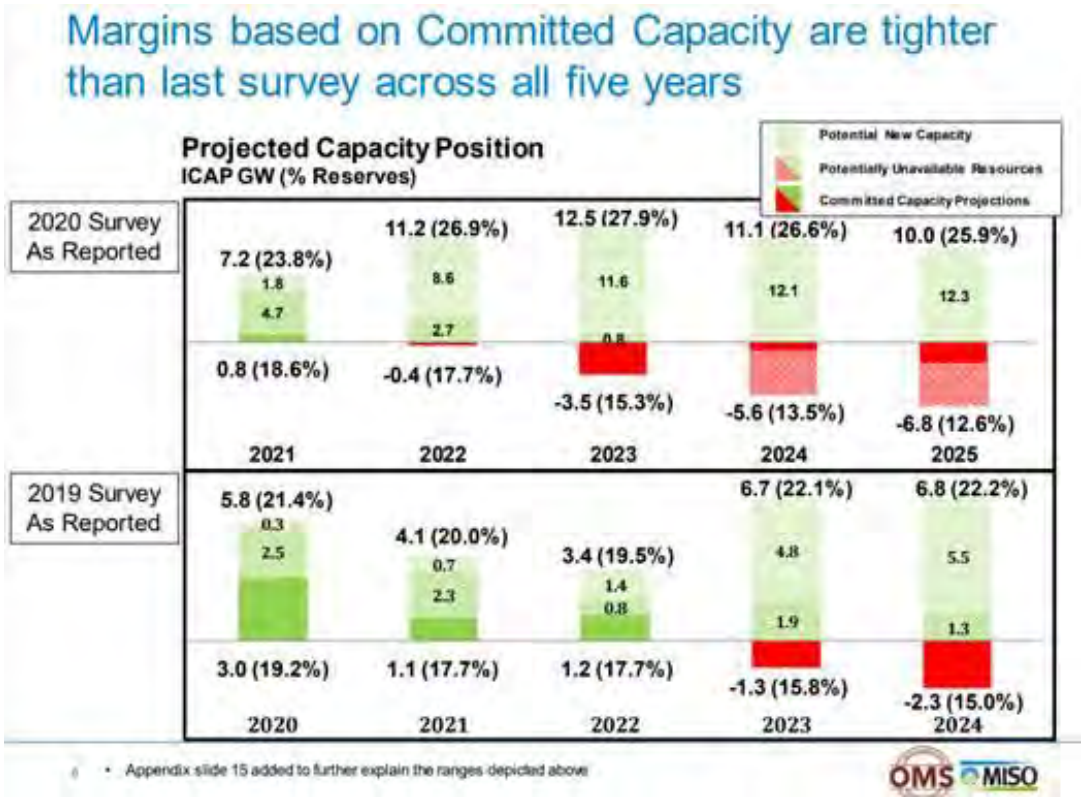
Alternative 2 (new lined CCR Pond) has been selected based on the following site-specific and other considerations:

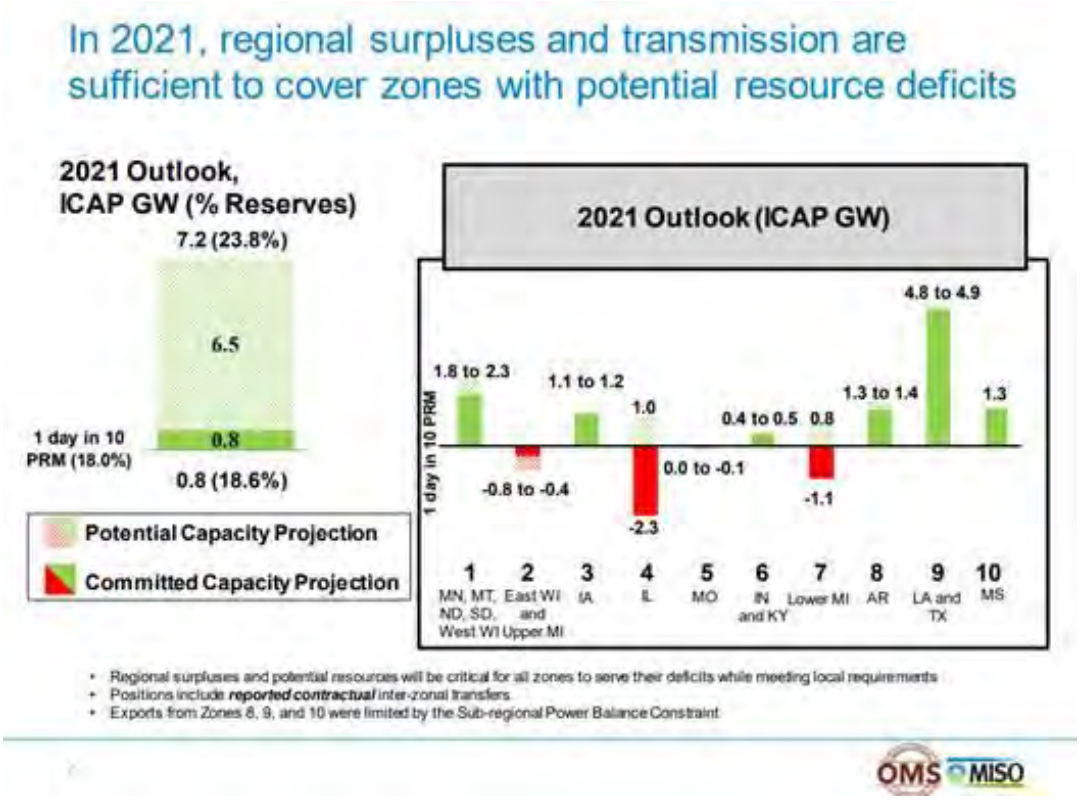
- Alternative 2 represents the “fastest technically feasible timeline” for addressing remaining flows to the East Ash Pond,
- The area selected for the new lined CCR Pond is well known (geotechnical characteristics, groundwater levels, etc.) and is ideal for construction of a new pond system,
- Alternative 2 involves reroute of flows, but does not involve significant mechanical or other treatment-related systems with longer lead times and startup/operational challenges, and
- Alternative 2 is well understood and defined, and has a high level of construction schedule certainty.

5.1.5 Adverse Impact on Plant Operation if the East Ash Pond Were No Longer Available (40 CFR § 257.103(f)(1)(iv)(A)(1)(ii))

Given the lack of current alternative capacity, continued operation of Units 2 and 3 at F.B. Culley is wholly dependent on the continued operation of the East Ash Pond until alternative capacity can be obtained for all flows managed by the East Ash Pond under Alternative 2 (March 1, 2023). If the CCR and non-CCR flows to the East Ash Pond were to cease on April 11, 2021, without alternative capacity available, Units 2 and 3 will not be able to continue operation.

F.B. Culley Units 2 and 3 have a combined capacity of 387 MW and currently comprise 27 percent of SIGECO’s generating units. F.B. Culley Units 2 and 3 are an essential part of the generation capacity within the fleet and the region. The results of the 2020 MISO Organization of MISO states survey projects a slight capacity surplus for zone 6 in 2021 and a potential shortfall in 2025. The survey shows that the MISO system in its entirety could experience a shortfall as early as 2022.





The source for the charts shown above:
https://cdn.misoenergy.org/20200708%20RASC%20Item%2004a%202021%20OMS-MISO%20Survey456786.pdf

5.1.6 Explanation and Justification for the Amount of Time being Requested and How it is the Fastest Technically Feasible Time to Complete the Development of Alternative Capacity

Based on this evaluation, the fastest technically feasible option for obtaining alternative capacity is a new lined CCR Pond in the vicinity of the new lined Contact Stormwater Pond (Alternative 2). This alternative supplements current plant activities to reduce flows to the East Ash Pond (i.e., dry bottom ash conversion of Unit 3 and management of non-CCR flows in the new lined Contact Stormwater Pond). With construction of a new lined CCR Pond, all flows to the East Ash Pond can cease on or before March 1, 2023. In addition, this option provides for significant flexibility in the event of operational and/or future generation changes. While ZLD technology consisting of a SDE system has been selected and continues to be pursued for addressing NPDES and Effluent Limitation Guideline (ELG) regulatory considerations relating to Unit 3 FGD flows, this project (if completed) would result in a cease flow date after Alternative 2 and is not considered the "fastest technically feasible timeline" for ceasing flows to the East Ash Pond. The selected alternative (Alternative 2) for management of non-CCR and future closure-related flows represents the fastest technically feasible time to obtain alternative capacity for these flows.

5.2 Detailed Schedule and Narrative Discussion (40 CFR § 257.103(f)(1)(iv)(A)(2) and (3))

The provisions of 40 CFR § 257.103(f)(1)(iv)(A)(2) and (3) require that a detailed schedule be provided illustrating the fastest technically feasible time to complete the measures necessary for alternative capacity to be available including a visual timeline representation. The visual timeline must clearly show the following:

- How each phase and the steps within that phase interact with or are dependent on each other and the other phases (40 CFR §257.103(f)(1)(iv)(A)(2)(i)),
- Steps and phases that can be completed concurrently (40 CFR §257.103(f)(1)(iv)(A)(2)(ii)),
- Total time needed to obtain the alternative capacity and how long each phase and step within each phase will take (40 CFR §257.103(f)(1)(iv)(A)(2)(iii)), and
- At a minimum, the following phases: engineering and design, contractor selection, equipment fabrication and delivery, construction and start-up and implementation (40 CFR §257.103(f)(1)(iv)(A)(2)(iv)).

In addition, 40 CFR §257.103(f)(1)(iv)(A)(3) requires a narrative discussion of the schedule and visual timeline representation which must discuss all of the following:

- Why the length of time for each phase and step is needed and a discussion of the tasks that occur during the specific step (40 CFR §257.103(f)(1)(iv)(A)(3)(i)),
- Why each phase and step shown on the chart must happen in the order it is occurring (40 CFR §257.103(f)(1)(iv)(A)(3)(ii)),
- The task that occur during each of the steps within the phase (40 CFR §257.103(f)(1)(iv)(A)(3)(iii)), and
- Anticipated worker schedules ((40 CFR §257.103(f)(1)(iv)(A)(3)(iv)).

These items are provided and discussed in the following sections.

5.2.1 Regulatory and Other Considerations Associated with Overall Project Schedule

The scenario at F.B. Culley involves a series of interrelated regulatory and technical milestones. In order to address the requirements of this section, two detailed schedule representations have been provided. The first, provided in **Appendix B**, provides a representation of the overall schedule for F.B. Culley, which includes sections for the regulatory process to select future generation technology, CCR-related activities, and alternative pond capacity development activities. This schedule is intended to represent the overall scenario at F.B. Culley and illustrates the interrelationships of the various activities.

5.2.2 Design and Installation Schedule

The cessation of CCR and non-CCR flows to the East Ash Pond requires alternative capacity to replace these functions. Based on current construction schedules, the East Ash Pond will be required to manage non-CCR flows until the new lined Contact Stormwater Pond is complete and operational (by end of 2020) and non-CCR flows can be re-routed (by July 1, 2021 under current IDEM OLQ commitments). Unit 3 Bottom Ash flow will be eliminated no later than December 31, 2020 (NPDES requirement). FGD wastewater and Unit 2 bottom ash streams will be redirected to a new lined CCR Pond (Alternative) which will be constructed adjacent to the new Contact Stormwater Pond. Based on the implementation schedules discussed within this document, this new lined CCR pond will be complete and operational on or before March 1, 2023.

Essentially, the approach selected to obtain alternative capacity has the following three subprojects:

- **Unit 3 Boiler Bottom Ash Handling System Wet to Dry Conversion – Submerged Chain Conveyor**

Unit 3 Bottom Ash flow will be eliminated from the East Ash Pond by the end of November, which is before the NPDES permit required date of December 31, 2020, when the new SCC system is completed and functional.

- **Closure of West Ash Pond / New Lined Contact Stormwater Pond and Re-Routing of Non-CCR Waste Piping**

Based on current construction schedules, the East Ash Pond will be required to manage non-CCR flows until the contact stormwater pond is complete and operational, which is on schedule to be completed by the end of 2020. At that time, physical construction work to re-route non-CCR flows from the East Ash Pond to the new contact stormwater pond can begin, with a scheduled completion date of no later than by July 1, 2021. Detailed design for re-routing these flows began in July of 2020 and is expected to last 6 months in duration. Following completion of design activities, a 3-month contractor bidding and selection period will occur, with an expected contract award date by end of February 2021. Construction is expected to take 4 months in duration, which includes 2 weeks for start-up and commissioning followed by initial operation of 2 weeks prior to cessation of flow for non-CCR streams to the East Ash Pond by July 1, 2021. A schedule for key milestone activities is found in **Table 4**.

Table 4: Milestone Activities for Re-routing Non-CCR Flows

MILESTONE ACTIVITY	DATE
Design Team Site Visit	6/24/2020
Receipt of 60% Design Documents	10/14/2020
Receipt of 90% Design Documents / Issue Bid Package	12/9/2020
Award Construction Project	2/28/2021
Project Completion/ Cease Flow of Non-CCR Streams to East Ash Pond	7/1/2021

- **New Lined CCR Pond and Re-Routing of CCR Piping**

The selected alternative (Alternative 2) will require 27 months for conceptual and preliminary design, permitting, detailed design, vendor and contractor selection, equipment fabrication, construction and start-up and commissioning. In consideration of the overall process leading to cessation of flows (both CCR and non-CCR) to the East Ash Pond, this effort is considered critical path. Below is a detailed discussion of the anticipated schedule for implementation.

The project schedule for the selected alternative can be broken down to the following segments:

a. Conceptual and Preliminary Design
b. Permitting
c. Detailed Design
d. Equipment Procurement and Manufacture
e. Construction Bid and Award
f. Construction
g. Construction Certification / Start-up and Commissioning
h. Initial Operation

5.2.2.1 Conceptual and Preliminary Design

Work on this phase for alternative capacity will initiate in December 2020 with project kick-off and the beginning-of-project definition and preliminary design. This phase will include various field investigations and infrastructure and information gathering to support the preliminary design and operating permit application. Groundwater monitoring wells will be installed to address CCR Rule requirements (as needed) and establish the groundwater water levels to provide a minimum elevation for the base of the future CCR Pond liner system. Groundwater monitoring data from existing wells will also be considered in order to provide a complete assessment in the fastest feasible timeframe. Key deliverables from this phase include:

a. Design Basis
b. Plant Water Balances and Process Flow Diagrams
c. Overall Site Plan
d. Install Groundwater Monitoring Wells
e. Preliminary Pond Design Drawings and Specifications
f. Permit Application Package
g. Permit Applications (i.e. IDEM OLQ Submittal and NPDES Major Modification)
h. Cost Estimate
i. Detailed Project Schedule

The new lined CCR Pond will be sized based on the expected flows. An ideal candidate location has been identified in the area to the north of the new lined Contact Stormwater Pond. A key objective of the preliminary design phase is to develop the permit package for submittal to IDEM OLQ. This task along with the installation of groundwater monitoring wells are on the critical path.

Other objectives of this phase include detailed information of the CCR streams that discharge to the East Ash Pond. This includes verification of the flowrates, composition, temperature, pressure and operating requirements. Activities to gather this information may include flow measurements, sampling and analysis, review of plant operating data and the collection of design information. Once all the streams have been defined and characterized, a conceptual design will be developed to redirect the flows to the new lined CCR pond. This may include the modification of existing plant facilities, re-grading to redirect stormwater and new facilities to transport the flows to the new lined CCR Pond. Four months are planned for the conceptual design phase.

The scope for the preliminary design phase will be refined based on the results of the conceptual design. Potential design issues and the information needed will be established. Development of the preliminary design will follow the conceptual design. This phase is expected to be completed in 4 months.

5.2.2.2 Permitting

A number of permitting requirements are associated with the selected alternative for alternative capacity. The two primary required permits are summarized below:

1. CCR Surface Impoundment Operations Permit from IDEM OLQ – Indiana is very involved in the surface impoundment operations approval and closure approval process as surface impoundments are regulated

by the state as land disposal units and Indiana has adopted reference to the Federal CCR Rule within their state regulations (329 IAC 10). While approval is not required for construction of a CCR surface impoundment, approval by IDEM OLQ is required for operation of a CCR surface impoundment. This process consists of submission of design materials, flows, and associated calculations and analyses. SIGECO representatives recently contacted IDEM to discuss the review time for this CCR surface impoundment operations approval, and IDEM indicated that 365 days (from submission) is the typical timeframe for approval. This review period has been factored into project schedules and will involve preparation of a permit-level design package for IDEM review and approval early in the design process (first four months), and detailed design will be continued during IDEM review of this package. During the review process, the permit-level design package will need to be supplemented with data demonstrating compliance with the aquifer separation criteria of 40 CFR 257.60.

- While the CCR Surface Impoundments Operations Permitting process is occurring, SIGECO will also be working with IDEM to obtain approval for the construction of the pond in this specific location, in accordance with requirement A2 of the "Approval of Closure/Post-Closure Plan F.B. Culley West Ash Pond" issued by IDEM, dated December 20, 2019. Requirement A2 states, "The owner or operator must request approval from IDEM before modifying the approved closure/post-closure requirements and procedures."

2. NPDES Major Modification – In order to address the proposed CCR flow treatment changes, a Major Modification of F.B. Culley's NPDES permit will be required. Based on recent IDEM experience and discussions with IDEM, 6 months is required from package submission to approval. Again, this has been factored into the schedule and this activity occurs in parallel with other activities (such as detailed design and OLQ review of the CCR surface impoundment application). It should be noted that there is schedule float associated with this permit approval process, and it can lag in schedule by approximately 6 months if needed without affecting the overall project timeline.

There will be a number of other approvals required such as permit coverage for Stormwater Associated with Construction Activities (Rule 5 in Indiana). However, these are typically shorter lead time permits and are not near the critical path.

Finally, it should be noted that the permitting timelines assume a Section 401/404 permit will not be required. This is a reasonable assumption given that new fill was just placed in the proposed CCR Pond area and it appears no stream crossings or tree clearing will be required for the construction activities of the CCR Pond or associated piping systems.

5.2.2.3 Detailed Design

The detailed design phase will commence following the conceptual and preliminary design and will occur in parallel to IDEM permit reviews. The key objective of the detailed design phase is to develop a design package and specifications for the equipment procurement and construction packages. Work from the conceptual and preliminary design will be used to develop drawings and specifications. Key deliverables from this phase include:

a) Final Pond Site Plan, Sections and Details Drawings
b) Final Pond Grading Plans and Calculations (geotechnical, stormwater management, pond capacity, etc.)
c) Liner and Earthwork Specifications
d) Piping and Instrument Diagrams (P&IDs)
e) General Arrangements (GA's)
f) Pipe Routing and Lists
g) Electrical One Lines, Circuit Drawings, Cable Routing Drawings, Schedules
h) Control System Logic, Input Output Lists, Connection Diagrams
i) Construction and Equipment Specifications

Detailed design will be executed concurrently with on-going groundwater monitoring activities and permitting support. The pond design will not be finalized until all required design approvals have been received and permitting

authorities have completed their reviews. Design tasks associated with the redirected flows from the East Pond include hydraulic calculations, pipe support design, electrical and control cable routing and termination diagrams, electrical load studies and control logic development. It may be necessary to proceed with the procurement of specific engineered equipment to achieve schedule milestones. This information may include electrical and controls circuits diagrams and equipment interface connections. A total of 10 months is planned for detailed engineering and design. During this phase, Issue for Bid (IFB) packages will be completed. Issue for Construction (IFC) packages will be developed following contractor award and completion of review/approval by the permitting authorities.

5.2.2.4 Equipment Procurement and Manufacture

Mechanical Engineered procurements are expected to include pumps or pump upgrades. A duration of 1 month is expected to receive vendor bids with 2 months to evaluate and award each package. Based on previously solicited vendor bids for similar equipment pumps are expected to have a 6-month lead time after receipt of order (ARO) for manufacturing and delivery, resulting in a total duration of 9 months for mechanical procurements.

Electrical procurements are expected to include transformers, motor control centers (MCC), power distribution centers (PDCs), and distributed control system components. As with the mechanical procurements, a duration of 1 month is expected to receive vendor bids and a 2-month period for evaluation and vendor award. The long lead items associated with electrical procurements have been identified as the PDCs with an expected lead time of 9 months ARO for manufacturing and delivery, resulting in a total duration of 12 months for mechanical procurements.

Mechanical and Electrical procurements occur in parallel for a total procurement cycle of 12 months. These activities follow completion of the mechanical detailed design and runs in parallel with completion of the electrical detailed design. The manufacturing and delivery of these components will occur in parallel with construction of the new pond. Other procurements are piping, structural steel, pond liner, valves and instrumentation. These items have been identified to have a short lead time and will be purchased by the construction contractor. They do not impact the overall project schedule and will occur in parallel with the mechanical and electrical procurements.

5.2.2.5 Contractor Bid, Selection and Award

In this phase, a Request for Proposal (RFP) will be issued to contractors to construct the system. The project scope may be bid and awarded in 2 separate packages:

- Package 1 - mechanical, structural, electrical and control scope that is not associated with the pond
- Package 2 - civil earthworks associated with the new CCR Pond

The decision to award the construction in 1 or 2 packages will be based on achieving the shortest duration for construction.

The bid, selection, and award phase is expected to take 3 months from issuance of the RFP. This includes 1.5 months for the bidders to prepare proposals and 1.5 months for evaluation and contract negotiations. Evaluation of the proposals includes a review of the means and methods of construction proposed by the bidders and any alternates that may improve the design or reduce the project schedule. The duration of the evaluation period is dependent on the quality of the proposals received, responsiveness of the bidders to questions, and complexity of the alternates considered. These activities occur concurrently with completion of detailed design and equipment fabrication and delivery.

5.2.2.6 Construction and Start-Up

The candidate location for the new lined CCR Pond is the CbR *Excavation Area* of the West Ash Pond closure (area currently complete). The CCR materials from the former West Ash Pond footprint have been completely removed and verified, and structural fill has been placed over the excavation grades to create a network of stormwater conveyance channels that manage clean (non-contact) stormwater flows from contributing drainage

areas across the plant property. The new pond will meet the requirements for a composite liner system under the Federal CCR Rule (40 CFR § 257.72) as well as the location restrictions of 40 CFR § 257.60-64. The successful completion of groundwater monitoring and completion of review by the regulatory agencies is required before the pond design can be finalized.

The available area for the new lined CCR pond is 7 acres. Construction is planned to require 8 months including site prep and cleaning, cut and fill, and liner installation.

The project scope will include modifications to reroute various wastestreams to the new pond. The two CCR wastestreams are pumped by transfer systems. New lines will be routed to the pond using existing pipe racks and chases where available. The existing system treating the FGD wastewater prior to discharge to the East Ash Pond will be replaced or relocated to an area adjacent to the new lined CCR Pond. Tie-ins for the electrical supply and other utilities must be planned and coordinated with plant operations and it may be necessary to perform this work during an outage. An overall duration of 8 months is planned for construction of the new lined CCR Pond and rerouting the CCR lines from the East Ash Pond.

Following completion of construction, the system will undergo start-up and commissioning. This project phase will require 2 months and involves instrument loop checks, motor meggering, electrical system settings, overall system hydrostatic testing, mechanical operation of all rotating equipment and various other tasks to prepare the system for operation. Issues discovered during this period may require support from the equipment vendor to repair or replace damaged components. At the conclusion of this phase, a package with all checkout records will be produced.

Following the above and prior to operation, the pond construction must be certified to IDEM by a registered engineer. Certification requires record drawings of the final construction and various records verifying the installed pond meets the required standards. Two months is planned for assembly of this packet and IDEM review and release for operation.

A period of 1 month is allocated for initial operation, during which the process controls loops will be tuned and setpoints adjusted. A key objective of the run-in period is to verify the reliability of the system over a range of operating conditions. Issues that are identified during this phase may require support from the equipment vendor or modification of the system. At the completion of the initial operation period, all CCR flows to the East Ash Pond will cease and be redirected to the new pond.

5.2.2.7 Schedule Summary

Based on the schedule provided in **Appendix C**, conceptual design activities for the new lined CCR Pond and redirection of flows are currently underway. The path to alternative capacity will involve preliminary design, contractor selection, detailed design, procurement and construction. Based on this schedule, it is currently anticipated that flows to the East Ash Pond will cease on March 1, 2023. Throughout the design process, project management efforts will be made to identify schedule improvements.

5.2.2.8 Anticipated Worker Schedules (40 CFR 257.103(f)(1)((iv)(A)(3)(iv)

During construction of the new lined CCR Pond and infrastructure to redirect flows, the anticipated worker schedules will consist of 50-hour weeks. This will involve working 5 days per week, approximately 10 hours per day. If weather or other delays are encountered, the worker schedule may be adjusted (increased) to address this lost time and maintain project schedules.

5.3 Progress Toward Alternate Capacity (40 CFR 257.103(f)(1)(iv)(A)(4))

Part A (40 CFR 257.103(f)(1)(iv)(A)(4) requires a narrative discussion of the progress the Owner/Operator has made to obtain alternative capacity for the CCR and/or non-CCR wastestreams. The narrative must discuss all the steps taken, starting from when the Owner/Operator initiated the design phase up to the steps occurring when the

demonstration is being compiled. It must discuss where the facility currently is on the timeline and the efforts that are currently being undertaken to development alternative capacity.

An Environmental Compliance review for continued coal-fired operation at F.B. Culley was performed in 2019 and a Final Report issued in February 2020. The review encompassed the modifications required to comply with the final CCR Rule and ELG Rule and the proposed revisions. Recommendations for modifications to the plant were made in the report and have been summarized in this Work Plan. Summary of projects in progress is as follows:

- Construction of the new lined Contact Stormwater Pond is underway and expected to be completed by December 31, 2020. This pond will serve non-CCR flows currently being sent to the East Ash Pond beginning on or before July 1, 2021 (following flow redirection).

- Re-route of contact stormwater flows from the East Ash Pond to the new Contact Stormwater Pond is underway and expected to be completed by July 1, 2021.

- Design of the Unit 3 dry bottom ash system has been completed (initiated early 2018) and installation of the unit is complete as of November, 2020. (prior to the December 31, 2020 deadline in accordance with NPDES permit requirements). This effort has eliminated this flow to the East Ash Pond.

- Efforts have been initiated for fatal flaw evaluation and conceptual design of a new CCR Rule compliant surface impoundment in the vicinity of the new lined Contact Stormwater Pond and redirection of subject flows to this pond. As discussed in this document, this pond will serve CCR-flows that are currently managed by the East Ash Pond (Unit 2 Bottom Ash, Unit 2/3 FGD Wastewater-related flows). Once complete on or before March 1, 2023, operation of this new CCR Pond will result in cessation of all flows to the East Ash Pond.

- Study work and planning for the FGD Wastewater system has been ongoing since 2017. The early study work and planning included efforts to evaluate the potential for reducing flow volumes and meeting the constituent requirements of the FGD wastewater in order to determine whether the design requirements for a spray dryer system could be achieved. The selection of the ZLD technology was included in a filing to the IURC seeking approval for the capital expenditure. The order granting this approval was issued April 24, 2019. Planning and preparation for design initiation has been occurring throughout 2020 culminating in Owner's Engineer vendor selection in August 2020. Equipment specifications, vendor selection, and BOP design activities for the FGD Wastewater system began in September 2020. This effort is scheduled to be completed on July 1, 2023 (after initiation of the new CCR Pond operation). In the event this activity can be completed prior to operation of the new CCR Pond, this will result in early elimination of this flow to the East Ash Pond. However, due to the fact this project is not the fastest technically feasible timeline, ZLD technology is secondary to the new CCR Pond construction.

6 Compliance Certification and Additional Information (40 CFR § 257.103(f)(1)(iv)(B))

In accordance with *40 CFR § 257.103 (f)(1)(iv)(B),* the following information and attachments are submitted to demonstrate that the F.B. Culley Generating Station is in compliance with 40 CFR § 257 Subpart D – Standards for the Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments (CCR Rule).

In accordance with Federal CCR Rule requirements, groundwater monitoring wells were installed to evaluate the groundwater quality in the vicinity of the East Ash Pond and the West Ash Pond. The analytical results and subsequent ASD efforts (**Appendix H**) resulted in the identification of one constituent, molybdenum, at an SSL exceeding the Appendix IV GWPS at the East Ash Pond and the identification of two constituents, lithium and molybdenum, at an SSL exceeding the Appendix IV GWPS at the West Ash Pond. In response, Haley & Aldrich prepared a Corrective Measures Assessment (**Appendix J**) for the East Ash Pond. The Corrective Measures Assessment for the East Ash Pond evaluated the risk related to the molybdenum exceedances and determined there are “no adverse effects on human health or ecological receptors…” from groundwater at the East Ash Pond. The Corrective Measures Assessment for the West Ash Pond was initiated and is currently in progress. Semiannual groundwater sampling has been implemented to continue to monitor and evaluate groundwater and will continue through the closure and post-closure processes at each unit. Activities toward remedy selection are ongoing for the East Ash Pond and will be pursued for the West Ash Pond following completion of the Corrective Measures Assessment.

With respect to groundwater considerations, it should further be noted that the alternative capacity being pursued at F.B. Culley as discussed throughout this demonstration will result in closure of the East Ash Pond sooner than originally anticipated. The West Ash Pond closure design resulted in the excavation of nearly all of the CCR material in potential contract with groundwater. A small quantity of CCR may be in contact with groundwater during periods of prolonged wet weather and/or high river levels.

Compliance data required by Part A associated with the East Ash Pond is referenced in the sections below and provided in Appendices to this report. Supplemental data and information related to the West Ash Pond is included in an addendum to this report (**West Ash Pond Supplemental Attachments).**

6.1. Certification of Compliance

The F.B. Culley Generating Station is in compliance with the requirements of the CCR Rule. SIGECO manages the company website for the F.B. Culley Generating Station and it is kept up to date and contains all the necessary documentation. **Appendix D** includes the required certification of compliance.

6.2. Visual Representation of Hydrogeologic Information

6.2.1. Groundwater Monitoring Well Locations

Figures detailing the location of the groundwater monitoring wells in relation to the East Ash Pond at F.B. Culley are attached (**Appendix E**). Figures detailing the location of the groundwater monitoring wells in relation to the West Ash Pond at F.B. Culley are included in the addendum (**West Ash Pond Supplemental Attachments**). The figures were prepared by Haley & Aldrich.

6.2.2. Well Construction Diagrams

Well construction diagrams and boring logs including stratigraphic cross-sections for the East Ash Pond are attached (**Appendix F**). Well construction diagrams and boring logs including stratigraphic cross-sections for the West Ash Pond are included in the addendum (**West Ash Pond Supplemental Attachments**). The well construction diagrams were prepared by Haley & Aldrich.

6.2.3. Groundwater Flow Direction

Figures detailing the groundwater elevation contours of November 2016 and June 2017 for the East Ash Pond to account for seasonal variations are attached (**Appendix G**). Figures illustrating the groundwater elevation contours of April 2017, January 2018, April to August 2018, and December 2018, for the West Ash Pond are included in the addendum (**West Ash Pond Supplemental Attachments**) The figures were prepared by Haley & Aldrich.

6.3. Groundwater Monitoring Analytical Results

Tables summarizing the constituent concentrations of each groundwater monitoring well sampled at the East Ash Pond between 2016 and 2020 are attached (**Appendix H**). The January 2020 Groundwater Monitoring Reports (prepared by Haley & Aldrich) including the ASD efforts are also included in **Appendix H**. Tables summarizing the constituent concentrations of each groundwater monitoring well sampled at the West Ash Pond between 2019 and 2020 are included in the addendum (**West Ash Pond Supplemental Attachments**). The tables were prepared by Haley & Aldrich.

6.4. Description of Site Hydrogeology

A description of the site hydrogeology at the F.B. Culley Generating Station is attached (**Appendix I**). The description was prepared by Haley & Aldrich.

6.5. Corrective Measures Assessment

The corrective measures assessment report for the East Ash Pond is attached (**Appendix J)**. The report was prepared by Haley & Aldrich. The corrective measures assessment report is located on F.B. Culley's company website. (https://www.vectren.com/assets/downloads/planning/ccr/Culley-East-Ash-Pond-Corrective-Measures-Assessment-Report.pdf)

Groundwater sampling at the East Ash Pond identified one Appendix IV constituent, molybdenum, in exceedance of GWPS, and the Corrective Measures Assessment was implemented in response to these results. The Corrective Measures Assessment evaluated the potential risk the constituent posed and potential corrective measures to prevent further releases. Groundwater flow was evaluated and found to be radial with an overall flow direction from the upland areas north of the Ash Pond to the South. As discussed in the Corrective Measures Assessment, "Groundwater downgradient of the East Ash Pond is not used as a source of drinking water and is not flowing toward any groundwater supply wells." The risk assessment also demonstrated "no adverse effects on human or ecological health from groundwater uses resulting from coal ash management practices at the F.B. Culley Generating Station East Ash Pond". Potential corrective measures to prevent further releases were identified and evaluated. These measures include Monitored Natural Attenuation, Hydraulic Containment, and In-Situ Treatment. These evaluations are further discussed and compared in the Corrective Measures Assessment.

The West Ash Pond is currently undergoing the corrective measures assessment. The Notification of Initiation of Corrective Measures Assessment is included in the addendum (**West Ash Pond Supplemental Attachments)** and is located on F.B. Culley's company website. (https://www.vectren.com/assets/downloads/planning/ccr/Culley-West-Notification-of-Initiation-of-Corrective-Measures-2020.pdf)).

6.6. Progress Reports

The progress reports on corrective action remedy dated March 2020 and September 2020 are attached (**Appendix K**). The reports were prepared by Haley & Aldrich and are also located on the company CCR compliance webpage for the F.B. Culley facility.

March 2020 Report (https://www.vectren.com/assets/downloads/planning/ccr/Culley-East-Ash-Pond-Semi-Annual-Selection-of-Remedy-Progress-Report_2020March.pdf)

September 2020 Report (https://www.vectren.com/assets/downloads/planning/ccr/Culley-East-Ash-Pond-Semi-Annual-Selection-of-Remedy-Progress-Report_2020September.pdf)

The West Ash Pond is currently undergoing the corrective measures assessment; therefore, progress reports for the West Ash Pond have not been prepared as of the date of this report.

6.7. Structural Stability Assessment

The structural stability assessment report for the East Ash Pond is attached (**Appendix L**). The report was prepared by AECOM. The report is also located on F.B. Culley's company website. (https://www.vectren.com/assets/downloads/planning/ccr/Culley-East-Structural-Stability.pdf)

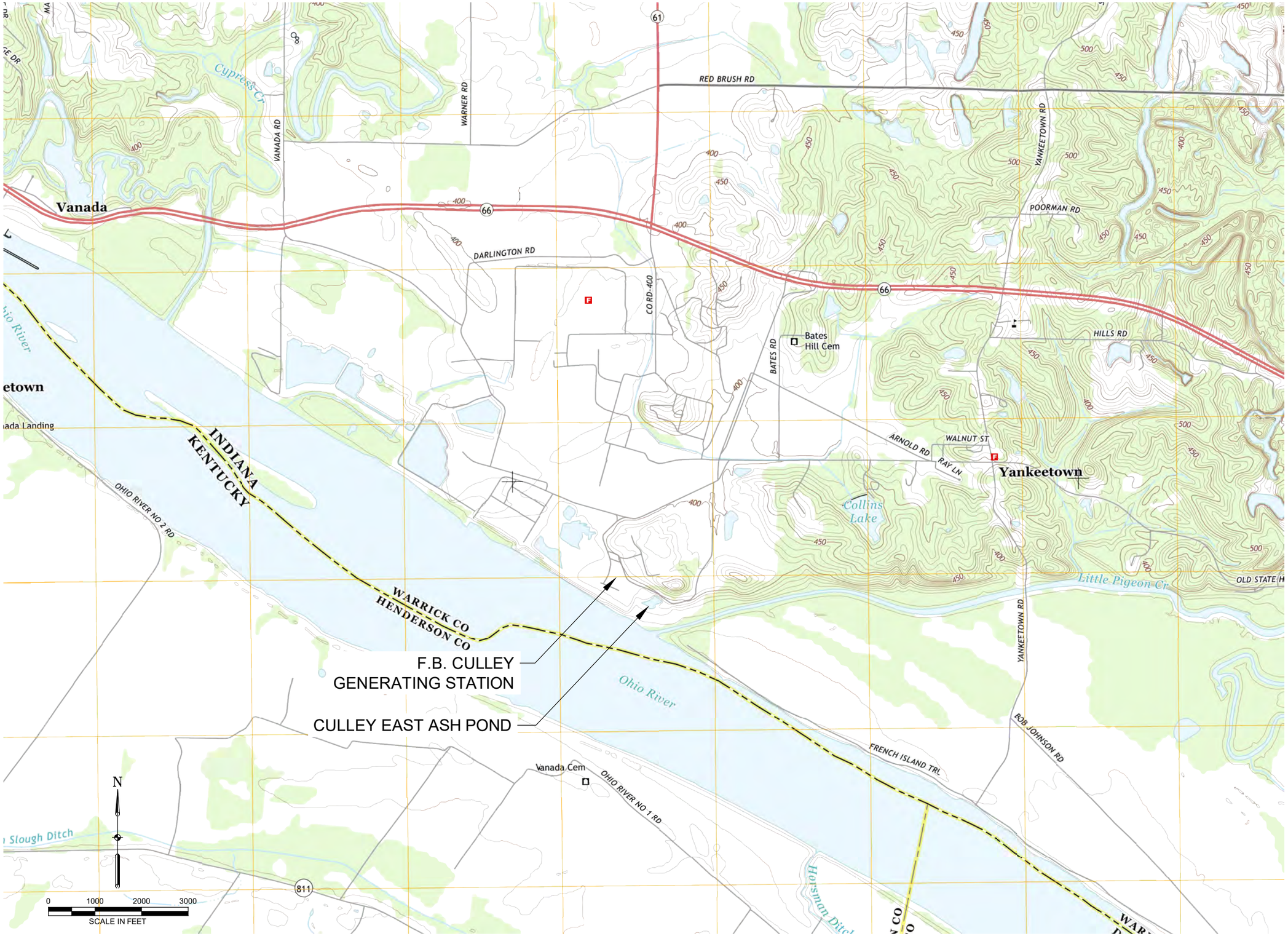
The structural stability assessment report for the West Ash Pond is not required as the unit was classified as "inactive" under the original 2015 CCR rule and was in the process of closure when the "Direct Final Rule" constituting a vacatur of 40 CFR §257.100 became effective.

6.8. Safety Factor Assessment

The factor of safety assessment report for the East Ash Pond is attached (**Appendix M**). The report was prepared by AECOM. The report is also located on F.B. Culley's company website. (https://www.vectren.com/assets/downloads/planning/ccr/Culley-East-Safety-Factor-Assessment.pdfThe factor of safety assessment report for the West Ash Pond is not required as the unit was classified as "inactive" under the original 2015 CCR rule and was in the process of closure when the "Direct Final Rule" constituting a vacatur of 40 CFR §257.100 became effective.

Figures

CARUSO, MICHAEL, 10/7/2016 3:12 PM



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SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
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1-800-227-1376 (phone)

F.B. CULLEY
GENERATING STATION
NEWBURGH, IN

DEVELOPMENT OF
ALTERNATIVE
CAPACITY
INFEASIBLE
DEMOSTRATION

ISSUED FOR CERTIFICATION

ISSUED FOR BIDDING	DATE	BY
ISSUED FOR CONSTRUCTION	DATE	BY

REVISIONS

NO.	DESCRIPTION	DATE
△		
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△		
△		
△		

AECOM PROJECT NO:	60442676
DRAWN BY:	MJC
DESIGNED BY:	MJC
CHECKED BY:	TLE
DATE CREATED:	8/18/2016
PLOT DATE:	4/22/2016
SCALE:	AS SHOWN
ACAD VER:	2014

SHEET TITLE

LOCATION MAP

FIGURE 1

AECOM DRAWING PATH: P:\Projects\Environmental\60442676_VectrenCCR\7.0_CAD_GIS\7.04_Plan_Sheets\CULLEY-LOCATION MAP.dwg

AECOM
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F.B. CULLEY GENERATING STATION
NEWBURGH, IN

DEVELOPMENT OF ALTERNATIVE CAPACITY INFEASIBLE DEMONSTRATION

ISSUED FOR CERTIFICATION

ISSUED FOR BIDDING - - (DATE BY)

ISSUED FOR CONSTRUCTION (DATE BY)

REVISIONS

NO.	DESCRIPTION	DATE
1		
2		
3		
4		
5		

AECOM PROJECT NO:	60442676
DRAWN BY:	JMW
DESIGNED BY:	JMW
CHECKED BY:	RJB
DATE CREATED:	12/19/2018
PLOT DATE:	12/19/2018
SCALE:	AS SHOWN
ACAD VER:	CIVIL 3D 2018

SHEET TITLE

SITE MAP

FIGURE 2

N

0 200 400 600
GRAPHIC SCALE (IN FEET)

Appendices

Appendix A
IURC Order in Cause No. 45052

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

SNK

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH") FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE GAS TURBINE GENERATION FACILITY ("CCGT"); (2) APPROVAL OF ASSOCIATED RATEMAKING AND ACCOUNTING TREATMENT; (3) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR COMPLIANCE PROJECTS TO MEET FEDERALLY MANDATED REQUIREMENTS ("CULLEY 3 COMPLIANCE PROJECT"); (4) AUTHORITY TO TIMELY RECOVER 80% OF THE COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CULLEY 3 COMPLIANCE PROJECTS THROUGH VECTREN SOUTH'S ENVIRONMENTAL COST ADJUSTMENT MECHANISM; (5) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE REVENUE REQUIREMENT FOR COSTS, INCLUDING CAPITAL, OPERATING, MAINTENANCE, DEPRECIATION, TAX AND FINANCING COSTS ON THE CULLEY 3 COMPLIANCE PROJECT WITH CARRYING COSTS AND (B) POST-IN-SERVICE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE CCGT AND CULLEY 3 COMPLIANCE PROJECT UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; (6) ONGOING REVIEW OF THE CCGT; (7) AUTHORITY TO IMPLEMENT A PERIODIC RATE ADJUSTMENT MECHANISM FOR RECOVERY OF COSTS DEFERRED IN ACCORDANCE WITH THE ORDER IN CAUSE NO. 44446; AND (8) AUTHORITY TO ESTABLISH DEPRECIATION RATES FOR THE CCGT AND CULLEY 3 COMPLIANCE PROJECT ALL UNDER IND. CODE §§ 8-1-2-6.7, 8-1-2-23, 8-1-8.4-1 *ET SEQ*, 8-1-8.5-1 *ET SEQ.*, AND 8-1-8.8 - 1 *ET SEQ.*	)	CAUSE NO. 45052 APPROVED: APR 24 2019

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
David E. Veleta, Senior Administrative Law Judge

On February 20, 2018, Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South") filed its verified petition in this Cause seeking, among other relief, certificates of public convenience and necessity for a new duct-fired F-class 2x1 combined cycle gas turbine ("CCGT") providing 700 MW of baseload and 150 MW of peaking capacity pursuant to Ind. Code ch. 8-1-8.5 and for certain environmental projects at its Culley Unit 3 generating station pursuant to Ind. Code ch. 8-1-8.4. Petitions to intervene were filed by the Vectren Industrial Group; Valley Watch, Inc., the Citizens Action Coalition of Indiana, Inc., and the Sierra Club ("Joint Intervenors"); the Indiana Coal Council, Inc. ("ICC"), Sunrise Coal, and Alliance Coal, LLC (the "Coal Parties"); SABIC Innovative Plastics Mt. Vernon, LLC; St. Joseph Energy Center, LLP; St. Joseph Phase II LLC; and Evansville Western Railway. All of these petitions to intervene were subsequently granted. A public field hearing was held in Evansville on July 11, 2018, at which time members of the public presented testimony. The Indiana Utility Regulatory Commission ("Commission") held an evidentiary hearing at 9:30 a.m. on October 9, 2018, in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana.

Based upon the applicable law and the evidence presented, the Commission finds:

1. **Notice and Jurisdiction.** Notice of the hearings in this Cause was given and published as required by law. Vectren South is a "public utility" as defined in Ind. Code § 8-1-2-1(a) and Ind. Code § 8-1-8.5-1, an "energy utility" as defined in Ind. Code § 8-1-8.4-3, and an "eligible business" as defined in Ind. Code § 8-1-8.8-6. Vectren South is subject to the jurisdiction of this Commission in the manner and to the extent provided by Indiana law. Pursuant to Ind. Code chs. 8-1-8.5 and 8-1-8.4, Vectren South may seek Commission approval of Certificates of Public Convenience and Necessity. Accordingly, the Commission has jurisdiction over Vectren South and the subject matter of this proceeding.

2. **Vectren South's Characteristics.** Vectren South is an operating public utility incorporated under the laws of the State of Indiana, with its principal office and place of business in the City of Evansville. Vectren South provides electric and gas utility service to the public in Indiana and is subject to the regulation by this Commission in the manner and to the extent provided by the laws of the State of Indiana. This proceeding pertains to Vectren South's electric utility business. Vectren South renders retail electric utility service to approximately 145,000 customers in seven counties in southwestern Indiana, and owns, operates, manages and controls electric generating, transmission and distribution plant, property and equipment and related facilities which are used and useful for the convenience of the public in the production, transmission, delivery and furnishing of electric energy, heat, light and power for residential, commercial, industrial and municipal uses. Vectren South furnishes such electric utility service to retail customers located in Vanderburgh, Posey, Gibson, Pike, Warrick, Dubois and Spencer Counties, with a major portion of such customers residing in and around the City of Evansville, Indiana. Vectren South owns and operates 1,248 megawatts ("MW") of total net generating capacity. This generation capacity is primarily derived from the following five coal-fired baseload units providing a total of approximately 1,000 MW: A.B. Brown 1 (245 MW), A.B. Brown 2 (245 MW), F.B. Culley 2 (90 MW), F.B. Culley 3 (270 MW) and Warrick Unit 4 (150 MW[1]). Vectren South procures 100% of its coal supply from mines located in Indiana.

[1] Represents Vectren South's ½ interest in Warrick Unit 4, a 300 MW unit.

Vectren South's operations are subject to federal, state and local rules promulgated and/or implemented by, among others, the federal Environmental Protection Agency ("EPA"), the Indiana Department of Environmental Management ("IDEM") and by the Environmental Rules Board of the State of Indiana. Such rules establish environmental compliance standards that govern emissions and discharges from Vectren South's electric generating units.

3. Overview of the Evidence.

A. Condition of Current Fleet.

i. Vectren South. The main drivers behind Vectren South's proposal are the age and operating characteristics of Vectren South's existing baseload capacity and the upcoming deadlines for significant capital investments to address environmental regulations. Mr. Wayne D. Games, Vice President of Power Supply at Vectren South, testified regarding the condition of Vectren South's current generation fleet and the challenges facing the fleet. He testified Vectren South's fleet consists of five coal-fired baseload units totaling 1,000 MW. Mr. Games further testified that growth of renewable energy sources and low natural gas prices have negatively affected MISO's dispatch of Vectren South's coal-fired units. Instead of running continuously, Vectren South's units are now cycled up and down throughout the day, or are shut down altogether, decreasing unit efficiency and increasing wear and tear on the units. Mr. Games testified that because the units were not designed to cycle in this manner, the units cannot effectively compete with gas units in particular, which have far better operating flexibility. Continued market reforms are exacerbating this issue and jeopardizing unit availability and reliability.

Mr. Games also explained that the individual units face additional operating challenges. In particular, the A.B. Brown Units rely on scrubbers that utilize a technology that has been abandoned by the industry because of its high variable costs and the vapor it emits which causes corrosion of the unit structure. The scrubbers are already past their expected 30 year design life and present a significant risk to reliability and maintenance costs. He explained that Culley Unit 2 is Vectren South's oldest and smallest unit and that it has the worst heat rate of any coal unit in the state. Finally, he explained the unique circumstances related to the joint operation of the Warrick Unit which creates uncertainty as to the duration of its operation.

Ms. Angila Retherford, Vice President of Environmental Affairs and Corporate Sustainability, testified regarding two new major federal regulatory initiatives – Effluent Limitations Guidelines ("ELG") and Coal Combustion Residuals ("CCR") - impacting Vectren South's coal-generating units. Absent substantial investment at all of Vectren South's coal plants, they must cease operations by December 31, 2023. Ms. Retherford described Vectren South's environmental compliance strategy for the A.B. Brown and Culley units and testified future compliance costs were modeled in Vectren South's 2016 Integrated Resource Plan ("IRP") under the business as usual scenario. Ms. Retherford testified these rules and other existing federal regulatory requirements will require Vectren South to make significant further investment at the A.B. Brown and Culley generating facilities to continue their operation.

ii. Non-Utility Parties.

(1) OUCC. OUCC witnesses Lauren M. Aguilar – Utility Analyst, Anthony A. Alvarez – Utility Analyst and Peter M. Boerger – Senior Utility Analyst testified regarding Vectren South's request for a CPCN to construct the CCGT. These OUCC witnesses testified Vectren South's decision to construct the CCGT is premature because Vectren South has not explored all practical alternatives to extend the life of the A.B. Brown units. OUCC Witness Aguilar ultimately recommended that the decision to build the CCGT be delayed until the end of the 2019 IRP process, in order to allow Vectren South the opportunity to evaluate additional alternatives. The OUCC offered no alternative resource proposal, but argued for a "blended approach" with the possible continued use of existing assets, and suggested that the necessary expenditures to continue use of these assets could be viewed as buying an "option on the future." The OUCC witnesses asserted that deferring any decision until the conclusion of the 2019 IRP process would still allow sufficient time to take action without affecting reliability.

(2) Coal Parties. The Coal Parties' witnesses generally testified that Vectren South should wait to transition its baseload generation from coal to natural gas because the environmental regulations driving the transition, the ELG and CCR rules, are in flux and not yet final. Specifically, the Coal Parties' witnesses testified that recent and anticipated EPA reconsiderations of the ELG and CCR regulations, as well as the potential stay or replacement of the Clean Power Plan ("CPP"), create the potential scenario where Vectren South could operate the A.B. Brown and Culley units beyond 2023 without the need to make material investments in compliance measures. Coal Parties witness Michael J. Nasi – Partner with the law firm of Jackson Walker L.L.P. – further testified that Vectren South's decision to retire its coal plants is premature. He recommended that the decision be delayed until the environmental regulations driving the decision are better understood. With respect to the A.B. Brown units, the Coal Parties suggested that Vectren should investigate an alternative scrubber technology marketed by a Chinese firm to replace the existing dual alkali scrubbers. This technology which uses ammonia creates material that can be sold as fertilizer with revenues used to offset variable operating costs of the scrubber.

iii. Vectren South Rebuttal. Ms. Retherford, who is also a licensed attorney, testified regarding the risks associated with continuing to operate Vectren South's coal-fired fleet and delaying the decision to construct the proposed CCGT. Ms. Retherford testified that recent legal developments related to the CCR rule have made it impossible for Vectren South to continue operating its coal-fired fleet beyond 2023 without significant capital investment. She testified that the current water discharge permits require, and the groundwater monitoring results at the A.B. Brown and Culley ash ponds confirm, that Vectren South must cease discharging coal ash by December 31, 2023, pursuant to the ELG and CCR rules. She also testified that *Utility Solid Waste Activities Group v. Environmental Protection Agency*, 901 F.3d 414 (D.C. Cir. 2018), 2018 U.S. App. LEXIS 23547, confirms that the CCR Rule is final, including the final compliance deadlines at issue in this proceeding. Ms. Retherford testified that pond retirement delay is not an option, and therefore Vectren South must either make investments to comply with the CCR rule or retire the plants before 2024.

In response to the Coal Parties' position that the current administration could alleviate environmental carbon regulations applicable to the coal units, Ms. Retherford testified that the Administration's proposed replacement for CPP does not alleviate the problems. On August 31, 2018, the EPA published its proposed Affordable Clean Energy ("ACE") rule in lieu of CPP. She explained

that ACE would increase uncertainty and could actually increase the cost of compliance. For units with high heat rates – such as A.B. Brown – ACE would cause significant future compliance costs.

Vectren South also presented the testimony of Richard McMahon from Edison Electric Institute ("EEI") regarding the growing importance of Environmental, Sustainability and Governance ("ESG") reporting and metrics to the financial community, and the focus of all public electric utilities on being responsive to these topics and establishing explicit carbon reduction targets as part of their public disclosures. Mr. McMahon described the coordinated electric industry response to the demands for ESG reporting, and provided specific examples of lenders and large institutional investors who are putting pressure on companies to transition from dependence on coal units. He explained that Vectren South's 60% carbon emission reduction was in line with similar targets publicly disclosed by its electric utility peers. He also presented information regarding the industry transition from reliance on coal to use of gas as part of the ability to reduce carbon emissions.

As to the potential for alternative scrubbers, Vectren South witness Paul Farber – Principal of P. Farber & Associates, LLC – testified regarding the shortcomings of the technologies presented by Sunrise Coal witness Dombrowski and OUCC witness Aguilar and explained why, from an operational and financial perspective, it would not be prudent for Vectren South to adopt those technologies. With respect to the ammonia based scrubber technology presented by witness Dombrowski, Mr. Farber testified the technology has very limited deployment in the United States and would present a number of operational challenges if installed at baseload coal-fired units like A.B. Brown. These uncertainties and risks posed by adoption of this technology include its cost, its impact on operation of the units (including that it might cause Vectren South to be out of compliance with regulations for other constituents such as mercury and particulate matter absent further types of investments), the unknown ability to sell fertilizer output, and the complications associated with dealing with vendors with no domestic history. He discussed in depth the substantial operational burden and health and Homeland Security risk associated with handling the large amount of ammonia required by such a scrubber. Mr. Farber concluded that the Coal Parties had failed to provide any evidence that the capital costs of this scrubber technology would be any less than the scrubber modeled in Vectren South's 2017 IRP Update. In rebuttal testimony, Jon K. Luttrell, Senior Vice President, Utility Operations and President of Vectren Utility Holdings, Inc., also discussed the cyber security complications and risks posed by adoption of Chinese scrubber technology.

Mr. Farber also responded to OUCC witness Aguilar's criticism that Vectren South "only" evaluated wet limestone and her presentation of potential costs for other technologies. Mr. Farber testified that dry scrubbing is not an applicable technology at A.B. Brown for technical and economic reasons, and therefore it was logical for Vectren South to evaluate wet limestone technology at A.B. Brown. He also testified the cost estimates presented by Ms. Aguilar are not comparable cost estimates to replace the existing scrubbers at A.B. Brown Units 1 and 2.

Mr. Games testified on rebuttal that there simply is no time to delay a decision and await the outcome of another IRP. The Vectren South coal units must be retired or retrofitted by December 31, 2023. Given that there has been nothing to suggest more delay would change the overall economics that the F-class 2x1 CCGT is part of the lowest cost solution under every scenario, there is no reason to believe that modeling in the next IRP would change that result. Mr. Games provided an exhibit setting forth a timeline showing that a delay to allow the next IRP to proceed would leave Vectren South with essentially no baseload capacity for almost three years. During that entire period, Vectren

South customers would be completely exposed to the market for capacity and energy. Per the redirect examination of Justin M. Joiner, Director of Regulatory Policy and MISO Affairs for Vectren Utility Holdsings, Inc. ("VUHI"), this would be during the period when MISO is projecting its largest capacity shortfall for Zone 6 (Indiana). The Commission's Director's Report states "[a]n appropriate planning aspiration is to maintain flexibility while also waiting as long as reasonably possible to commit to a resource." Mr. Games testified on cross-examination that Vectren South has waited as long as reasonably possible.

B. Modeling and Results. Only two parties presented modeling evidence and results. Vectren South presented the modeling from the 2017 IRP Update and the 2016 IRP. Sunrise Coal Witness Philip Hayet presented alternative modeling whereby Vectren South's Preferred Portfolio was delayed by seven years in order to allow existing coal units to continue to operate beyond 2023. Other parties offered criticism of Vectren South's modeling but presented no alternative modeling.

i. 2016 IRP. Vectren South's case was filed in the context of a proposed new rule to govern the IRP process. While our new rule was not effective during the 2016 IRPs, all participating electric utilities complied. This new process is significantly more transparent. It includes the participation of stakeholders, the convening of public meetings, and the submission of and response to comments. Mr. Matt Rice, Director – Research and Energy Technologies, testified regarding Vectren South's IRP process and the results of that process. Mr. Rice described Vectren's approach to its 2016 IRP process and testified Vectren South engaged several industry experts, including Burns & McDonnell and Pace Global, to conduct technical modeling. Mr. Rice testified Vectren South worked with these experts and IRP stakeholders to conduct scenario analysis to evaluate 15 portfolios, each representing a different mix of supply and demand side resources to meet customer load over a 20-year time horizon. He further testified Vectren South worked with Pace Global to conduct a risk analysis and evaluate the 15 portfolios using a balanced scorecard approach. From this analysis, Vectren South identified the "preferred portfolio" which consisted of replacing all existing coal fired generation other than Culley Unit 3 as well as gas peaking units Northeast 1 and 2 and Broadway 1 by 2024 with an F-class .05 Fired CCGT. Mr. Rice testified Vectren South incorporated stakeholder input throughout the process and described the steps Vectren South took to engage stakeholders both before and during the process. This engagement included having stakeholders develop two portfolios which were then modeled and included in the risk analysis.

Mr. Matthew Lind – Associate Project Manager, Burns & McDonnell – described the modeling Burns & McDonnell conducted in the 2016 IRP on behalf of Vectren South to evaluate its resource needs over the next 20 years. He testified the results of Burns & McDonnell's modeling identified a low-cost portfolio that ceased coal operations at Vectren South's coal fired facilities (A.B. Brown Units 1 and 2, F.B. Culley Units 2 and 3, and Warrick Unit 4) and replaced this capacity and energy with the combined cycle facility proposed here along with a simple cycle facility. Mr. Gary Vicinus – Managing Director for Utilities at Pace Global – described Pace Global's role in identifying and defining the objectives, metrics and risks in order to select the preferred portfolio among the many options. He testified Pace Global used a balanced scorecard approach to apply a risk analysis to a selection of portfolios ultimately to recommend a preferred portfolio. Mr. Vicinus further testified regarding revisions Pace Global made to its risk analysis and explained that, even with these revisions, the risk analysis indicated the preferred portfolio was the best approach.

Mr. Rice described the preferred portfolio and explained why it ranked the best on the balanced scorecard. He testified it performed the best because the portfolio is diversified as it contemplates keeping FB Culley 3 (a coal unit) and existing wind contracts, building a CCGT and introducing solar and continuing to offer energy efficiency. He further testified it is among the lower cost portfolios (within 4% of the predominantly gas lowest cost portfolio) and ultimately performed best overall when viewed across multiple measures on the balanced scorecard. Because the all-gas portfolio represented the lowest cost portfolio, it is the retention of Culley Unit 3 and the accelerated addition of the 50 MW solar project that increases the costs of the Preferred Portfolio over the lowest cost all-gas portfolio. Retention of coal and the addition of solar are essential to diversity.

ii. 2017 IRP Update. Mr. Lind testified Vectren South requested Burns & McDonnell to update the 2016 IRP modeling and the re-evaluated low-cost portfolio was consistent with the low-cost portfolio identified in the 2016 IRP. He explained that several modeling inputs were updated, including the capital cost for solar resources, variable production costs and revenue requirements for existing units, an assumed operation of Warrick Unit 4 through 2023, and updated cost assumptions for capacity, energy, natural gas, coal, and energy efficiency.

OUCC witness Peter Boerger testified regarding Vectren South's 2017 IRP Update economic modeling. Mr. Boerger testified that Vectren South's 2017 IRP Update did not adequately consider viable options for serving its customers—including making use of existing resources and adequately considering the addition of a smaller CCGT unit rather than the 2x1 unit being proposed. Mr. Boerger also testified Vectren South's modeling of the proposed CCGT understated its capital cost by $200 million, an error which disadvantaged other options in Vectren South's modeling. Mr. Boerger ultimately recommended Vectren South reevaluate its future needs and model additional alternatives.

CAC witness Tyler Comings – Senior Researcher at Applied Economics Clinic – testified on behalf of the Joint Intervenors. Mr. Comings criticized Vectren South's modeling, testifying it was too convoluted to yield a sufficiently transparent or credible result. He testified Vectren South used too many models in the selection of the preferred portfolio and that the use of many models created ample opportunity for flawed and/or inconsistent input assumptions and other settings that could create bias in favor of the preferred plan. Mr. Comings ultimately recommended Vectren South's petition be denied because, in his view, Vectren South did not provide sufficient justification for its choice to build the CCGT and continue the operation of Culley 3.

Indiana Coal Council witness Emily Medine – Principal in the consulting firm of Energy Venture Analysis, Inc. – also testified regarding Vectren South's modeling. Witness Medine testified Vectren South should have fully updated its 2016 IRP analysis, including its scenario analysis, in order to confirm its preferred resource portfolio. She further testified that such an update should include a broader analysis (including sensitivity analyses) of the relevant assumptions and factors as of a time as close to Vectren South filing its Petition as possible. Ms. Medine attributed the decision to build a CCGT to financial motivations and also opined that approval of the CCGT might be a condition to closing the Vectren South merger transaction.[2] Ms. Medine recommended that Vectren South's Petition be rejected because Vectren South has failed to show that proceeding with building the CCGT at this time is prudent, less risky, and a better decision for both customers and the environment.

[2] While this case was pending, it was announced publicly that Vectren South's holding company was the subject of an acquisition at the holding company level, which was the subject of Cause No. 45109.

Mr. Lind responded to Mr. Boerger's testimony about an alleged $200 million "error." He explained that approximately $67 million of the alleged error identified by Mr. Boerger was due to Mr. Boerger's mistaken assumption about whether modeled option costs are stated in 2017 dollars or nominal dollars in the year of incurrence. The remainder is due to Mr. Boerger's efforts to compare apples and oranges. As Mr. Lind explained, the modeling was done prior to the more refined cost estimates for the CCGT that were developed for this case. Rather than based on a design level accuracy of plus/minus 50%, the CCGT design has been refined to a plus/minus 10%. All of the other portfolios were still at plus/minus 50%. As Mr. Lind explained, to compare the other less refined portfolios to the more refined CCGT would require some additional risk factor for the other portfolios. But even if one includes the updated cost estimate, Mr. Lind testified that it doesn't change that the lowest cost portfolios still include the CCGT. Mr. Lind prepared additional modeling involving coal-to-gas conversion (which we will describe later) and which did include the more refined CCGT cost estimate. While this additional modeling used the more precise CCGT cost and therefore impacted every portfolio that included the CCGT by increasing the overall net present value ("NPV") by $54 million, the portfolios that included the CCGT were still the lowest cost portfolios compared to portfolios that did not include the CCGT. Regarding the use of the models, witnesses Lind and Vicinus confirmed that the process and modeling for Vectren South's IRP and risk analysis were consistent with the resource planning approach Pace and Burns & McDonnell have used for numerous other utilities.

(iii) Size of the Proposed CCGT. Joint Intervenors' witness Tyler Comings testified regarding the size of the proposed CCGT. Witness Comings testified that Vectren South has not provided a sufficient justification to build a CCGT of the size included in its proposal. Witness Comings also criticized Vectren South's Request for Proposals ("RFP") (which we will describe in greater detail later) which sought resources between 600 and 800 MW, because he believed Vectren South could have considered combinations of small resources that added up to 600 MW. He further testified that considering smaller options would limit the market risk exposure for ratepayers, as well as permit a combination of bids to make up a least cost alternative. Mr. Comings testified that in order to reduce ratepayers' risk, Vectren South should explore cost effective alternatives that do not require intensive capitalization, but still provide benefits to ratepayers.

OUCC witness Anthony Alvarez also testified regarding the size Vectren South is proposing for the CCGT. Mr. Alvarez testified that Vectren South currently has excess supply, and there is no resource shortfall or inadequacy that supports Vectren's proposed 850 MW CCGT. He also questioned the load forecast used in the IRP and testified Vectren South has excess supply after serving its peak load and therefore has excess capacity to offer into the market and serve new customers.

Industrial Group witness Michael Gorman also testified regarding the size of Vectren South's proposed CCGT. Mr. Gorman testified Vectren South's proposal to build an 850 MW CCGT will result in excess capacity and have a compound impact on Vectren South's cost of service because the plan increases the costs of new generation resources and results in unrecovered stranded costs from the retired resources. Mr. Gorman recommended the Commission implement mitigation measures to reduce the cost burden on customers related to stranded costs and the cost of the new CCGT. He also recommended the Commission modify the off-system sales margin treatment so that 100% of future wholesale revenues be provided to customers to offset the cost of the proposed resource plan.

Vectren South witness Carl Chapman testified on rebuttal regarding Vectren South's decision to construct an 850 MW CCGT. Mr. Chapman explained the CCGT is essentially two units -- a 700 MW baseload unit to replace 730 MWs of retiring coal unit capacity and 150 MWs of duct fired peaking capacity to replace older peaking units and provide available low cost capacity for growth and wholesale sales opportunity. The additional peaking capacity is provided by the decision to duct-fire the CCGT. The incremental cost of duct-firing the CCGT is $15 million, and that decision must be made at the time the CCGT is constructed (i.e., it cannot be added at a later time.) Mr. Chapman testified that if only the unfired 700 MW baseload CCGT is built, then by 2025, Vectren South has a projected surplus above MISO's Planning Reserve Margin ("PRM") (which fluctuates) of only 51 MW. He further testified that by 2030, the surplus is only 5 MWs and by 2031 Vectren South will fail to meet its PRM. He testified that by 2036, Vectren South will be short 39 MWs, and all of this assumes Vectren South will not add significant new load. Mr. Chapman testified that with its low capital cost, firing makes sense from a customer perspective. For an incremental cost of 2%, the firing provides a 21% increase in capacity. Nevertheless, if the Commission approves the baseload 700 MW CCGT without firing, Vectren South will proceed to construct the unfired CCGT to replace its baseload coal units. He stated that Vectren South would also consider investing the incremental $15 million to duct-fire the unit and be at risk to recoup its investment via retention of the wholesale revenue produced by that peaking capacity.

Mr. Chapman also testified regarding Industrial Group witness Gorman's recommendation that Vectren South pass off-system sales margins on to retail customers. Mr. Chapman testified that Vectren South has decided to commit to provide 100% of wholesale sales revenue from the CCGT (baseload and peaking) to customers. Mr. Chapman explained that once the CCGT is placed in rate base, the benefits from the wholesale revenue produced by the unit will go to reduce customer costs. Mr. Chapman testified that providing 100% of wholesale revenue to customers further improves the NPV of the CCGT, will provide a larger offset to customer costs in general, and adds even more support to the $15 million incremental investment to duct fire the unit.

C. <u>Coal Parties' Modeling</u>. Indiana Coal Council, Inc. witness Philip Hayet – Vice President of J. Kennedy and Associates, Inc. – testified regarding Vectren South's 2016 IRP modeling and the 2017 IRP Update. Mr. Hayet testified that Vectren South's modeling analyses were flawed due to errors, inconsistencies, and a lack of consideration of important factors. Mr. Hayet performed his own analysis and testified that using the same model with certain corrections, including a deferral of a decision to add a CCGT, produced a slightly lower cost result on a NPV basis. He predicated his modeling on the assumption that the A.B. Brown 2 scrubber will continue to operate reliably through 2030. He ultimately recommended that Vectren South defer its decision to construct the CCGT.

On rebuttal, Vectren South witness Matthew Lind testified regarding Indiana Coal Council witness Hayet's alternative modeling. Mr. Lind testified that when Mr. Hayet's modeling is corrected for obvious errors, it reaches the same preferred portfolio conclusion as Vectren South's modeling. Mr. Lind provided corrections to Mr. Hayet's modeling in the form of an updated Strategist model and spreadsheets documenting the corrections. Mr. Lind outlined each of the errors he identified in Mr. Hayet's modeling and the impact of the individual errors on his analysis. The first of several errors he identified was that Mr. Hayet failed to include cost escalation during the seven years of delay that he was urging and that correcting this error alone would change Mr. Hayet's overall conclusion that delay would be less costly. Mr. Lind also testified regarding the cumulative effect of

addressing all of the errors. As part of this analysis, Mr. Lind testified that he included the increased cost of the CCGT to reflect the more recent cost estimates based on a plus or minus 10% confidence level. He testified that when correcting Mr. Hayet's modeling for all of these errors and inconsistencies, the NPV favors Vectren South's preferred portfolio, even under Mr. Hayet's no carbon regulation scenario. Witness Hayet corrected his testimony after Mr. Lind filed his rebuttal to add the escalation during the period of delay he was urging, and this correction changed his original conclusion that delay was less expensive. Mr. Hayet did not address the other modeling issues raised by Mr. Lind.

Mr. Games' rebuttal testimony also addressed witness Hayet's assumption that the A.B. Brown 2 unit and scrubber could be operated without added cost and reliability risk through 2030. Apart from the reliability issues created by the frequent cycling of the unit, he explained the structural damage resulting from the corrosive environment created by the unique characteristics of these scrubbers, and based on his direct experience with this equipment, Mr. Games concluded that he could not agree that it would be prudent to continue to operate the A.B. Brown 2 scrubber for another 12 years beyond 2018.

D. Renewables and All-Source RFP. Joint Intervenor witness Tyler Comings criticized the costs assumed in Vectren South's modeling for most renewable energy sources. Mr. Comings testified that Vectren South's forecast of the capital costs of future wind resources is higher than he would have recommended for the type of planning analysis and its forecast of the fixed O&M costs are lower. Mr. Comings recommended the use of the National Renewable Energy Laboratory's Annual Technology Baseline ("ATB") to develop the forecasts. With respect to future solar resources, Mr. Comings testified Vectren South's forecasts are too high for both the capital and fixed O&M costs. Mr. Comings recommended the reliance on the ATB to develop wind and solar price forecasts. For utility-scale PV, he testified that the ATB midpoint projection would be appropriate. As part of his discussion of renewable costs, he noted that Northern Indiana Public Service Company ("NIPSCO") had recently conducted an RFP and obtained solar and wind bids. Mr. Comings testified that Vectren South's overestimation of renewable costs compared to the ATB data biased the modeling results against renewable resources in favor of non-renewable resources, such as natural gas.

On rebuttal, Mr. Lind responded to Mr. Comings' testimony related to the cost of renewables included in Vectren South's modeling. With respect to wind resources, Mr. Lind noted that prior to revising his testimony, Mr. Comings' originally filed testimony included an inaccurate and inappropriate comparison of assumed capital cost for wind resources between Vectren South and ATB because Mr. Comings failed to account for the declining cost curve over time utilized by Vectren South. Mr. Lind testified that when Mr. Comings updated his testimony to reflect this decline, he recognized that Vectren South's wind costs are only "slightly higher" than what Mr. Comings recommends. Mr. Lind further testified that even with this correction, Mr. Comings' comparison to the ATB figures is incorrect because the ATB figure excludes a 2.1% construction finance factor and is thus understated. Mr. Lind testified that when the 2.1% construction finance factor is included, the ATB capital cost will exceed Vectren South's modeled capital cost for wind over more than half of the planning period. Mr. Lind pointed out that Vectren South assumed a higher capacity factor than the ATB survey and also assumed lower O&M costs compared to the ATB survey, and as a result, it is likely that the wind prices recommended by Mr. Comings are actually higher than those modeled by Vectren South.

With respect to Mr. Comings' criticisms of Vectren South's solar costs, Mr. Lind testified Mr. Comings again failed to account for the declining cost curve over time in the original version of his testimony. Mr. Lind further testified that while Mr. Comings did update his comparison to reflect the decline, he did not update it to include the 2.1% construction finance factor in the ATB comparison. Moreover, Mr. Lind explained that the national survey costs relied upon by Mr. Comings were presented on a direct current (DC) basis, whereas the 2017 IRP Update stated cost in terms of alternating current (AC), thus requiring that Comings' costs be converted to AC to allow for a valid comparison to be made. When correcting for these additional errors, Mr. Lind testified the solar costs used by Mr. Comings and Vectren South are nearly consistent over the last half of the study period and fairly similar from 2024 onward, which is the point at which capacity is needed.

Mr. Lind also testified regarding the impact of network upgrades and congestion costs on a portfolio that would rely more heavily on renewables. Mr. Lind testified that a portfolio which would rely heavily on renewables to supply power to Vectren South's customers is more likely to source some or all of these resources remote to Vectren South's service territory given the acreage required for such projects, the grid issues that can be encountered, and the enhanced production that can be obtained in certain locations (e.g., northern Indiana). Mr. Lind explained that when significant amounts of power are sourced from off-system resources, congestion costs to Vectren South's customers increase substantially. Because such costs were not part of the 2017 IRP Update assumptions, Mr. Lind concluded that any small differences between the solar costs presented by Mr. Comings and those modeled by Vectren South would be more than offset by the congestion costs associated with greater reliance on such resources. Finally, Mr. Lind noted that even assuming lower renewable costs could be achieved, such resources would likely displace Culley Unit 3's 270 MWs of capacity because that could be done incrementally to reduce the effects of network upgrades and congestion, whereas the CCGT would remain the optimal low cost choice to replace the remaining 730 MWs of retiring coal capacity in 2023. Further, wind and solar are intermittent sources of power; given that Culley Unit 3 would be Vectren South's only baseload capacity under its preferred portfolio, dispatchable baseload generation from a CCGT provides greater flexibility to respond to intermittent resources.

E. Capacity Price Forecasts. Mr. Comings testified regarding Vectren South's ability to purchase future needed capacity from the MISO market. Mr. Comings testified that Vectren South overestimated future capacity prices in MISO in its modeling, and in reality, the MISO market has had an oversupply of resources and tempered demand, leading to low capacity prices. He testified Vectren South's assumption of higher capacity prices is critical, because it makes the economics of building a new resource more attractive. He concluded that Vectren South was placing risk on its customers if the price of capacity is lower. To reach his conclusion, he relied on the MISO auction clearing results for Zone 6 (Indiana) for the past five years. Indiana Coal Council witness Hayet had a similar criticism of Vectren South's modeled capacity prices. He agreed that the cost of new entry ("CONE") served as the upper end of future capacity prices but that, also based on MISO historic auction clearing prices, it was inappropriate for future assumed capacity prices to approximate CONE. Instead, witness Hayet proposed to use 75% of CONE.

On rebuttal, Vectren South witness Joiner responded to Mr. Comings' testimony related to Vectren South's alleged overestimation of MISO capacity prices. Mr. Joiner testified he disagreed with Mr. Comings' contention that Vectren South should assume it will be able to purchase capacity and energy from the MISO market at low prices based upon recent market conditions. Mr. Joiner explained that the MISO market has been volatile in recent years and is experiencing shrinking

capacity, and such factors have prompted MISO to evaluate changes to its market structure. Mr. Joiner testified that MISO's recent and pending market reform initiatives, including MISO's Resource Availability and Need ("RAN"), are aimed at increasing capacity and energy prices to incentivize new generation development and are thus leading to higher prices as capacity tightens. As such, Mr. Joiner testified that while MISO's historical capacity and energy prices are indicators of recent trends, contrary to Mr. Comings' MISO auction clearing price testimony, they are not good indicators of expected, long-term future pricing. Moreover, the reported potential for a capacity shortfall by 2024 shows the risk of increased market prices.

F. Refueling Options. OUCC witness Boerger recommended that Vectren model a smaller 440 MW CCGT option in conjunction with gas refueling of one or both A.B. Brown units in order to consider a lower capital cost alternative. This option, which replaces retired coal units with a smaller gas baseload unit, was consistent with his stated concern that implementation of large quantities of intermittent renewables could create grid difficulties and that the extension of the life of small coal units is not common in the industry.

Mr. Lind's rebuttal presented the results of additional modeling in response to the OUCC's interest in further analysis related to resource plan options including coal-to-gas conversion that would make use of the A.B. Brown unit boilers. Burns & McDonnell performed that modeling and analyzed four additional portfolios, each where the conversion of one or more units to natural gas was considered. Mr. Lind testified that this updated rebuttal modeling used the more refined cost estimates (at the plus/minus 10% confidence level) for the CCGT for comparison with the coal-to-gas conversion portfolios (which were stated at plus/minus 50% accuracy.) Mr. Lind described the results of the updated analysis and testified that when compared with the coal-to-gas conversion portfolios, the preferred portfolio still produces a lower NPV and projected customer cost. Witness Games explained that this is due in part to the high heat rates of refueled units which result in very poor dispatch rates and resulting reliance on the market for energy needs. He explained that such a portfolio would result in customers significantly depending on market purchases for energy. Witness Games testified the fuel cost per MWhr from a converted gas plant is roughly $20 more expensive than the cost from the proposed CCGT when gas price is $4.000/dkt. He showed the much higher heat rates and lower capacity factors at converted plants that were completed between 2013 through the first quarter of 2018. Mr. Games testified during the hearing that the problem of high heat rates means that the refueled units continue to cycle and ramp up and down when dispatched, leading to wear and tear and the risk of additional maintenance costs.

G. Docket Entry Question & Response. As a follow-up to the additional modeling performed by Vectren South on rebuttal of gas conversion options, we issued a Docket Entry requesting further iterations of gas conversion portfolios. These included refurbishment of Broadway Unit 2 coupled with delays of removal of Warrick Unit 4 and installation of either a simple cycle or combined cycle gas turbine. Vectren South's response included the more refined cost estimate of the CCGT at plus/minus 10%, excluded additional environmental compliance costs at Warrick Unit 4 that would allow for the delay, and were presented with and without the commitment by Vectren South on rebuttal to pass 100% of wholesale revenues to customers if the CCGT is approved. All of the additional modeling requested by our docket entry produced a higher NPV than the lowest cost refueling portfolio presented on rebuttal (to convert A.B. Brown and instill a simple cycle gas turbine). With the sharing of 100% of wholesale revenues, all of the additional modeling produced a higher NPV when compared to the preferred portfolio ranging from 3.5% to 7.0%. Given that the preferred portfolio was within 4% of the lowest cost 2016 IRP portfolio (CCGT, an additional

simple cycle turbine, and delayed renewables), that means the gas conversion portfolios ranged anywhere from 8-12% higher than the lowest cost portfolio.

H. Estimated Cost of CCGT and RFP Process.

i. Vectren South. Mr. Games testified that, consistent with the 2016 IRP results, the 2017 IRP Update, and the Pace risk analysis, Vectren South is proposing to build a CCGT with 700 MW of baseload capacity and 150 MW of peaking capacity to replace retiring coal-fired capacity. Mr. Games testified Vectren South is proposing to build a unit with an output of approximately 850 MWs in order to hold some additional capacity to meet its obligations as a public utility, as well as to serve potential new customers and foster economic development. The 850 MW replaces 865 MW of retiring capacity (730 MW of baseload and 135 MW of peaking capacity, including Broadway Unit 2 in 2025). Mr. Games further testified the estimated cost of the CCGT is $781 million (+/-10%). The estimate includes owner's costs and allowance for funds used during construction ("AFUDC"). This figure was based on cost estimates developed by witness Diane M. Fischer, Central Regional Area Director and Associate Vice President with Black & Veatch. Those estimates were derived from a request for proposals for all equipment comprising the CCGT as well as construction. Mr. Games testified Vectren South is proposing to construct the new CCGT on its existing A.B. Brown generating site which will provide a conservative cost savings of $50 million resulting from reusing the existing site, facilities and equipment. He explained the critical timing of the in-service date of the CCGT which will be operational for the 2023/2024 MISO capacity year in order to retire the Culley 2 and A.B. Brown units and thereby avoid material capital investments otherwise required to operate those units beyond 2023. Similarly, the Warrick Unit 4 joint operating agreement will terminate at the end of 2023. To continue to operate Warrick would also require further investment to comply with environmental regulations.

Mr. Luttrell testified regarding the other replacement generation options Vectren South considered. He described the solicitation of competitive bids for either purchased power or ownership of all or a portion of a new CCGT unit. Mr. Luttrell explained Vectren South engaged Burns & McDonnell to manage the entire power supply RFP process, and testified this process allowed Vectren South to compare the best competitive offers for dispatchable baseload capacity to several self-build alternatives, including a partnership alternative. Mr. Luttrell testified that based on this economic and qualitative comparison, Vectren South made the decision to pursue building the duct-fired version of the proposed CCGT at the existing A.B. Brown site.

Mr. Lind testified in greater depth regarding Burns & McDonnell's role in developing and managing the RFP process to address Vectren South's power supply needs. He testified Vectren South received 11 unique proposals from six different developers. He further testified each of the conforming proposals was ranked and the top two proposals were compared with Vectren South's self-build proposals. Mr. Lind testified that based on NPV cost and qualitative risk factors, including a congestion analysis related to an off-system generation project developed by a third party, Vectren South determined that the self-build option was the best resource for reliable, long term service.

ii. OUCC. Witness Alvarez testified that, while Vectren South conducted an RFP, Vectren South did not competitively bid the actual CCGT it seeks to build in this case. OUCC witness Aguilar testified that Vectren South has not yet identified a manufacturer, chosen an exact type of CCGT, or issued any bids for the project.

iii. Coal Parties. ICC witness Medine criticized Vectren South's RFP process for a number of reasons, including the contention that Vectren South was involved in the process and the self-build project did not submit a bid as part of the RFP process. ICC witness Hayet stated a similar concern. Ms. Medine also disagreed with the position that self-build projects represent less risk than merchant projects. Ms. Medine further testified regarding the risks associated with self-builds, including cost over-runs. She testified that most if not all new Indiana plants have experienced cost over-runs that utilities look to customers to recover, and unless Vectren South is willing to guarantee costs, this is a risk that should be considered.

iv. Joint Intervenors. Witness Comings testified Vectren South did not facilitate a competitive bidding process, which limited resources and discouraged bidders from offering purchased power agreements ("PPAs"). He further testified the RFP should not have been limited to MISO Zone 6 and should have been similar to other investor-owned utility solicitations.

v. Vectren South Rebuttal. Mr. Luttrell responded to the Intervenors' criticisms of Vectren South's RFP process. With respect to Mr. Comings' criticisms that Vectren South did not facilitate a competitive bidding process, including limiting resources and discouraging bidders from offering PPAs, Mr. Luttrell testified Vectren South is retiring over 70% of its baseload capacity and the RFP was specifically designed to fill that deficiency with reliable cost-effective supply identified by the IRP. Mr. Luttrell further testified PPAs were not discouraged and all four of the responsive bidders offered a PPA. Mr. Luttrell also responded to Ms. Medine's criticisms that Vectren South was involved in many aspects of the solicitation and that Vectren South did not submit a bid as part of the RFP Process. Mr. Luttrell testified Vectren South used two separate teams—one focused on the RFP and evaluation and one focused on developing the cost estimate for the Vectren South-build CCGT—and each of these teams were separate and walled off from the other. He testified Vectren South's involvement in the RFP process was critical to help ensure the RFP would meet the needs its modeling indicated was necessary. He further testified he did not believe the RFP process was negatively impacted as a result of the self-build alternative being developed parallel to the evaluation of the RFP bids, and Ms. Medine acknowledges "there is no evidence that there was inappropriate information transfer." Mr. Luttrell explained that ultimately, an evaluation of congestion costs associated with the off-system resource proposal was the driver of selecting the CCGT project at A.B. Brown as the best option.

Mr. Luttrell also responded to Ms. Medine's position that a PPA does not pose a greater risk than having a regulated utility own the generation facility. Mr. Luttrell testified that Vectren South believes that an on-system project at an existing utility site subject to regulatory oversight and financed by a public utility, is less risky than relying on a developer. He further testified that when 70% of baseload capacity is at stake, a utility should consider all risks to project completion and to ongoing service in the long term. Mr. Luttrell provided a real-life, recent example of the risks associated with relying on a developer to construct a project. Further, Mr. Luttrell testified that a PPA does represent greater risk compared to a self-build option because the financing, construction, operation, and future financial stability of the seller is not in control of either the regulated public utility or the Commission. Mr. Lind also explained that while the cost estimate for the CCGT is stated at plus/minus 10%, the risk is actually higher (plus/minus 50%) for all portfolios that do not include the CCGT.

I. Construction of Gas Lateral to Serve CCGT.

i. Vectren South. Mr. Perry Pergola – Director, Gas Supply – testified regarding Vectren South's decision to secure the interstate pipeline services of Texas Gas Transmission ("TGT") to provide natural gas service to the proposed CCGT. He testified Vectren South selected TGT because it was the least cost pipeline option to serve the CCGT at the A.B. Brown location. Mr. Pergola further testified Vectren South will build and operate a new gas lateral to interconnect with TGT and serve the CCGT.

Mr. Steve Hoover – Director of Engineering – testified regarding the 23 mile gas lateral Vectren South will construct to connect the CCGT with TGT. He testified Vectren South will construct the pipeline itself because, by virtue of its experience building, operating and maintaining new or existing gas facilities in the Vectren South service area, Vectren South is uniquely qualified and positioned to construct the new pipeline. Mr. Hoover further testified the estimated cost to construct the gas pipeline is approximately $87 million. This is not included in the estimated cost of the CCGT as presented by witnesses Fischer and Games, as it is expected the costs of the gas pipeline will be reflected in the delivered cost of the gas.

ii. OUCC. OUCC witness Alvarez testified regarding Vectren South's proposal to build the gas lateral to serve the CCGT. He testified Vectren South did not include the costs necessary to build the gas lateral in the $781 million CCGT cost estimate and should have.

iii. Industrial Group. Industrial Group witness Gorman also testified regarding Vectren South's proposal to construct a gas lateral to serve the proposed CCGT. Mr. Gorman testified Vectren South's proposal to self-build the gas lateral is not consistent with protecting the public interest and is anti-competitive. He testified that Vectren South should have considered a third party or TGT to develop the gas lateral. Mr. Gorman testified that to the extent TGT can construct a gas lateral at a lower cost than the Vectren South self-build option, then this option should be adopted. Mr. Gorman further testified that Vectren South's proposal to recover the pipeline costs as part of the fuel costs for the CCGT is not reasonable because the fixed cost to build the gas lateral will not vary with energy generation or volume of gas delivered to the CCGT. He testified instead it would be appropriate to allocate the gas lateral cost as part of the CCGT fixed capital cost of the facility and allocate it on a capacity basis.

iv. Coal Parties. ICC witness Medine testified regarding Vectren South's proposal to construct the gas lateral. Ms. Medine characterized Vectren South's proposal as a proposal to build the lateral using an affiliate without competitive bidding. She also criticized Vectren South's decision to self-build the gas lateral instead of soliciting bids from third parties. Ms. Medine testified that Vectren South did not solicit bids for the lateral from third parties, and, therefore, it cannot represent that it was the lowest cost option for the construction of the lateral.

v. Vectren South Rebuttal. Vectren South witness Steve Hoover responded to criticisms raised by the Intervenors related to Vectren South's proposal to construct the gas lateral. Mr. Hoover testified that Ms. Medine's characterization of the proposal as an "affiliate transaction" has no bearing on the overall substance of the proposed transaction because there are many reasons why it is advantageous for Vectren South to construct the gas lateral. He reiterated that the Vectren South engineering, land services, and construction management teams have already

successfully completed two similar projects to deliver gas to Duke Edwardsport and IPL Eagle Valley generating units. He testified it is therefore in the best interest of Vectren South's customers for it to enlist the experience and expertise of its gas utility in the pipeline construction and operations. Mr. Hoover also responded to criticisms raised by witnesses Gorman and Medine that the lateral project is anti-competitive and being conducted without competitive bidding. Mr. Hoover testified that Vectren South requested TGT to provide a cost estimate to construct the lateral early in the process, and TGT's cost estimate was 10-15% higher than Vectren South's estimate. He further testified that Vectren South will complete a competitive procurement process to select a contractor to construct the lateral. Mr. Hoover testified that during the course of bidding and the evaluation process, Vectren South will also incorporate cost protections and performance incentives to ensure both competitive and fair pricing.

Mr. Hoover also responded to Mr. Gorman's preference that the lateral be placed in Vectren South's rate base as opposed to the costs being recovered via the Fuel Adjustment Clause ("FAC"). Mr. Hoover testified that like IPL and Duke, Vectren South has chosen to have a qualified local distribution company ("LDC") own and operate its gas delivery pipeline. Therefore, the pipeline will not be an electric utility asset and the costs associated with it will be recovered through gas rates.

As to the allegation that Vectren South's owning the gas pipeline as a gas utility asset is anti-competitive, witness Pergola testified on cross-examination that nearly all of the pipeline (more than 22 of the 23 miles of length) is located in Kentucky and therefore presents no opportunity for bypass, because Vectren South does not possess the right to serve customers in Kentucky.

J. Warrick Unit 4.

i. Vectren South. Mr. Wayne Games testified regarding the uncertain future of Warrick Unit 4. Mr. Games explained that Vectren South and Alcoa co-own the unit pursuant to a Joint Operating Agreement ("JOA") whereby each has 50% ownership in the unit. Mr. Games testified that while Warrick Unit 4 will continue to operate in the near term, the long term outlook for the unit is uncertain. He testified the future of the unit is tied to the Alcoa industrial site, and at any time Alcoa could decide to close the smelter unit, which utilizes significant quantities of electricity produced by Warrick Unit 4, based on price volatility in the aluminum market. He testified that the decision to shut down the smelter unit would jeopardize the future of Warrick Unit 4 and this uncertainty makes it difficult to justify investment in the unit or to depend upon it in the long run.

Vectren South witness Carl Chapman also testified regarding the future of Warrick Unit 4. Mr. Chapman testified that Vectren South has agreed to retain its involvement in the unit through 2023 to support the re-opening of the Alcoa smelter. However, he testified beyond 2023 it does not makes sense to continue to invest in a unit that could be subject to shut down if Alcoa decides it has no continuing need for the capacity.

ii. OUCC. OUCC witness Aguilar testified regarding Warrick Unit 4. Ms. Aguilar testified she does not agree with Vectren South's assessments of the risk of continuing to operate Warrick Unit 4 under the JOA and she disagrees with Vectren South's "presentation of the agreement." She further testified that Vectren South could continue to operate Warrick Unit 4 beyond 2023 with environmental compliance updates.

iii. Vectren South Rebuttal. Mr. Games responded to OUCC witness Aguilar's contention that Vectren South could continue to operate Warrick Unit 4 beyond 2023. He testified that due to compliance requirements coming in Alcoa's next National Pollutant Discharge Elimination System ("NPDES") permit, it is anticipated that the unit will require significant capital investment to meet environmental standards in the future. He testified that these investments coupled with the uncertainty related to whether Alcoa will continue to operate Warrick Unit 4[3] under the JOA and performance issues at the unit, warn against continued reliance on Warrick Unit 4.

Mr. Chapman also testified regarding the continued operation of Warrick Unit 4. He testified that the partnership with Alcoa jointly to operate Warrick Unit 4 has become highly uncertain in terms of duration and no longer represents a viable long-term resource option. Mr. Chapman further testified that while Vectren South's IRP recommended retirement of Warrick Unit 4 well before 2023, Vectren South examined each of the coal units to determine whether such units should be retained. He testified that while Culley 3 and Warrick Unit 4 had better profiles in terms of environmental equipment as compared to Vectren South's other units, Culley 3 ultimately had a better operating history based on cost, availability and heat rate. Mr. Chapman reiterated that a strike against continued operation of Warrick Unit 4 is the uncertainty surrounding the longevity of the Alcoa partnership. He reiterated the continued operation of Warrick Unit 4 is dependent on the aluminum market, and if Alcoa's industrial operations cease at the site, the environmental requirements facing Warrick Unit 4 will become significantly more stringent. Mr. Chapman ultimately testified the bottom line is assuming Warrick Unit 4 can continue on post-2023 presents great risk.

As noted previously, in response to our Docket Entry question seeking additional modeling of a portfolio with delayed retirement of Warrick Unit 4, Vectren South indicated that an additional capital investment cost of as much as $50 million may be required to retain the unit if IDEM determines not to renew a variance in the unit's current NPDES permit that allows water discharge at a higher temperature. The new draft renewal NPDES permit allows IDEM to terminate this variance at any time, which will likely require the construction of a cooling tower. Coupled with both Alcoa's and Vectren South's ability to terminate the joint operating agreement, this even further increases the risk of reliance on Warrick Unit 4 beyond 2023.

K. Culley Unit 3. While making investments to preserve some coal-fired generation is not part of the lowest NPV under the 2016 IRP modeling, Vectren South proposes to make investments at Culley Unit 3, its most efficient plant, in order that it may continue to operate beyond 2023. This decision became part of the preferred portfolio as a result of the risk assessment in the 2016 IRP. Preserving Culley Unit 3 promotes greater diversity in fuel sources and it also lessens the impact on the local coal industry. Witness Retherford described the environmental controls that are needed as a result of CCR and ELG. The Culley 3 Compliance Projects consist of (1) conversion of the current wet bottom ash collection system to a dry handling bottom ash system; (2) installation of a spray dryer evaporator system; and (3) the closure of the Culley West ash pond and construction of a new lined process water and storm water retention pond in its place. This new retention pond will be constructed on the location of the existing ash pond due to space limitations. Witness Fischer developed the cost estimates for the former two and Ms. Retherford provided the cost estimate for the latter. Recovery of the associated costs through a rate adjustment mechanism under Ind. Code ch. 8-1-8.4 was opposed by OUCC witness Aguilar and Industrial Group witness Gorman.

[3] With proper notice, Alcoa can also terminate the JOA.

4. Pending Summary Judgment Motion and Motion to Dismiss under T.R. 41(B). On July 19, 2018, the Coal Parties, Joint Intervenors, Evansville Western Railway, the OUCC, and the Industrial Group filed a Motion for Summary Judgment asking the Commission to vacate the schedule, arguing that we cannot grant Vectren South's request for authority to construct facilities until we have completed a "final" statewide analysis pursuant to Ind. Code § 8-1-8.5-3(a). Alternatively, the Movants asked us to grant them an extension of time to file their pre-filed testimony until at least 45 days after we post a "final" statewide analysis. We took the matter under advisement. At the conclusion of Vectren South's case-in-chief, Alliance Coal made an oral motion to dismiss under T.R. 41(B) on the same grounds. The T.R. 41(B) motion was joined by the OUCC and all of the other Movants except the Industrial Group and Evansville Railway.

In construing a statute, we start with its plain language and "attempt[] to give words their plain and ordinary meanings." *Indiana Wholesale Wine & Liquor Co., Inc. v. State ex rel. Indiana Alcoholic Beverage Com'n*, 695 N.E.2d 99, 103 (Ind., 1998) (citations omitted). "[I]n seeking to give effect to the legislature's intent, [the court] read[s] an act's sections as a whole and strive[s] to give effect to all of the provisions so that no part is held meaningless if it can be reconciled with the rest of the statute." *Fort Wayne Patrolmen's Benev. Ass'n, Inc. v. City of Fort Wayne*, 903 N.E.2d 493, 497 (Ind. Ct. App., 2009) (citation omitted).

The Motion is based primarily on Section 3(a) of Ind. Code § 8-1-8.5, which provides that "[t]he Commission shall develop, publicize, and keep current an analysis of the long range needs for expansion of facilities for generation of electricity," and Section 3(c), which provides that "[t]he commission shall consider the analysis in acting upon any petition by any utility for consideration." The Movants interpret these provisions to mean that we cannot consider a certificate of public convenience and necessity ("CPCN") request absent a "final" statewide analysis. We disagree.

Neither provision requires or implies there must be a "final" or conclusive statewide analysis. Nor does any other provision in Chapter 8.5. Section 3 directs us to undertake an "analysis" that is subject to ongoing review and revision. An analysis that must remain "current" cannot possibly remain static or culminate in a finished product. We find that the analysis detailed in the draft and final versions of the Statewide Analysis meets the requirements of the statute.

To the extent the Movants argue that we cannot grant Vectren South's Petition until we complete our annual report on the analysis, their Motion also fails.

Section 3(h) requires us "[e]ach year" to "submit to the governor and to the appropriate committees of the general assembly a report of its analysis regarding the future requirements of electricity for Indiana or this region." Ind. Code § 8-1-8.5-3(h). Section 5(b)(2) provides that a certificate may be granted if the Commission finds the project (A) "will be consistent with the Commission's analysis (or such part of the analysis as may then be developed, if any)"; or (B) is "consistent with a utility's specific proposal submitted under Section 3(e)(1) of this chapter and approved under subsection (d)." Ind. Code § 8-1-8.5-5(b)(2)(A) and (B).

This unambiguous language reflects the Legislature's understanding that new generation needs may arise at a time while the analysis or even the annual report is being developed or under revision. The Legislature granted the Commission authority to issue a CPCN rather than hold the request in abeyance until the annual report is issued.

It must be presumed that "'the legislature intended the language used in the statute be applied logically and not to bring about an unjust or absurd result.'" *D.B. v. Review Bd. of Indiana Dept. of Workforce Development*, 2 N.E.3d 705, 710 (Ind. Ct. App., 2013) (quoting *Penny v. Review Bd. of Ind. Dep't of Workforce Dev.*, 852 N.E.2d 954, 960 (Ind. Ct. App., 2006), trans. denied). Reviewing bodies also avoid "interpreting a statute in such a manner as to render its provisions mere surplusage." *Id.* (citing *In re Adoption of D.C.*, 887 N.E.2d 950, 959 (Ind. Ct. App., 2008). The Legislature cannot have meant for the Commission to hold off assessing petitions until its analysis becomes "final" (which will never occur), or even until its annual report is submitted. Thus, the statute is clear that in considering a CPCN request, pursuant to Section 5(b)(2) we can rely on whatever current statewide analysis exists or simply determine whether the proposal is consistent with the utility's own plan and reports.

In sum, the Commission retains authority to review a project at any time. Ind. Code § 8-1-8.5-5.5 expressly allows us to "commence a review of any certificate granted under this chapter" when, "in the opinion of the commission, changes in the estimate of the probable future growth of the use of electricity" call for such review. Further, "[i]f the commission finds that completion of the facility under construction is no longer in the public interest, the commission may modify or revoke the certificate." Id.

For all of the foregoing reasons, and each of them, the Motions for Summary Judgment and for Dismissal under T.R. 41(B) are denied.

5. Commission Discussion and Findings.

A. Vectren South's Request for a CPCN for a CCGT. Vectren South requests a CPCN for a proposed CCGT (approximately 850 MW) to be constructed at the current site of the A.B. Brown power plant in Posey County. Under Chapter 8.5, a public utility may not begin the construction, purchase or lease of any steam, water, or other facility for the generation of electricity to be directly or indirectly used for the furnishing of public utility service without first obtaining from the Commission a certificate that public convenience and necessity requires, or will require, such construction, purchase or lease.

In considering a CPCN request, Chapter 8.5 requires the Commission to consider options other than the construction, purchase, or lease of an electric generating facility. *See* Ind. Code § 8-1-8.5-4.

Further, Ind. Code § 8-1-8.5-5 sets forth specific findings the Commission must make in order to approve and grant the requested CPCN. First, the Commission must make a finding, based on the evidence of the record, as to the best estimate of construction costs. Second, the Commission must find that either (a) construction will be consistent with the Commission's Statewide Analysis, if any, for the expansion of electric generation facilities, or (b) the proposed construction is consistent with a utility-specific proposal as to the future needs of consumers in the State of Indiana or in the petitioning public utility's service area [i.e., the utility's IRP]. Third, the Commission must find that public convenience and necessity require the facilities for which the CPCN is requested.[4]

[4] A fourth finding relating to coal-consuming facilities, pursuant to Ind. Code § 8-1-8.5-5(b)(4), does not apply to the proposed natural gas facilities.

"We have indicated in previous CPCN cases that 'least-cost planning' is an essential component of our [CPCN] law." *Joint Petition of PSI Energy, Inc. and CINCAP VII, LLC*, Cause No. 42145, at 4 (IURC Dec. 29, 2002), *quoting Southern Indiana Gas & Electric Co.*, Cause No. 38738, at 5 (IURC Oct. 25, 1989). "We have defined 'least-cost planning' as a 'planning approach' which will find the set of options most likely to provide utility services at the lowest cost once appropriate service and reliability levels are determined." *Id.* "However, we have emphasized that the [CPCN] statute does not require the utility to automatically select the least cost alternative. Nor does the statute require the utility to ignore its obligation to provide reliable service or to disregard its exercise of reasonable judgment as to how best to meet its obligation to serve." *Id.* As this Commission has previously ruled: "[i]f an Indiana utility reasonably considers and evaluates the statutorily required options for providing reliable, efficient, and economic service, then the utility should, in recognition that it bears the service obligations of IC 8-1-2-4, be given some discretion to exercise its reasonable judgment in selecting the option or options to implement which minimize the cost of providing such service." *PSI Energy, Inc.*, Cause No. 39175, at 14 (IURC May 13, 1992); *see also Joint Petition of PSI Energy, Inc. and CINCAP VII, LLC*, Cause No. 42145, at 4.

The pre-approval of long-lived power plant investment and the concurrent regulatory assurance of that investment's recovery is, at its base, the creation of fixed costs that customers will be required to pay several years into the future, perhaps as long as 30 years or more into the future. Accordingly, our consideration in this and other pre-approval requests, especially in periods of seemingly quickening technological change, must not ignore the risk that any such investment may become uneconomic over the long-term. We must acknowledge that the economic forces at work may come from other supply side options or even demand side opportunities. The supply side and demand side certificating statutes implicate this by recognizing that an optimal balance of energy resources should consider both aspects in meeting customer needs.[5] A complication in the optimizing effort is the often disparate time horizons of the supply and demand sides of the balance. The inability to adjust the long-lasting nature of the supply side of the equation in the event market conditions or demand side expectations change in a lesser time horizon introduces a risk that some measure of the supply side investment may become uneconomic within its lifetime.[6] Demand side efforts by customers as a result of the uncontroverted improving economics of customer-scale generation resources may further compound the challenge of the optimal balancing act. Reducing demand in the near term does not necessarily correspond with reduced assured supply side investment cost recovery.[7] Because unwinding assured cost recovery should an asset become uneconomic is not a commonly employed regulatory option, it is prudent to ensure during the pre-approval process that we understand and consider the risk that customers could sometime in the future be saddled with an uneconomic investment. Outcomes that reasonably minimize such potential risk and serve to foster utility and customer flexibility in an environment of rapid technological innovation on both the utility and customer side of the meter are, therefore, a lens through which we will review Vectren South's request.

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[5] Indiana Code §§ 8-1-8.5-4 and -10(c)(3).

[6] This effect can be see through the recovery of lost revenues a statutory component of utility DSM programs, which is in part a function of investment, of fixed cost, that is not being consumed at the expected rate.

[7] This timing inconsistency can reduce the value of demand side efforts because they are not avoiding long-lived fixed costs previously approved and included in rates. The full incremental impacts of demand side actions which occur after the approval of long-lived fixed costs are only affected over longer periods of time when future resources must be acquired and the timing and type of resource might change as a result of cumulative demand side activities.

i. Ind. Code §§ 8-1-8.5-4.

(1) Ind. Code § 8-1-8.5-4(1). In evaluating a utility application for approval to construct new generation, the Legislature has directed us to take into account the utility's "current and potential arrangements with other electric utilities for (A) the interchange of power; (B) the pooling of facilities; (C) the purchase of power; and (D) joint ownership of facilities."

As a member of MISO, Vectren South interchanges power on a daily basis, and Vectren South's modeling considered and factored this arrangement into its decision to seek a CPCN. In addition, early in its resource selection process Vectren South identified a potential partner for a joint generation project. Witness Luttrell explained that this partner was interested in owning a minority share of a larger CCGT, and agreed to study locating such a unit on Vectren South's system. As studies ensued, the partnership appeared to be a viable resource option. As a result, the parties studied this joint ownership opportunity throughout 2017, but ultimately in January 2018 the potential partner provided notice that it would not proceed with such a project. Both Vectren South and the Commission have considered the interchange of power and pooling of facilities.

When assessing a CPCN petition, the Commission also considers the potential purchase of power by Vectren South. On June 20, 2017, Vectren South issued a RFP for dispatchable resources located in MISO Zone 6. Vectren South explained that its RFP specified this location requirement in order to satisfy MISO's requirement that a load serving entity have at least 67% of its resources located within its zone. The RFP sought dispatchable resources based upon the 2016 IRP analysis, which recommended that Vectren South retire nearly all of its baseload coal-fired capacity by the end of 2023. As a result, the RFP was designed to solicit baseload capacity to replace the 730 MWs provided by the retiring coal units. In response, Vectren South received nine qualified bids offering both PPAs and offers to build a CCGT and sell that unit or a partial interest in that unit to Vectren South. Using the expertise of Burns & McDonnell ("BMC"), Vectren South evaluated both quantitative and qualitative aspects of the competing bids. Based on BMC's analysis of the levelized cost of energy ("LCOE") of the bids, Vectren South selected the bid with the most favorable LCOE to compare to a self-build option. BMC's analysis was that Vectren South's self-build option had a better net present value than this best bid, and also exposed Vectren South to less risk versus long-term reliance on a merchant developer. Vectren South's rebuttal testimony noted that the merchant developer in question had in fact, even prior to its bid submission, withdrawn its project from the MISO queue without informing Vectren South.

The Commission acknowledges Vectren South's issuance of an RFP but believes the RFP was unduly restrictive given the rapid changes in technology and costs being seen in the market, especially regarding renewable energy. The narrow RFP with its focus on a large baseload dispatchable resource limited the options Vectren South evaluated to those larger than 600 MW. As a result, Vectren South foreclosed consideration of combinations of smaller resources that might have offered greater resource diversity, flexibility and cost efficiencies than reliance on the acquisition of a single large natural-gas facility. As discussed further below, expansion of the RFP to consider a broader spectrum of resource options would have also gone a long way to improve the metrics to limit risks from exposure to changes in market conditions and technologies.

Based on Vectren South's unduly restrictive RFP the Commission cannot conclude that Vectren South thoroughly evaluated the purchase of power in connection with Vectren South's request.

(2). Ind. Code § 8-1-8.5-4(2).

(a) The Refurbishment of Existing Facilities. In acting upon a petition for the construction of an electric generation facility, we must consider other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities. Ind. Code § 8-1-8.5-4(2). Ms. Aguilar summarized the following alternatives that Vectren South failed to fully analyze: (1) Retain Coal at Vectren South's existing plants and invest in refurbishments; (2) Retain the agreement with Alcoa for Warrick Unit 4; (3) Refuel the A.B. Brown unit(s) with gas; (4) A blended option, such as refueling one or more A.B. Brown units to gas and building a smaller CCGT; (5) Enter into a PPA with one of the bidders who responded to Vectren South's RFP; and (6) Retain its Broadway Avenue Unit 2. Pub. Ex 1, p. 8. Ms. Aguilar argued that Vectren South unfairly screened out these alternatives during the IRP process.

We agree with Ms. Aguilar and Dr. Boerger that Vectren South did not fully consider options to extend the life, or refurbish, existing units as required by Ind. Code § 8-1-8.5-4(1). *Id.* and Pub. Ex. 3, p. 6. This failure began during Vectren South's IRP process, when Vectren South screened out, without further study, viable refurbishment options. Pub. Ex. 1, p. 11. Vectren South's stated reason for shutting down the A.B. Brown units is premised on the need to replace the flue-gas desulfurization ("FGD") units at a cost of approximately $350 million. Pub. Ex. 3, p. 7. Dr. Boerger stated that with the exception of the current FGDs, the units operate quite well and are sized appropriately for a small utility like Vectren South. But as noted by Ms. Aguilar and Dr. Boerger, Vectren South's chosen FGD replacement technology was the most expensive and only technology reviewed. *Id.,* Pub. Ex. 3. Dr. Boerger pointed out that Vectren South did not consider lower-cost FGD replacement options, even though such options were available. He said that this decision made the continued use of the A.B. Brown units look less attractive in modeling than if those options had been included. A reasonable alternative would have been the refurbishment of these units through refueling. Pub. Ex. 3, p. 7. Refueling is viable, proven technology that could be accomplished at a fraction of the price of the CCGT – approximately $45 million for both A.B. Brown units.

Vectren South considered a smaller 440 MW CCGT option in its last IRP, but Vectren South did not include it as part of any refueling options. Pub. Ex. 3, p. 9. Further, when Vectren South issued its RFP, it did so for 600-800 MW of dispatchable power, precluding smaller units that might have combined with refurbishment of other Vectren South units. Tr. B-25 - B-26. Vectren South did not fully model the conversion of one of the A.B. Brown units in its rebuttal testimony. Tr. E-45 – E-46.

On cross-examination, Vectren South witness Mr. Swiz estimated that the value of the stranded assets at the A.B. Brown unit alone will equal $220 million and that the system-wide total will be $270 million. While Vectren South argues that the CCGT option is the lowest cost, we find for the many reasons stated throughout this Order, including Vectren South's failure to sufficiently consider the refurbishment and continued operation of its existing facilities, we are not able to verify this claim. Through the lens of minimizing risk and providing future flexibility the refurbishment option would seem to provide a potential bridge to the future, providing system capacity value that was not sufficiently evaluated. This conservative solution and risk avoidance strategy stands in stark contrast to proposed CCGT. Vectren South plans to submit a new IRP in 2019. We instruct Vectren South to closely consider our analysis in this Order and the Director's Report on the 2016 IRP of the flaws in their modeling for the 2016 IRP and the 2017 IRP Update and to present a more thorough

analysis that fully evaluates all possible options for continuing to provide reliable, efficient, and economical electric service.

(b) Conservation and Load Management. The evidence demonstrates that Vectren South has evaluated the CCGT against other reasonable generation alternatives, and included demand side management and energy efficiency ("DSM/EE") levels consistent with the targets approved in Cause No. 44927. Vectren South's modeling concludes that, even when the cost of energy efficiency has been significantly lowered, the CCGT is still the least cost reliable resource alternative to meet Vectren South's customers' future energy resource needs.

The Joint Intervenors criticize the assumptions used by Vectren South to model the cost of DSM/EE, arguing that the assumptions used by Vectren South were too high resulting in a higher cost of DSM/EE. Ms. Harris stated in her rebuttal that for purposes of this proceeding, Vectren South opted only to update its growth factors in its revised cost analysis in order to show the impact lower DSM/EE costs would have on the energy resources selected in its IRP. Ms. Harris explained that limiting the updates to the growth factors preserved the integrity of Vectren South's 2016 IRP. Petitioner's Exhibit No. 8-R, p. 3. We find that while some of the cost assumptions used by Vectren South could have been updated, on the whole it does not render Vectren South's analysis of DSM/EE unreasonable.

(c) Cogeneration and Renewable Energy Sources. Vectren South's IRP modeling process considered the potential for cogeneration facilities to serve its customers and adjusted its load forecast to reflect the potential for cogeneration facilities. Petitioner's Exhibit No. 5, Attachment MAR-1, pp. 99-103. Consequently, the potential for customer-owned generation resources, including renewable generation, to reduce Vectren South's load was evaluated as part of the IRP process that concluded the CCGT was necessary as part of least-cost planning. Nonetheless, while Vectren South may have considered renewable energy in the IRP, there is a lack of evidence that Vectren South made a serious effort to determine the price and availability of renewables. In addition, the economics of customer-scale renewable and cogeneration facilities appears likely to continue to improve and we anticipate that additional well-developed efforts to understand their customers' interest would serve to provide clarity to the lens of risk avoidance by minimizing the potential for unexpected demand side efforts. Therefore, we would expect Vectren South to ensure an enhanced consideration of renewable energy and customer-generator opportunities in future IRPs.

(3) Ind. Code § 8-1-8.5-5. A certificate may be granted only if the Commission makes the followings findings:

(a) Best estimate of construction, purchase, or lease costs based on the evidence of record. The cost estimates for Vectren South's proposed CCGT were developed and presented by witness Diane Fischer. Black & Veatch developed a design basis and conceptual design and thereafter developed a cost estimate. Several conceptual designs were first developed. From that, ten plant alternatives for purposes of estimating costs were identified. This was later narrowed to seven alternatives for which detailed costs were developed. Competitive bids were obtained for the equipment and materials. Based upon Black & Veatch's experience as an engineering, procurement and construction ("EPC") contractor, Black & Veatch was able to estimate indirect costs, contingency, overhead, and profit for the EPC contractor. Bids were also received for construction. Ultimately, Ms. Fischer testified that the cost estimate for the proposed CCGT had been refined to +/- 10%. The total estimated project cost (excluding owner's costs) was $582,000,000. The owner's

costs were then provided by witness Games, including insurance, contingency, study, and AFUDC. The total cost estimate was $781,000,000.

(b) Consistency of the CCGT with Vectren South's Utility-Specific IRP and the Statewide Analysis. Ind. Code § 8-1-8.5-5(b)(2)(A) directs the Commission to determine whether Vectren South's proposed construction of a new CCGT will be consistent with the Commission's 2018 Statewide Analysis. The final version of that report was issued after the parties' pre-filing deadline, but before the evidentiary hearing and was admitted into evidence as Pet. Admin. Not. Ex. 2. Included in that report is a synopsis of information taken from the most recent IRP projects of Indiana utilities, including Vectren South.

In Appendix 12 of the Statewide Analysis, the concept of Resource Diversity is explained:

> In an electric system, resource diversity may be characterized as utilizing multiple resource types to meet demand. A more diversified system is intuitively expected to have increased flexibility and adaptability to: 1) mitigate risk associated with equipment design issues or common modes of failure in similar resource types, 2) address fuel price volatility, and 3) reliably mitigate instabilities caused by weather and other unforeseen system shocks. In this way, resource diversity can be considered a system-wide tool to ensure a stable and reliable supply of electricity. Resource diversity itself, however, is not a measure of reliability. Relying too heavily on any one fuel type may create a fuel security or resilience issue because the level of resource mix diversity does not correlate directly with a resource portfolio's ability to provide sufficient generator reliability attributes.

Vectren South's proposal to concentrate its base load capacity from five different generating units located at three different sites down to just three generating units (one of them constituting 70% of Vectren South's baseload capacity) located at two sites appears to be contrary to the concept of resource diversity.

On page 5 of the 2018 Statewide Analysis it says:

> A key consideration in long-term resource planning is the need to retain maximum flexibility in utility resource decisions to minimize risks. An IRP developed by a utility should be regarded as illustrative and not a commitment for the utility to undertake.

In explaining the importance of sound long-range planning on page 56 of the 2018 Statewide Analysis, it says, "[t]he credibility of the analysis is critical to the efforts of Indiana utilities to maintain as many options as possible, which includes off ramps, to react quickly to changing circumstances and make appropriate changes in the resources." However, we find nothing in Vectren South's evidence convinces us that its proposal provides any off ramps that would allow Vectren South to react to changing circumstances and make appropriate changes in resources. To the contrary, Vectren South's proposal seems to close most off ramps for the foreseeable future.

The parties offered diametrically opposed views on the modeling offered to support the CPCN, with Vectren South pointing to its CCGT conclusion as consistent with its IRP. But that conclusion is but one part of the analysis. We have criticized utilities in the past for modeling infirmities and even penalized a utility for analysis we found lacking. In IPL's MATS case, we ordered a $10 million credit to customers to "send[] an appropriate message" to the utility. *Indianapolis Pwr. & Light Co.*, Cause No. 44242, 2013 WL 4479081 *38, 307 P.U.R.4th 311, Order p. 36 (IURC Aug. 14, 2013). We found IPL's cost/benefit study "disappointing" and noted our own "responsibility to insure that the regulatory process involves the presentation of the best evidence possible, given the facts and circumstances of a particular case." *Id.* at 35.

At the outset, Mr. Games testified that Vectren South sent a request for information ("RFI") to original equipment manufacturers ("OEM") for CCGT pricing information before Vectren South's 2016 IRP. Tr. E-89 – E-91. Mr. Chapman stated that under any of the IRP models, the CCGT is the least expensive. Tr. A-27 - A-28.

Dr. Boerger testified that Vectren South did not consider other viable options such as refueling and smaller combinations of generation assets to meet its needs, Pub. Ex. 3, p. 1 – p. 2, which would be more prudent for a small utility like Vectren South. Pub. Ex. 3, p. 5. Vectren South excluded possible options such as maintaining Culley 2, Pub. Ex. 3, pp. 11-12, and did not allow the refueling of the A.B. Brown units to be included in any of its model runs. *Id.* Vectren South kept a smaller, 440 MW CCGT from being combined with a refueled A.B. Brown unit. Pub. Ex. 3, p. 13. Mr. Games admitted that Vectren "never [ran] a risk analysis of portfolios including a 1 X 1 CCGT instead of a 2 X 1[.]" Tr. E-50. Vectren South also did not allow for proposals of joint projects to be built at it's A.B. Brown site, which would eliminate the potential for congestion problems Vectren South identified as a problem in its RFP responses. Vectren South's Strategist model limited the amount of capacity purchases that a given portfolio could make. Tr. D-73. This had the effect of automatically screening out PPAs that could have been combined with other resources to meet Vectren South's capacity needs. The Director's Report on Vectren South's 2016 IRP noted that Vectren South failed to model a wide range of gas prices, making the "range of fuel price projections… unduly limited[,]" Tr. D-85, and Vectren South's re-run of gas costs did not model higher prices in a wide enough range. Tr. D-86. As noted by Mr. Alvarez, Vectren South's model retired the BAGS 2 unit in 2024 without evidence of any engineering reason to do so. Pub. Ex. 2, pp. 13-14.

Dr. Boerger also found that Vectren South modeled the cost of its proposed CCGT to be $200 million less than the cost of the project presented in the testimony of Vectren South witness Games. Pub. Ex. 3, p. 2. The consequence of excluding $200 million in Vectren South's NPV calculation had the effect of making the CCGT option look more favorable. Pub. Ex. 3, p. 14. Without adding the $200 million back into the model runs, Vectren South's analysis is skewed. Pub. Ex. 3, p. 18 – p. 19. Mr. Games admitted that his testimony about the estimates was confusing, stating "[w]e started off with 2017 dollars, and those were -- then overheads were added, anticipated profit with the EPC, contingency for EPC, and escalation was added to get to the 582 million." Tr. E-15 – E-16. Mr. Lind took issue with Dr. Boerger's analysis, but admitted that Vectren South did not include $130 million in owner's costs when it compared its self-built CCGT to other options offered in the RFP and otherwise. Tr. A-36 – A-38; Tr. D-7 – D-8. When questioned why BMC did not use the $781 million figure, Mr. Lind stated that the $630 million estimate used for modeling was a +/- 50% estimate; the $781 million had a more certain +/- 10% range of accuracy. Tr. A-35; Tr. C-61 - C-62, C-74. BMC's projected cost of $580 - $650 million was used to weigh the economics of potential projects. Tr. A-

36 – A-38. And Vectren South witness Mr. Vicinus ran his "low regulatory" model using the $630 million estimate. Tr. D-98.

In response to the OUCC's criticism of its modeling, Vectren South's rebuttal included a new model run that refueled one of the A.B. Brown units, and added 200 MW of solar. Tr. D-12 – D-13. Vectren South used this rebuttal modeling to try to reinforce its original request for a 850 MW CCGT. Both Mr. Lind and Mr. Games acknowledged, however, that the addition of 200 MW of solar was not the best choice to meet MISO's PRM, because MISO would only give Vectren 100 MW of credit for the 200 MW of solar. Tr. E-15. The revised model also did not take into account the fact that solar costs between $1,200 - $1,800 per MW, Tr. D-16 – D-17, and Vectren South did not model any storage to counter the inherent intermittency of solar resources. Tr. D-14.

While we find Vectren South's request is "consistent" with its 2016 IRP, the subsequent modeling for this case effectively screened out multiple less-expensive alternatives. Vectren South did not allow its models to choose refueling or smaller units in combination. While Vectren South's rebuttal modeling runs included refueling of the A.B. Brown units in various configurations, the rebuttal modeling was not used to make Vectren South's decision of what generation form to choose. Tr. D-14. We view the rebuttal modeling as an after-thought used to buttress Vectren South's initial request.

Vectren South had sufficient time to conduct its analysis in a way more open to smaller-scale options that would correct the modeling deficiencies that have been identified. It seems straight-forward to suggest that smaller-scale options, especially for a relatively small electric utility, serve to minimize the risk should a challenge arise at any one option. As noted above, minimizing supply side long-term investment risk in an environment of rapid technological innovation is an attractive characteristic in a utility resource proposal. Vectren South should use its scheduled 2019 IRP process to address problems in its modeling, incorporate more options for partnering with other entities and competitive inquiries into smaller-scale options that can be acted upon swiftly to meet the end-of-2023 date upon which additional capacity may be needed.

(c) Public Convenience and Necessity. Ind. Code § 8-1-8.5-5(b)(2) requires that we find that public convenience and necessity requires or will require the proposed CCGT. Such consideration of the public interest is not only a statutory requirement at the outset but would become a continuing obligation should the Commission grant a CPCN. Ind. Code § 8-1-8.5-5.5 provides that if, after granting a CPCN for construction of a new generator, "the commission finds that completion of the facility under construction is no longer in the public interest, the commission may modify or revoke the certificate."

"[P]ublic interest may be taken to encompass a wide range of considerations, from environmental, health, and safety concerns, to the financial concerns of employers, employees, and ratepayers." *General Motors Corp. v. Indianapolis Power & Light Co.*, 654 N.E.2d 752, 762 (Ind. Ct. App., 1995). In *General Motors*, the court approved the Commission's consideration of the impact on employment in the coal industry in its public interest determination. *Id.*

The parties dispute whether Vectren South accurately and adequately evaluated risk in its analysis of alternative portfolios and selection of the proposed CCGT. As noted earlier, under Ind. Code § 8-1-8.5-4, we are required to take into account other methods for providing reliable, efficient,

and economical service, and we find utility risk analyses play an important role in comparing alternative portfolios.

Joint Intervenors argued that Vectren South's risk analysis is inadequate for multiple reasons. Joint Intervenors note that the risk analysis has not been updated since the 2016 IRP, despite Vectren South having updated inputs available for several inputs, including the estimated cost of its preferred build, and adequate time to re-run the model. Joint Intervenors complain that Vectren South ignored known material risks in a manner that biased results in favor of its preferred portfolio, including taking a one-sided view of capacity purchase and market purchase risks and failing to consider the potential for future methane regulations. Joint Intervenors further argue that Vectren South arbitrarily scored several metrics and designed others to conceal rather than measure obvious risks of the preferred portfolio.

We find merit in several of Joint Intervenor's critiques and are further concerned that Vectren South has not fully responded to critiques in the Final Director's Report on the 2016 IRPs. We agree that Vectren South had adequate time and opportunity to update its risk analysis modeling prior to this filing, and that it has sufficient time to do so now before moving forward. Vectren South updated inputs in its possession for multiple factors, including: solar capital costs; variable production costs and revenue requirement assumptions for existing units; forecasted cost for wholesale market capacity and energy; delivered fuel prices for gas and coal; and costs associated with new energy efficiency programs. Pet. Ex. 6 at 9-10. Vectren South also had a higher capital cost estimate for its preferred build. We know Vectren South had time to use these inputs to re-run the model because (a) it did just that with some of its Strategist modeling and (b) Mr. Vicinus testified that it would have taken just three months to re-run the risk analysis modeling. Tr. p. D-66. Mr. Vicinus opined that updated risk modeling would not change the result, but we are skeptical given the number and import of the updated inputs and the significance of the proposed portfolio changes. *See Indianapolis Pwr. & Light,* Cause No. 44339, 2014 WL 2091348, Order p. 27 (IURC May 14, 2014) ("[W]e believe that IPL could have reasonably updated the [model] given the extent of changes in data inputs and assumptions and provided a more robust analysis."). Before proposing a portfolio change of this magnitude, Vectren South should have taken the three months necessary to update its risk analysis modeling. Updated risk modeling may not be necessary in all cases, but it is warranted here given the size and cost of the proposed CCGT.

We are further concerned that Vectren South appears not to have accounted for material risks associated with its preferred portfolio. As we have previously stated, "it is appropriate that modeling take into consideration reasonable risks and unknowns." *Indianapolis Pwr. & Light Co.*, Cause No. 44794, 2017 WL 1632316, Order p. 28 (IURC Apr. 26, 2017). Joint Intervenors point out that Vectren South's risk analysis took a one-sided view of capacity purchase and market purchase risks. *See* JI Ex. 2 at 43; Vicinus Rebuttal. Vectren South offered no rebuttal explaining its one-sided view of market risk, which assumed surplus capacity and generation offers only benefits to ratepayers. JI Ex. 2 at 20-21. That view of market purchases is only true when market prices and/or load are high. JI Ex. 2 at 21. Further, Vectren South's Docket Entry response of October 5, 2018, presents portfolio results that suggest the material weight at which opportunity sales influences the analysis.[8] Heavy dependence on market revenues to support a regulated investment choice is a speculative influence that we find must be materially discounted to limit the risk of customers being saddled with

[8] The submitted table indicates that the advantage of the Preferred Portfolio in comparison to (1) BAU to Gas Conversion escalates from 1.3% to 3.5% when the opportunity sales sharing moves from 50% to 100%.

uneconomic options should such speculation unfold differently than forecasted. A metric biased in favor of portfolios with surplus generation is speculation we decline to embrace.

Vectren South's own witnesses and others acknowledged risks related to relying on gas generation, but Vectren South only considered carbon dioxide emission reductions when it evaluated environmental risk. We agree that was too narrow an approach to environmental risk and one that biased the analysis in favor of gas-fired generation.

The Commission appreciates the metrics developed and used by Vectren South in the 2016 IRP, but we agree with the Joint Intervenors that the use of these particular metrics also obscured critical characteristics of the preferred portfolio. One of Vectren South's IRP objectives was to develop a plan with flexibility to adapt to market conditions and technological change to minimize risks to shareholders and customers. Specific metrics to measure resource portfolio balance and flexibility included concentration on one technology, the number of technologies and having resources remote from Vectren South's load. A critical piece of information these metrics overlook is that the acquisition of an 850 MW resource must be evaluated relative to the load to be served. Vectren South's 2016 IRP Base peak load forecast is for the summer peak to increase from 1,109 MW in 2019 to 1,198 MW in 2036. The acquisition of an 850 MW generation facility represents approximately 77 percent of the 2019 peak load and just under 71 percent of the summer peak load for 2036. We are hard pressed to see how reliance on one facility for so much of the Vectren South system requirements is consistent with maintaining flexibility to respond to changing market conditions and technological change.

Therefore, we conclude that Vectren South's risk analysis does not adequately consider the relative risk of other methods for providing reliable, efficient, and economical electric service. The proposed large scale single resource investment for a utility of Vectren South's size does not present an outcome which reasonably minimizes the potential risk that customers could sometime in the future be saddled with an uneconomic investment or serve to foster utility and customer flexibility in an environment of rapid technological innovation. As a result, we find that Vectren South has not demonstrated through the evidence of record that the public convenience and necessity require the building of an 850 MW CCGT. Therefore, Vectren South's request for a CPCN to construct a 850 MW CCGT is denied.

B. Vectren South's Request for a CPCN for Culley compliance projects and related relief. Vectren South's preferred portfolio also includes the construction of various environmental projects that Vectren South contends are needed so that Culley Unit 3 can continue to operate beyond 2023. Vectren South's petition seeks relief for these projects under Ind. Code ch. 8-1-8.4 as "federally mandated" projects.

i. Ind. Code ch. § 8-1-8.4 ("Chapter 8.4").

(1) Federally Mandated Requirements (Ind. Code §§ 8-1-8.4-5 and 8-1-8.4-6(b)(1)(A) and 8-1-8.4-7(b)(3)). Ind. Code § 8-1-8.4-5 defines a federally mandated requirement to include "a requirement that the commission determines is imposed on an energy utility by the federal government in connection with any of the following: (2) The federal Water Pollution Control Act (33 U.S.C. 1251 *et seq.*)" and also includes "(7) Any other law, order, or regulation administered or issued by the United States Environmental Protection Agency, the United States

Department of Transportation, the Federal Energy Regulatory Commission, or the United States Department of Energy."

The description of the Culley 3 Compliance Projects was set forth in the direct testimonies of Ms. Fischer and Ms. Retherford. The Culley 3 Compliance Projects consist of (1) conversion of the current wet bottom ash collection system to a dry handling bottom ash system; (2) installation of a spray dryer evaporator system; and (3) the closure of the Culley West ash pond and construction of a new lined process water and storm water retention pond in its place. This new retention pond will be constructed on the location of the existing ash pond due to space limitations. No party disputed that the dry handling bottom ash conversion or spray dryer evaporator system qualify as compliance projects to meet federally mandated requirements. The OUCC challenged whether the closure of the existing pond qualified for relief but did not contend that it was not federally mandated. For the reasons described below, we find that these projects all constitute compliance projects to meet federally mandated requirements as those terms are defined in Ind. Code §§ 8-1-8.4-2 and -5.

Vectren South witness Retherford testified that the dry handling bottom ash system is required to comply with the ELG Rule, which was promulgated under the federal Water Pollution Control Act. Petitioner's Exhibit No. 9, p. 11. The ELG rule prohibits further wet handling of fly and bottom ash. This system will enable ash from Culley Unit 3 to be disposed of in a landfill, hauled back to a surface mine in accordance with applicable surface mining regulation or recycled rather than being washed into the ash pond as part of a water discharge.

Ms. Retherford further explained that the spray dryer evaporator system was necessary to ensure compliance with ELG-imposed limits on FGD wastewater discharge. She noted that this system functions effectively as a ZLD system and enables Vectren South to utilize the alternative ELG-imposed compliance date of December 31, 2023, and to meet future more stringent ELG wastewater discharge limits.

Ms. Retherford testified that construction of a new, lined process and storm water retention pond is required to comply with the ELG Rule. As we have already noted, projects necessary to comply with the ELG Rule, promulgated pursuant to the federal Water Pollution Control Act (33 U.S.C. 1251 *et seq.*), constitute a federally mandated requirement. The only dispute, raised by OUCC witness Aguilar, pertains to Vectren South's plans to close the existing Culley West pond so that the new lined pond can be built at the site. Witness Retherford testified that there are two reasons the Culley West pond is closing: (1) the pond was taken out of service prior to the 2015 deadline and the CCR rule requires that it be closed by 2020; and (2) the current space limitations require that the new stormwater retention and process water pond be constructed on the current location. Thus, there is no dispute that costs associated with the construction of the new lined pond are incurred pursuant to a federally mandated requirement. The dispute is whether the costs to close the Culley West pond so that the new pond can be built on top of that location, also qualify as federally mandated costs.

The OUCC identifies three reasons closure costs for the Culley West pond should not be considered federally mandated costs. First, OUCC witness Aguilar contends that Vectren South has been collecting depreciation and asset retirement costs in base rates, which include the closure of ash ponds. Public's Exhibit No. 1, p. 28. However, Vectren South witness Retherford responded that finalization of the CCR rule on April 17, 2015 imposed more stringent requirements to close the ash pond. The CCR rule imposed an obligation to dewater, cap and/or remove ponded ash. Petitioner's Exhibit No. 9-R, pp. 24-25.

On rebuttal, Mr. Swiz stated Vectren South's existing depreciation rates include an estimated level of cost of removal that was designed well before the implementation of requirements to close the ponds in accordance with the environmental regulations described by Ms. Retherford. The assumed removal costs in the demolition study provided in Cause No. 43839 (Vectren South's most recent general rate case), estimated $1.1 million to close both of the Culley Ash Ponds based on cost of backfill, grading and seeding. By comparison, the estimate for closure of one ash pond in this proceeding is $19.969 million. Petitioner's Exhibit No. 13-R, pp. 6-7; Petitioner's Administrative Notice 1.

Consequently, we find that costs associated with CCR closure have not been included in Vectren South's depreciation rates, which were last updated prior to finalization of the CCR Rule.

Second, the OUCC contends that other utilities are not tracking pond closure costs as Federally-Mandated CCR Projects. Public's Exhibit No. 1, p. 28. Vectren South witness Swiz noted that no utility had proposed such recovery yet but that one utility specifically indicated that it would present closure related activities as recoverable under the Federal Mandate Statute. Petitioner's Exhibit No. 13-R, pp. 6-7. Mr. Swiz explained that Duke, IPL and NIPSCO did not ask for recovery of their pond closure costs in the proceedings Ms. Aguilar cited, and in fact the order in Cause No. 44765 specifically notes that Duke anticipates presenting closure related activities of existing surface impoundments and their associated costs in a future proceeding. Petitioner's Exhibit No. 13-R, p. 6, citing *Duke Energy Indiana*, Cause No. 44765, at *7 (IURC May 24, 2017). Each of the cases Ms. Aguilar cited were settled cases containing non-precedential language. Nevertheless, Mr. Swiz pointed out that the NIPSCO Order in Cause No. 44872, suggests that the OUCC agreed that closure costs can be recovered as federally mandated costs. Petitioner's Exhibit No. 13-R, p. 7.

Third, the OUCC contends that Vectren South should have presented alternative suitable locations to the West Pond for consideration. However, Ms. Retherford testified that the location was chosen because there was limited space at the Culley generating station. In other words, there was not an alternate location to explore. The statutory requirement to consider options does not require a utility to present alternatives that are not practical or feasible. Accordingly, we find the Culley 3 Compliance Projects are all federally mandated requirements and that Vectren South described them in its application.

(2) Energy utilities seeking recovery of Federally Mandated Costs must establish that the costs are incurred in connection with a compliance project, including capital, operating, maintenance, depreciation, tax or financing costs and describe the costs to be recovered. Ind. Code §§ 8-1-8.4-4 and -6(b)(1)(B). We have already found that the Culley 3 Compliance Projects constitute projects required by federally mandated requirements. Consequently, the costs associated with these projects constitute Federally Mandated Costs. These costs will consist of capital, operating, maintenance, depreciation, tax and financing costs. Vectren South identified the estimated costs to be recovered as Federally Mandated Costs. Costs associated with the dry handling bottom ash handling system and spray dryer evaporator system were identified by Vectren South witness Fischer. Petitioner's Exhibit No. 6, pp. 16-18, 26-28. Costs associated with the construction of a new lined process water and storm water retention pond were identified in Ms. Retherford's testimony. Petitioner's Exhibit No. 9, Attachment AMR-1. No party disputed the cost estimates for the Culley 3 Compliance Projects. Based on the evidence presented, we find that Vectren South has identified

federally mandated costs and reasonably described those costs. Those total costs are $95 million, and they are hereby approved. Petitioner's Exhibit No. 4, p. 26.

(3) Compliance with Federally Mandated Requirements (Ind. Code §§ 8-1-8.4-6(b)(1)(C)) and 8-1-8.4-7(b)(3)). No party disputed that the Culley 3 Compliance Projects will allow Vectren South to comply with ELG and CCR or that ELG and CCR are federally mandated. We previously addressed the OUCC's objections related to appropriateness of recovery. We have already found that the ELGs and CCR Rule are federally mandated requirements within the meaning of Ind. Code §§ 8-1-8.4-5 and 8-1-8.4-6(b)(1)(A) and 8-1-8.4-7(b)(3). Based on the evidence presented, we find that Vectren South's Culley 3 Compliance Projects, will allow the utility to comply with the ELGs and the CCR Rule. Therefore, we find that Vectren South has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(C).

(4) Alternative Plans for Compliance (Ind. Code §§ 8-1-8.4-6(b)(1)(D) and 8-1-8.4-7(b)(3)). Ind. Code § 8-1-8.4-6(b)(1)(D) requires the Commission to examine "[a]lternative plan that demonstrate that the proposed compliance project is reasonable and necessary." Vectren South witness Diane Fischer testified about Black & Veatch's evaluation of the ELG Compliance Program for Culley to identify potential FGD discharge water treatment alternatives and ash transport water alternatives that could be implemented to comply with the ELGs. She sponsored two written reports setting forth Black & Veatch's analyses of the alternatives. Ms. Fischer testified that each of the potential discharge treatment technology alternatives assessed by Black & Veatch were screened for design concept feasibility, capital expense and operating expense.

With respect to FGD discharge water treatment, two main treatment alternatives were considered: (1) FGD treatment and discharge; and (2) zero liquid discharge ("ZLD"). Three technology types were evaluated within these two treatment alternatives: (1) for FGD treatment and discharge, physical/chemical pretreatment with biological treatment technology, (2) for ZLD, spray dryer evaporator technology, and (3) also for ZLD, brine concentrator/crystallizer technology. Ms. Fischer testified that multiple vendors providing such technologies were evaluated. A sensitivity analysis was then performed for each technology and vendor. Ms. Fischer's Discharge Treatment Report also included a cost assessment of all alternatives considered. Petitioner's Exhibit No. 10, p. 7. Ms. Fischer testified that Black & Veatch provided Vectren South with a final overall assessment of each technology and vendor offering based on Black & Veatch's analysis and the following attributes: (1) start-up/ramp up reliability; (2) technology readiness risk; (3) adaptability to sensitivity analysis scenarios; (4) operation and control risk; (5) heat rate impact risk; (6) number of operators; (7) capital and annual O&M costs; (8) susceptibility to future environmental regulations; (9) overall financial stability and credit rating. Black & Veatch ultimately recommended that Vectren move forward to a detailed engineering phase with Stochastic Differential Equation ("SDE") type technology if the maximum FGD wastewater flow rate of between 50 and 80 gpm is achieved through future testing and operations. Ms. Fischer explained the SDE solution ranks the highest among all technologies based on the attributes discussed above and the solution is economically viable and provides a zero discharge solution if the minimum FGD wastewater flow rate of between 50 and 80 gpm is achieved. The conceptual design evaluation indicated the SDE can be feasibly located and tied into the existing equipment at Culley. In addition, Ms. Fischer stated the ZLD solution provides certainty that any future change in EPA regulations would not apply at Culley since there would be no discharge of FGD wastewater.

With respect to ash transport, Ms. Fischer described Black & Veatch's analysis to identify alternative ash transport solutions that could be implemented at Culley to comply with ELG requirements, focused specifically on identifying options for removal and dewatering of bottom ash from the Culley Unit 3 boiler with truck transport and disposal of the dry material at an off-site location. Black & Veatch evaluated two categories of technologies: (1) dry conversion of the bottom ash system and (2) closed loop wet sluicing system. For dry conversion system, Black & Veatch evaluated a submerged chain conveyor under the existing bottom ash hopper. For the closed loop wet sluicing system, Black & Veatch evaluated both a dewatering bunker and a remote submerged chain conveyor. In comparing all technologies, Black & Veatch used the following quality attributes to select the preferred treatment: technical feasibility; total installed cost, O&M cost, estimated additional manpower ("FTE"), estimated footprint, major equipment, advantage, disadvantages and reliability. Ms. Fischer's testimony discussed in detail the advantages and disadvantage of each alternative. Black & Veatch prepared cost estimates for all technologies considered for addressing ash transport water. Black & Veatch ultimately recommended the submerged chain conveyor for Culley 3 compliance with ELG requirements, due to the complexity of design and comparatively higher installed cost of the other alternatives.

The only evidence offered in opposition as being an alternative plan was the OUCC's conclusory statement about possible alternative locations for the new lined pond. As we have previously found, the chosen site was selected because there are no alternative locations.

While the Commission gives significant weight to cost-effective planning and decision making when considering alternatives, the Federal Mandate Statute does not require that a utility demonstrate that the chosen compliance plan is the least cost option. Consistent with the Commission's finding in Indianapolis Power and Light's recent proceeding, Cause No. 44794 (IURC 4/26/2017), p. 30, 2017 Ind. PUC LEXIS 114, *92, (finding "it is important that the Petersburg Station is able to continue to operate on coal and protect customers from potential price volatility in the gas markets"), a reasonable alternative can be, and often is, a solution that includes risk balancing through a diversified portfolio.

Based on the evidence presented, we find that Vectren South considered alternative plans for compliance with the ELGs and the CCR Rule. The evidence shows that the Culley 3 Compliance Projects are reasonable and necessary.

(5) Useful Life of the Facility (Ind. Code §§ 8-1-8.4-6(b)(1)(E) and 8-1-8.4-7(b)(3)). Mr. Games testified that the investments in the Culley 3 Compliance Projects will allow for the continued operation of Vectren South's most efficient coal fired unit. Ms. Retherford described the environmental regulations requiring the Culley 3 Compliance Projects in order for Culley Unit 3 to continue operating. Ms. Retherford explained how closure of the Culley West pond will extend the useful life of Culley 3, because closure of the Culley West pond is necessary to provide a suitable location to construct a new pond that can continue to take non-CCR process water discharged from Culley Unit 3 and plant stormwater (i.e. surface water) which flows into the West Pond. Without this new lined process and stormwater pond, continued operation consistent with applicable regulations would be impossible after the Culley East pond commences closure.

No party disputes that issuance of a CPCN for the Culley 3 Compliance Projects will extend the useful life of Vectren South's Culley 3 unit or that Culley 3 would be required to retire in the near future if the Culley 3 Compliance Projects are not completed.

Based on the evidence presented, we find that Vectren South has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(E).

(6) Conclusion. We find that the Culley 3 Compliance Projects will allow Vectren South to comply directly or indirectly with one or more federally mandated requirements and that public convenience and necessity will be served by the Culley 3 Compliance Projects.

ii. Accounting and Ratemaking Issues Associated with Culley Compliance Projects. Ind. Code § 8-1-8.4-7(c) states:

> If the commission approves under subsection (b) a proposed compliance project and the projected federally mandated costs associated with the proposed compliance project, the following apply:
> (1) Eighty percent (80%) of the approved federally mandated costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism that allows the timely recovery of the approved federally mandated costs. The Commission shall adjust the energy utility's authorized net operating income to reflect any approved earnings for purposes of IC 8-1-2-42(d)(3)and IC 8-1-2-42(g)(3).
> (2) Twenty percent (20%) of the approved federally mandated costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, based on the overall cost of capital most recently approved by the commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the commission.
> (3) Actual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent (25%) shall require specific justification by the energy utility and specific approval by the commission before being authorized in the next general rate case filed by the energy utility with the commission.

(1) Accounting and Ratemaking Treatment for ECA. Vectren South requests authority to implement a new annual rate adjustment mechanism ("ECA") pursuant to Ind. Code § 8-1-8.4-7 for the timely and periodic recovery of 80% of the federally mandated costs. Vectren South also requests approval of proposed changes to its electric service tariff relating to the proposed ECA mechanism, including the proposed Appendix E. Ind. Code §8-1-8.4-8 provides that an energy utility may, in a timely manner, recover 80% of all federally mandated costs through a periodic rate adjustment mechanism. Ind. Code §§ 8-1-8.4-4 and 8-1-8.4-7 provide that such costs include capital, AFUDC, O&M, depreciation, tax, and financing costs.

Vectren South witness Swiz described how the eligible costs associated with the Culley 3 Compliance Projects will be incorporated into the proposed ECA mechanism. He testified Vectren South will prepare in each annual filing a revenue requirement calculation accumulating all eligible costs incurred through December 31 of the previous calendar year. To provide for timely recovery, Mr. Swiz testified the proposed ECA will project an annualized level of expense related to the approved projects for the 12-month effective period. Mr. Swiz stated the annual revenue requirements

will capture eligible new capital investments (both in service and Construction Work in Progress) related to the Culley 3 Compliance Projects, multiplied by the applicable rate of return, with depreciation, O&M and property tax expenses associated with the projects, and recovery of the regulatory assets recorded through interim deferral of depreciation expense, plan development expense, and PISCC, added to the resulting total. The revenue requirement for those projects will be the basis for the recovery of 80% of the eligible revenue requirement amounts in each annual ECA filing.

Mr. Swiz also described Vectren South's proposal to defer and subsequently recover depreciation expense as well as costs associated with development of the Culley 3 Compliance Projects through the ECA. The cumulative deferred balances of the regulatory assets recorded through interim deferral of such depreciation expenses would be amortized over the remaining life of the assets (20 years) and the amortization amount would be included in the ECA revenue requirements. Mr. Swiz stated the costs of development of the projects would be included for recovery within the ECA, with the balance amortized over a period of three years.

Vectren South proposes the pre-tax return on the new capital investment will be calculated by multiplying the pre-tax rate of return, based on the weighted average cost of capital ("WACC"), by total new capital investment related to the approved projects. Mr. Swiz testified Vectren South proposes to use a WACC in the ECA based upon the most recent approved WACC within Vectren South's TDSIC mechanism under Cause No. 44910, which is based on a return on equity ("ROE") of 10.4% as approved in Cause Nos. 43111 and 43839, Vectren South's two most recent base rate cases. Mr. Swiz stated the equity component of the rate used in the ECA revenue requirement calculation will be grossed up for recovery of income taxes, both state and federal, at then current rates.

Mr. Swiz testified that approved recoveries within each ECA filing will be calculated by taking the billing determinants by month multiplied by the applicable rates and charges for the ECA period. Any under recoveries resulting from instances in which ECA rates and charges are not in place for a full month will be recovered as an under-recovery variance in a subsequent ECA proceeding. Vectren South proposes to allocate ECA costs pursuant to the four-coincident peak allocation percentages for Vectren South utilized in its Cause No. 43406 RCRA15 and 43405 DSMA15 rate mechanisms.

With respect to the treatment of operating income, Mr. Swiz testified Vectren South will adjust its statutory earnings test under Ind. Code § 8-1-2-42(d)(3) to include the incremental earnings from approved ECA filings.

Mr. Swiz testified Vectren South proposes to file its ECA petitions and cases in chief annually, on May 1 of each year, with new ECA rates and charges becoming effective August 1 of each year. Each filing will be based on capital investments and expenses through the twelve months ended December of the prior calendar year. Variances will be reconciled in each ECA filing and recovered over the subsequent 12 month rate effective period. Vectren South seeks approval of its proposed Sheet No. 69, Appendix E, Environmental Cost Adjustment. Additional changes to Vectren South's rate schedules in its tariff are needed to reflect that the ECA will be applied monthly.

Industrial Group witness Gorman recommended that the ELG costs associated with the Culley 3 Compliance Projects be recovered within a base rate proceeding and not through the proposed ECA. He cited Vectren South's overall rate of return and stated Vectren South's costs have declined since

the last base rate case. He also suggested that Vectren South should be permitted to recover a return on investment of no more than 9.8%.

Mr. Swiz explained on rebuttal that under the statutory test under Ind. Code § 8-1-2-42(d) and -42.3, performed in Vectren South's most recent FAC proceedings as of the time his rebuttal testimony was filed (Cause No. 38708 FAC 120), Vectren South's comprehensive earnings compared to authorized levels, including both changes in expenses and revenues, show that Vectren South is currently under-earning by approximately $6.5 million of net operating income and has been under-earning since February 2017. Mr. Swiz explained that depreciation and operating expense are driving much of these results, and Mr. Gorman does not capture those expenses in his calculation.

Eligibility for recovery through Ind. Code ch. 8-1-8.4 is not contingent on whether other costs have declined to offset the new federally mandated costs. Once we have made the required findings, 80% of the federally mandated costs "shall be recovered by the energy utility through a periodic retail rate adjustment mechanism." Ind. Code § 8-1-8.4-7(c)(1). In any event, we find that Mr. Swiz has adequately explained why Mr. Gorman's position is incorrect.

Mr. Swiz testified that pursuant to Ind. Code § 8-1-8.4-7, Vectren South seeks ratemaking treatment for 80% of the costs associated with the Culley 3 Compliance Projects through its proposed ECA mechanism. Specifically, Vectren South seeks timely recovery of all federally mandated costs associated with the Culley 3 Compliance Projects, including capital costs, AFUDC, post-in-service carrying cost charges ("PISCC"), O&M, depreciation expense, property tax expense, and other taxes, with 80% recovered through the ECA and the balance deferred for recovery in Vectren South's next rate case.

Vectren South proposes to implement construction work in progress ("CWIP") ratemaking treatment related to the recovery of financing costs incurred during construction of the Culley 3 Compliance Projects. In connection with CWIP ratemaking treatment, Vectren South will remove from the AFUDC-eligible balance the amount of investment included for recovery in the ECA, so that only the amount of the Culley 3 Compliance Projects investment not currently being recovered in the ECA would be eligible for AFUDC.

Mr. Swiz testified that Vectren South proposes to accrue post-in-service carrying charges on all eligible new capital investment from the date it is placed in service until the date it is included in rates. He explained the PISCC balances will be multiplied by the pre-tax rate of return within the ECA revenue requirement, at the WACC rate described herein. Unlike other utilities who have been granted such authority, Vectren South is not seeking to accrue and subsequently recover in the next base rate case PISCC on the 20% deferred balance discussed below.

OUCC witness Aguilar opposed Vectren South's request to recover pond closure costs for the Culley 3 Compliance Projects as part of the ECA because the OUCC's position is that Vectren South is already collecting pond closure costs within its depreciation rates. Ms. Aguilar also testified that neither Duke, IPL, nor NIPSCO are tracking pond closure costs. We have already addressed these positions and rejected them.

Based on the evidence presented, we find that the proposed ECA mechanism should allow for the timely and periodic recovery of 80% of Vectren South's approved federally mandated costs. We further find that Vectren South's request for approval to adjust its authorized net operating income to

reflect an approved earnings associated with the Culley 3 Compliance Project for purposes of Ind. Code §§ 8-1-2-42(d)(3) and 8-1-2-42(g)(3) is consistent with Ind. Code § 8-1-8.4-7(c)(1).

Vectren South is authorized to defer (until captured within the ECA mechanism) and recover 80% of the approved federally mandated costs incurred in connection with the Culley 3 Compliance Projects through the approved ECA Mechanism pursuant to Ind. Code § 8-1-8.4-7, including capital, O&M, depreciation, taxes, financing, and carrying costs based on the current overall WACC and AFUDC. Vectren South is authorized to utilize CWIP ratemaking treatment for the Culley 3 Compliance Projects through the proposed ECA mechanism. Vectren South is authorized to defer post-in service costs of the Culley 3 Compliance Projects, including carrying costs based on the current overall WACC, depreciation, taxes and operating and maintenance expenses on an interim basis until such costs are recognized for ratemaking purposes through Vectren South's ECA mechanism or otherwise included for recovery in Vectren South's base rates in its next general rate case. Vectren South is authorized to defer and recover through the ECA mechanism 80% of its federally mandated costs, including but not limited to federally mandated costs incurred prior to and after approval of a final order in this proceeding to the extent that such costs are reasonable and consistent with the scope of the Culley 3 Compliance Projects described in Vectren South's evidence. Vectren South's proposed cost allocation factors are also approved.

(2) Accounting and Ratemaking Treatment for Deferred Costs. Indiana Code § 8-1-8.4-8 provides that 20% of the approved federally mandated costs, including depreciation, AFUDC, and PISCC, based on the overall cost of capital most recently approved by the Commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the Commission. Vectren South proposes to defer as a regulatory asset 20% of all federally mandated costs incurred in connection with these projects.

Based on the evidence presented, the Commission finds Vectren South is authorized to defer 20% of the federally mandated costs incurred in connection with the Culley 3 Compliance Projects, and Vectren South may recover the deferred costs in its next general rate case as allowed by Ind. Code § 8-1-8.4-7(c)(2).

(3) Depreciation Treatment. Vectren South proposes to utilize a depreciation rate of 5%, representing a 20-year life on these investments. Mr. Swiz testified the proposed depreciation rate for the investments aligns with the estimated remaining life of Culley Unit 3.

No party opposed Vectren South's proposed depreciation rate for the investments required for the Culley 3 Compliance Projects.

Based on the evidence presented, we find that Vectren South's proposal to depreciate the individual projects included in the Culley 3 Compliance Projects based on a 5% depreciation rate is reasonable and is approved.

C. Recovery of Prior Pollution Control Investments. Our January 28, 2015 and June 22, 2016 Orders in Cause No. 44446 (the "44446 Orders") (1) granted Vectren South a CPCN for A.B. Brown Unit 1 and 2, Culley Unit 3 and Warrick Unit 3 clean coal technology projects and (2) authorized Vectren South to recover federally mandated costs associated with federally mandated requirements at A.B. Brown Units 1 and 2 (collectively the "MATS Projects"). Rather than recovering

the costs of the MATS Projects through a tracking mechanism as authorized by Ind. Code § 8-1-8.4-7, Vectren South sought, and we granted, authority to defer these costs for recovery in a future proceeding. Vectren South now seeks to commence recovery of the MATS Projects' costs through the ECA pursuant to Ind. Code § 8-1-8.4-7.

Vectren South witness Swiz described the proposed recovery through the ECA in more detail. He indicated that Vectren South proposes recovery of the MATS Projects to begin on January 1, 2019 with the approval of ECA rates and charges recovering the specified revenue requirement. In accordance with applicable statutory requirements, Vectren South proposes to recover the 80% of eligible revenue requirements amounts for post-in-service carrying costs, incremental depreciation and property taxes and financing costs that Vectren South incurred to construct the MATS Projects and deferral of the remaining 20% of these costs for subsequent recovery in a base rate case. Vectren South will prepare an annual revenue requirement as part of the ECA to capture eligible capital investments in plant related to the MATS Projects, multiplied by the applicable rate of return, with depreciation, O&M, and property tax expenses associated with the MATS Projects added to the resulting total. To provide for timely recovery, Vectren South's proposed ECA will project an annualized level of expense related to these approved projects for the 12-month effective period.

Depreciation associated with the MATS Projects will be based on the currently approved depreciation rates applicable to the assets, as approved in Vectren South's last electric base rate case (Cause No. 43839). The pre-tax return on the new capital investment will be calculated by multiplying the pre-tax rate of return, based on the WACC, by total new capital investment related to the approved projects. Vectren South proposes to use a WACC in the ECA based upon the most recent approved WACC within Vectren South's TDSIC mechanism, Cause No. 44910. This WACC, approved by the Commission, represents an updated actual capital structure as of the cut-off date of each TDSIC filing, and includes the typical items captured in Vectren South's base rate case capital structure. This rate will be used in the ECA revenue requirement calculation, and the equity component will be grossed up for recovery of income taxes, both state and federal, at then current rates. O&M expense included for recovery in the ECA will reflect an annualized level of expense related to the MATS Projects. This O&M expense represents incremental chemical costs and other expenses associated only with the MATS Projects.

No party objected to Vectren South's proposal to commence recovery of the MATS Projects' costs, currently being deferred, through the ECA. We previously found the MATS Projects costs qualify as federally mandated costs in the 44446 Orders. While Vectren South proposed, and we approved of, deferral of these costs in lieu of the recovery through a periodic retail rate adjustment mechanism, Vectren South now seeks to recover the costs in accordance with Ind. Code § 8-1-8.4-7(c). We find that Vectren South shall be authorized to commence recovery of these MATS Projects' costs pursuant to Ind. Code § 8-1-8.4-7 through the ECA in accordance with the procedures outlined in Mr. Swiz's testimony.

6. Confidentiality. Vectren South filed motions for protection and nondisclosure of confidential and proprietary information on March 20, 2018, August 21, 2018, and September 10, 2018, respectively. In its motions, Vectren South states certain information redacted in the evidence is confidential, proprietary, competitively sensitive, and/or trade secrets. Docket entries were issued on March 29, August 27, and October 4, 2018 finding such information to be preliminarily confidential and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. The confidential information was subsequently submitted under seal. The Commission finds the

information for which Vectren South seeks confidential treatment is confidential trade secret information pursuant to Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3, is exempt from public access and disclosure by Indiana law, and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Vectren South's request for a certificate of public convenience and necessity under Ind. Code ch. 8-1- 8.5 to construct an 850 MW CCGT and all associated relief requested is denied.

2. Vectren South's request for a certificate of public convenience and necessity for the Culley 3 Compliance Projects pursuant to Ind. Code ch. 8-1-8.4 and all associated relief requested is approved.

3. Vectren South's proposed recovery of federally mandated costs approved in connection with Cause No. 44446 through the ECA is approved as described in this Order.

4. Vectren South's proposed ECA, and Vectren South's proposed Sheet No. 69, Appendix E of its tariff to implement such ECA is approved.

5. The Confidential Information submitted under seal in this Cause pursuant to Vectren South's requests for confidential treatment is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall continue to be held as confidential and exempt from public access and disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4.

6. This Order shall be effective on and after the date of its approval.

HUSTON, KREVDA, OBER, AND ZIEGNER CONCUR; FREEMAN ABSENT:

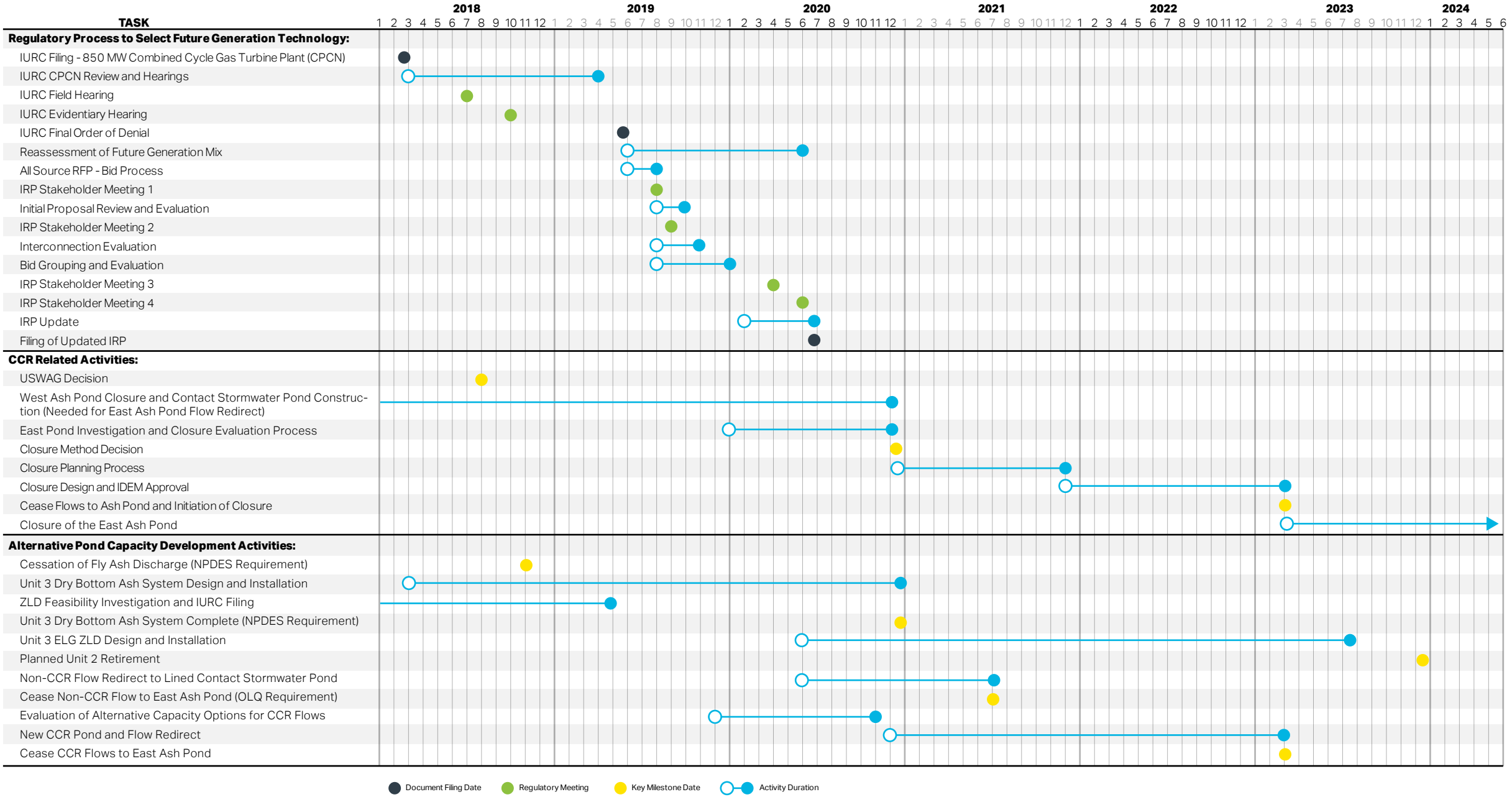
APPROVED: APR 24 2019

I hereby certify that the above is a true and correct copy of the Order as approved.

Mary M Becerra

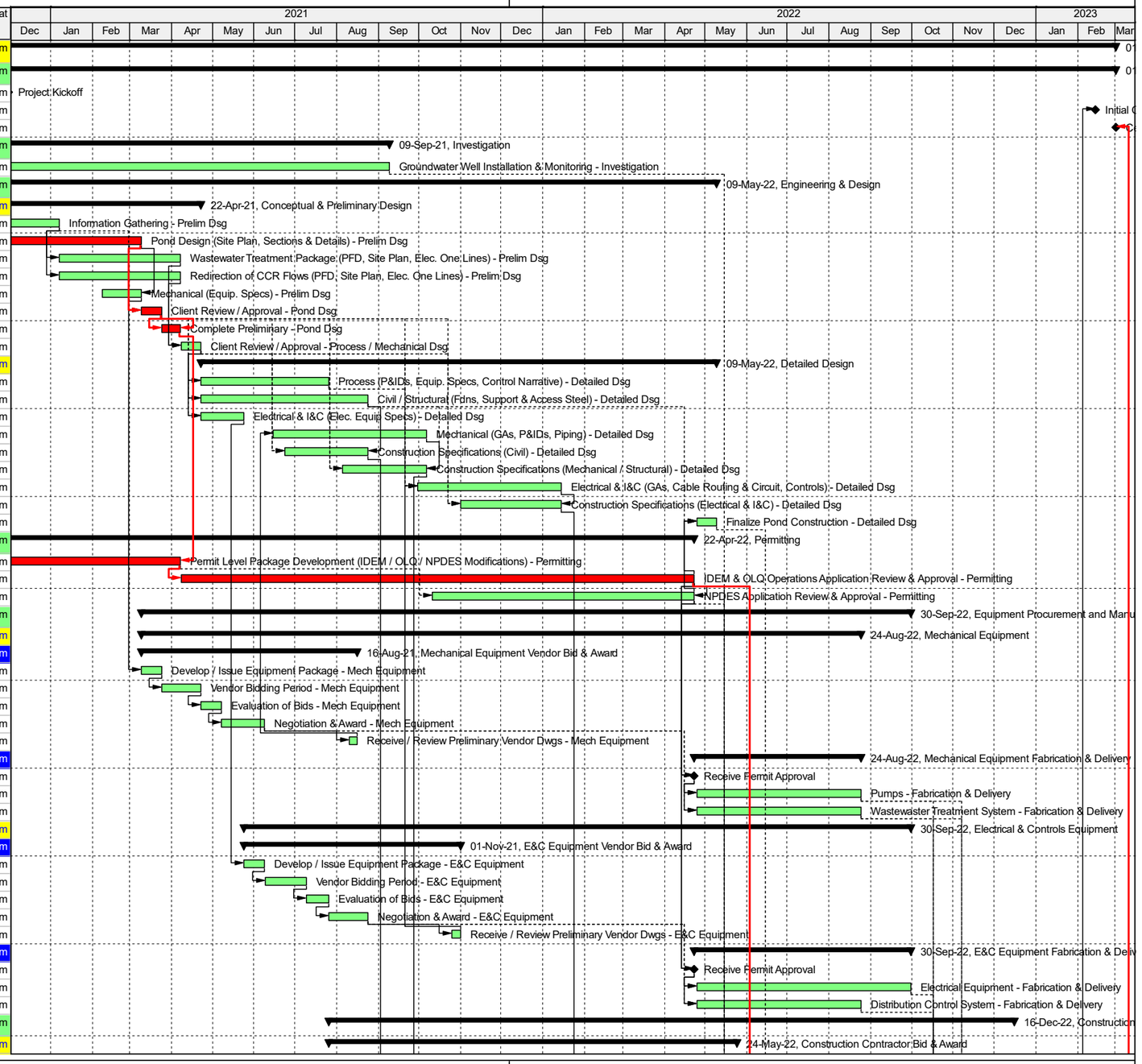
Mary M. Becerra
Secretary of the Commission

Appendix B
Schedule Activities and Milestone


TASK
2018
2019
2020
2021
2022
2023
2024
1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4 5 6
Regulatory Process to Select Future Generation Technology:
IURC Filing - 850 MW Combined Cycle Gas Turbine Plant (CPCN)
IURC CPCN Review and Hearings
IURC Field Hearing
IURC Evidentiary Hearing
IURC Final Order of Denial
Reassessment of Future Generation Mix
All Source RFP - Bid Process
IRP Stakeholder Meeting 1
Initial Proposal Review and Evaluation
IRP Stakeholder Meeting 2
Interconnection Evaluation
Bid Grouping and Evaluation
IRP Stakeholder Meeting 3
IRP Stakeholder Meeting 4
IRP Update
Filing of Updated IRP
CCR Related Activities:
USWAG Decision
West Ash Pond Closure and Contact Stormwater Pond Construc-tion (Needed for East Ash Pond Flow Redirect)
East Pond Investigation and Closure Evaluation Process
Closure Method Decision
Closure Planning Process
Closure Design and IDEM Approval
Cease Flows to Ash Pond and Initiation of Closure
Closure of the East Ash Pond
Alternative Pond Capacity Development Activities:
Cessation of Fly Ash Discharge (NPDES Requirement)
Unit 3 Dry Bottom Ash System Design and Installation
ZLD Feasibility Investigation and IURC Filing
Unit 3 Dry Bottom Ash System Complete (NPDES Requirement)
Unit 3 ELG ZLD Design and Installation
Planned Unit 2 Retirement
Non-CCR Flow Redirect to Lined Contact Stormwater Pond
Cease Non-CCR Flow to East Ash Pond (OLQ Requirement)
Evaluation of Alternative Capacity Options for CCR Flows
New CCR Pond and Flow Redirect
Cease CCR Flows to East Ash Pond
Document Filing Date
Regulatory Meeting
Key Milestone Date
Activity Duration

Appendix C
Detailed Schedule for Development of Alternative Capacity

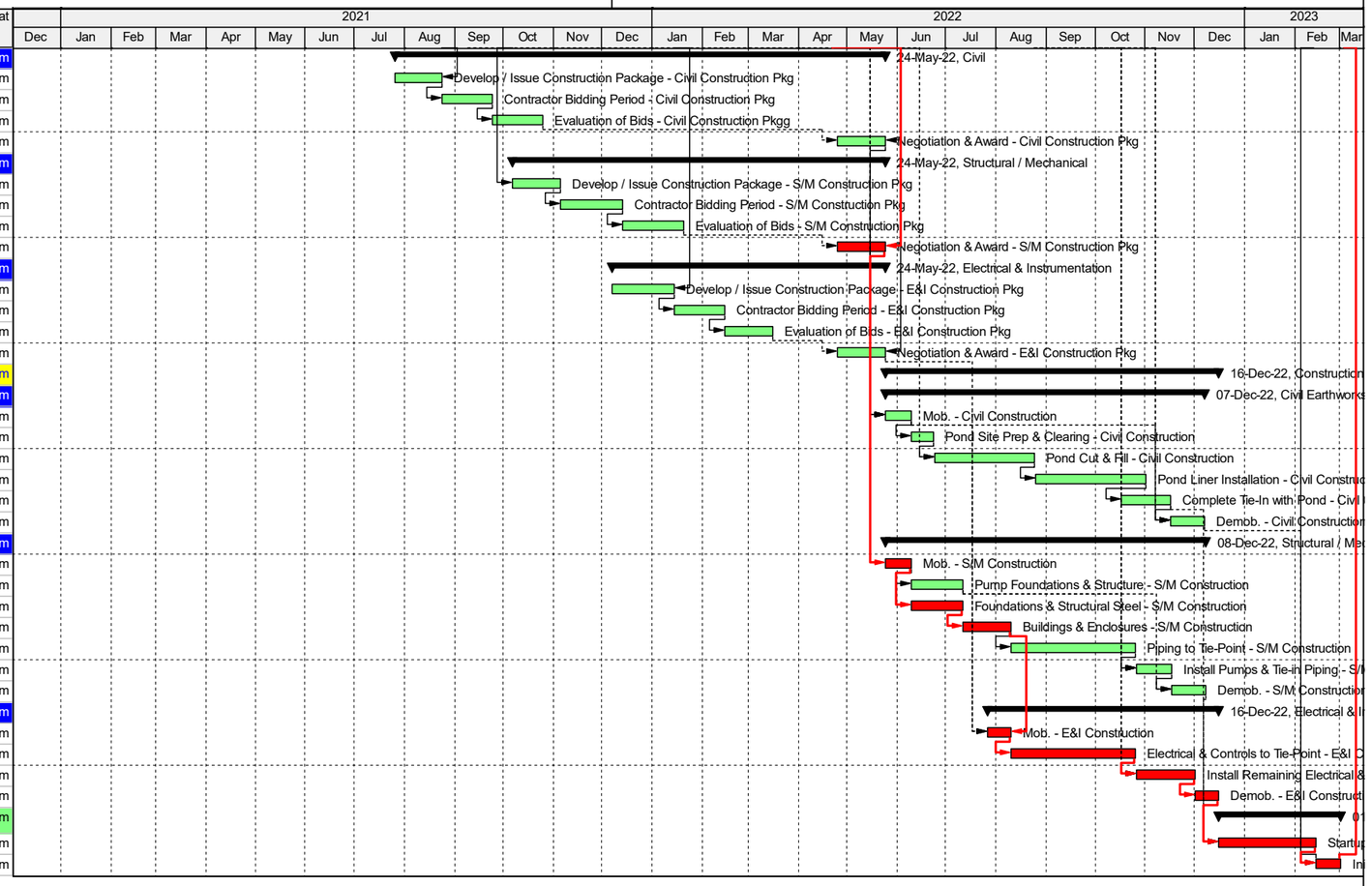
Activity ID	Activity Name	Duration	Start	Finish	Total Float
FBC New Lined CCR Pond_RevH		25.7m	01-Dec-20	01-Mar-23	0.0m
Milestones		25.7m	01-Dec-20	01-Mar-23	0.0m
A1350	Project Kickoff	0.0m	01-Dec-20*		0.0m
A1360	Initial Operation	0.0m	14-Feb-23		0.5m
A1750	Cease Flows to East Ash Pond	0.0m		01-Mar-23*	0.0m
Investigation		9.0m	01-Dec-20	09-Sep-21	8.8m
A1010	Groundwater Well Installation & Monitoring - Investigation	9.0m	01-Dec-20	09-Sep-21	8.8m
Engineering & Design		16.5m	01-Dec-20	09-May-22	2.3m
Conceptual & Preliminary Design		4.5m	01-Dec-20	22-Apr-21	3.3m
A1000	Information Gathering - Prelim Dsg	1.0m	01-Dec-20	07-Jan-21	2.0m
A1020	Pond Design (Site Plan, Sections & Details) - Prelim Dsg	3.0m	01-Dec-20	09-Mar-21	0.0m
A1040	Wastewater Treatment Package (PFD, Site Plan, Elec. One Lines) - Prelim	3.0m	07-Jan-21	07-Apr-21	3.3m
A1430	Redirection of CCR Flows (PFD, Site Plan, Elec. One Lines) - Prelim Dsg	3.0m	07-Jan-21	07-Apr-21	3.3m
A1540	Mechanical (Equip. Specs) - Prelim Dsg	1.0m	08-Feb-21	09-Mar-21	3.1m
A1450	Client Review / Approval - Pond Dsg	0.5m	09-Mar-21	24-Mar-21	0.0m
A1640	Complete Preliminary - Pond Dsg	0.5m	24-Mar-21	07-Apr-21	0.0m
A1740	Client Review / Approval - Process / Mechanical Dsg	0.5m	08-Apr-21	22-Apr-21	3.3m
Detailed Design		12.0m	22-Apr-21	09-May-22	2.3m
A1050	Process (P&IDs, Equip. Specs, Control Narrative) - Detailed Dsg	3.0m	22-Apr-21	26-Jul-21	6.5m
A1070	Civil / Structural (Fdns, Support & Access Steel) - Detailed Dsg	4.0m	22-Apr-21	24-Aug-21	4.5m
A1560	Electrical & I&C (Elec. Equip Specs) - Detailed Dsg	1.0m	22-Apr-21	24-May-21	3.3m
A1060	Mechanical (GAs, P&IDs, Piping) - Detailed Dsg	3.7m	15-Jun-21	06-Oct-21	3.1m
A1090	Construction Specifications (Civil) - Detailed Dsg	2.0m	23-Jun-21	24-Aug-21	6.3m
A1610	Construction Specifications (Mechanical / Structural) - Detailed Dsg	2.0m	05-Aug-21	06-Oct-21	3.1m
A1080	Electrical & I&C (GAs, Cable Routing & Circuit, Controls) - Detailed Dsg	3.0m	30-Sep-21	14-Jan-22	3.3m
A1440	Construction Specifications (Electrical & I&C) - Detailed Dsg	2.0m	01-Nov-21	14-Jan-22	3.3m
A1270	Finalize Pond Construction - Detailed Dsg	0.5m	25-Apr-22	09-May-22	2.3m
Permitting		16.0m	01-Dec-20	22-Apr-22	0.8m
A1030	Permit Level Package Development (IDEM / OLQ / NPDES Modifications)	4.0m	01-Dec-20	07-Apr-21	0.0m
A1100	IDEM & OLQ Operations Application Review & Approval - Permitting	12.0m	08-Apr-21	22-Apr-22	0.0m
A1110	NPDES Application Review & Approval - Permitting	6.0m	11-Oct-21	22-Apr-22	0.8m
Equipment Procurement and Manufacture		18.2m	09-Mar-21	30-Sep-22	1.1m
Mechanical Equipment		17.0m	09-Mar-21	24-Aug-22	2.3m
Mechanical Equipment Vendor Bid & Award		5.2m	09-Mar-21	16-Aug-21	3.1m
A1120	Develop / Issue Equipment Package - Mech Equipment	0.5m	09-Mar-21	24-Mar-21	3.1m
A1130	Vendor Bidding Period - Mech Equipment	1.0m	24-Mar-21	22-Apr-21	3.1m
A1140	Evaluation of Bids - Mech Equipment	0.5m	22-Apr-21	07-May-21	3.1m
A1150	Negotiation & Award - Mech Equipment	1.0m	07-May-21	08-Jun-21	3.1m
A1550	Receive / Review Preliminary Vendor Dwgs - Mech Equipment	0.2m	10-Aug-21	16-Aug-21	3.1m
Mechanical Equipment Fabrication & Delivery		4.0m	22-Apr-22	24-Aug-22	2.3m
A1290	Receive Permit Approval	0.0m		22-Apr-22	2.3m
A1160	Pumps - Fabrication & Delivery	4.0m	25-Apr-22	24-Aug-22	2.3m
A1170	Wastewater Treatment System - Fabrication & Delivery	4.0m	25-Apr-22	24-Aug-22	2.3m
Electrical & Controls Equipment		15.7m	24-May-21	30-Sep-22	0.8m
E&C Equipment Vendor Bid & Award		5.2m	24-May-21	01-Nov-21	3.3m
A1490	Develop / Issue Equipment Package - E&C Equipment	0.5m	24-May-21	08-Jun-21	3.3m
A1500	Vendor Bidding Period - E&C Equipment	1.0m	09-Jun-21	09-Jul-21	3.3m
A1510	Evaluation of Bids - E&C Equipment	0.5m	09-Jul-21	26-Jul-21	3.3m
A1520	Negotiation & Award - E&C Equipment	1.0m	26-Jul-21	24-Aug-21	3.3m
A1530	Receive / Review Preliminary Vendor Dwgs - E&C Equipment	0.2m	25-Oct-21	01-Nov-21	3.3m
E&C Equipment Fabrication & Delivery		5.2m	22-Apr-22	30-Sep-22	0.8m
A1730	Receive Permit Approval	0.0m		22-Apr-22	0.8m
A1180	Electrical Equipment - Fabrication & Delivery	5.2m	25-Apr-22	30-Sep-22	0.8m
A1190	Distribution Control System - Fabrication & Delivery	4.0m	25-Apr-22	24-Aug-22	2.0m
Construction		16.0m	26-Jul-21	16-Dec-22	1.7m
Construction Contractor Bid & Award		9.5m	26-Jul-21	24-May-22	2.0m



Actual Work | Critical Remaining Work | Summary
Remaining Work | Milestone

AECOM

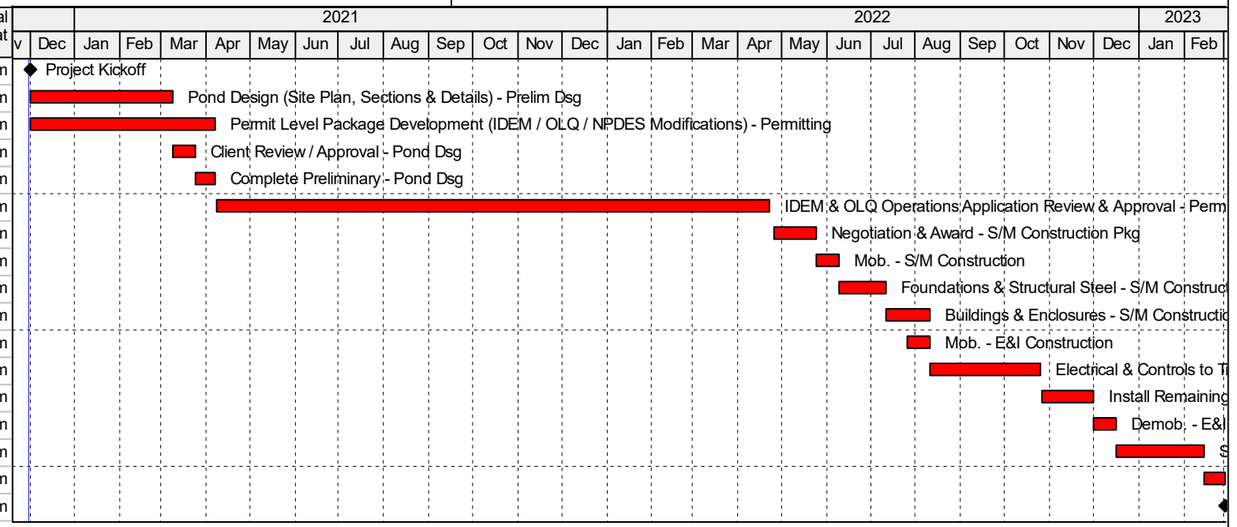
Activity ID	Activity Name	Duration	Start	Finish	Total Float
Civil		9.5m	26-Jul-21	24-May-22	0.8m
A1200	Develop / Issue Construction Package - Civil Construction Pkg	1.0m	26-Jul-21	24-Aug-21	6.3m
A1210	Contractor Bidding Period - Civil Construction Pkg	1.0m	24-Aug-21	24-Sep-21	6.3m
A1220	Evaluation of Bids - Civil Construction Pkgg	1.0m	24-Sep-21	25-Oct-21	6.3m
A1230	Negotiation & Award - Civil Construction Pkg	1.0m	25-Apr-22	24-May-22	0.8m
Structural / Mechanical		7.1m	06-Oct-21	24-May-22	0.0m
A1570	Develop / Issue Construction Package - S/M Construction Pkg	1.0m	06-Oct-21	05-Nov-21	3.1m
A1580	Contractor Bidding Period - S/M Construction Pkg	1.0m	05-Nov-21	13-Dec-21	3.1m
A1590	Evaluation of Bids - S/M Construction Pkg	1.0m	13-Dec-21	20-Jan-22	3.1m
A1600	Negotiation & Award - S/M Construction Pkg	1.0m	25-Apr-22	24-May-22	0.0m
Electrical & Instrumentation		5.3m	07-Dec-21	24-May-22	2.0m
A1390	Develop / Issue Construction Package - E&I Construction Pkg	1.0m	07-Dec-21	14-Jan-22	3.3m
A1400	Contractor Bidding Period - E&I Construction Pkg	1.0m	14-Jan-22	14-Feb-22	3.3m
A1410	Evaluation of Bids - E&I Construction Pkg	1.0m	14-Feb-22	16-Mar-22	3.3m
A1420	Negotiation & Award - E&I Construction Pkg	1.0m	25-Apr-22	24-May-22	2.0m
Construction		6.5m	24-May-22	16-Dec-22	1.7m
Civil Earthworks		6.2m	24-May-22	07-Dec-22	2.0m
A1240	Mob. - Civil Construction	0.5m	24-May-22	09-Jun-22	0.8m
A1250	Pond Site Prep & Clearing - Civil Construction	0.5m	09-Jun-22	23-Jun-22	0.8m
A1260	Pond Cut & Fill - Civil Construction	2.0m	24-Jun-22	24-Aug-22	0.8m
A1280	Pond Liner Installation - Civil Construction	2.2m	25-Aug-22	01-Nov-22	0.8m
A1630	Complete Tie-In with Pond - Civil Construction	1.0m	17-Oct-22	16-Nov-22	0.8m
A1470	Demob. - Civil Construction	0.5m	16-Nov-22	07-Dec-22	2.0m
Structural / Mechanical		6.3m	24-May-22	08-Dec-22	0.3m
A1620	Mob. - S/M Construction	0.5m	24-May-22	09-Jun-22	0.0m
A1650	Pump Foundations & Structure - S/M Construction	1.0m	09-Jun-22	11-Jul-22	3.8m
A1670	Foundations & Structural Steel - S/M Construction	1.0m	09-Jun-22	11-Jul-22	0.0m
A1680	Buildings & Enclosures - S/M Construction	1.0m	11-Jul-22	10-Aug-22	0.0m
A1690	Piping to Tie-Point - S/M Construction	2.5m	10-Aug-22	25-Oct-22	0.3m
A1700	Install Pumps & Tie-in Piping - S/M Construction	0.8m	26-Oct-22	17-Nov-22	0.3m
A1710	Demob. - S/M Construction	0.5m	17-Nov-22	08-Dec-22	0.3m
Electrical & Instrumentation		4.5m	26-Jul-22	16-Dec-22	0.0m
A1340	Mob. - E&I Construction	0.5m	26-Jul-22	10-Aug-22	0.0m
A1320	Electrical & Controls to Tie-Point - E&I Construction	2.5m	10-Aug-22	25-Oct-22	0.0m
A1480	Install Remaining Electrical & Controls - E&I Construction	1.0m	26-Oct-22	01-Dec-22	0.0m
A1460	Demob. - E&I Construction	0.5m	01-Dec-22	16-Dec-22	0.0m
Start-Up & Commissioning		2.2m	16-Dec-22	01-Mar-23	0.0m
A1370	Startup & Commissioning	1.7m	16-Dec-22	14-Feb-23	0.0m
A1380	Initial Operation	0.5m	14-Feb-23	01-Mar-23	0.0m



Actual Work | Critical Remaining Work | Summary
Remaining Work | Milestone

AECOM

Activity ID	Activity Name	Orig. Dur.	Start	Finish	Total Float
A1350	Project Kickoff	0.0m	01-Dec-20*		0.0m
A1020	Pond Design (Site Plan, Sections & Details) - Prelim Dsg	3.0m	01-Dec-20	09-Mar-21	0.0m
A1030	Permit Level Package Development (IDEM / OLQ / NPDES Modifications) - Permitting	4.0m	01-Dec-20	07-Apr-21	0.0m
A1450	Client Review / Approval - Pond Dsg	0.5m	09-Mar-21	24-Mar-21	0.0m
A1640	Complete Preliminary - Pond Dsg	0.5m	24-Mar-21	07-Apr-21	0.0m
A1100	IDEM & OLQ Operations Application Review & Approval - Permitting	12.0m	08-Apr-21	22-Apr-22	0.0m
A1600	Negotiation & Award - S/M Construction Pkg	1.0m	25-Apr-22	24-May-22	0.0m
A1620	Mob. - S/M Construction	0.5m	24-May-22	09-Jun-22	0.0m
A1670	Foundations & Structural Steel - S/M Construction	1.0m	09-Jun-22	11-Jul-22	0.0m
A1680	Buildings & Enclosures - S/M Construction	1.0m	11-Jul-22	10-Aug-22	0.0m
A1340	Mob. - E&I Construction	0.5m	26-Jul-22	10-Aug-22	0.0m
A1320	Electrical & Controls to Tie-Point - E&I Construction	2.5m	10-Aug-22	25-Oct-22	0.0m
A1480	Install Remaining Electrical & Controls - E&I Construction	1.0m	26-Oct-22	01-Dec-22	0.0m
A1460	Demob. - E&I Construction	0.5m	01-Dec-22	16-Dec-22	0.0m
A1370	Startup & Commissioning	1.7m	16-Dec-22	14-Feb-23	0.0m
A1380	Initial Operation	0.5m	14-Feb-23	01-Mar-23	0.0m
A1750	Cease Flows to East Ash Pond	0.0m		01-Mar-23*	0.0m



Actual Work | Critical Remaining Work | Summary
Remaining Work | Milestone

AECOM

Appendix D
Certification of Compliance

Certification of Compliance

In accordance with 40 CFR §257.103(f)(1)(iv)(B)(1), I, Angila Retherford, being a qualified representative of Southern Industrial Gas & Electric Company, do hereby certify, to the best of my knowledge, information, and belief, that the F.B. Culley Generating Station is in compliance with all of the requirements of 40 CFR 257 Subpart D – Standards for the Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments. F.B. Culley's CCR Compliance website is up-to-date and contains all the necessary documentation and notification postings.

Angila Retherford

Signed

Angila Retherford

Printed Name

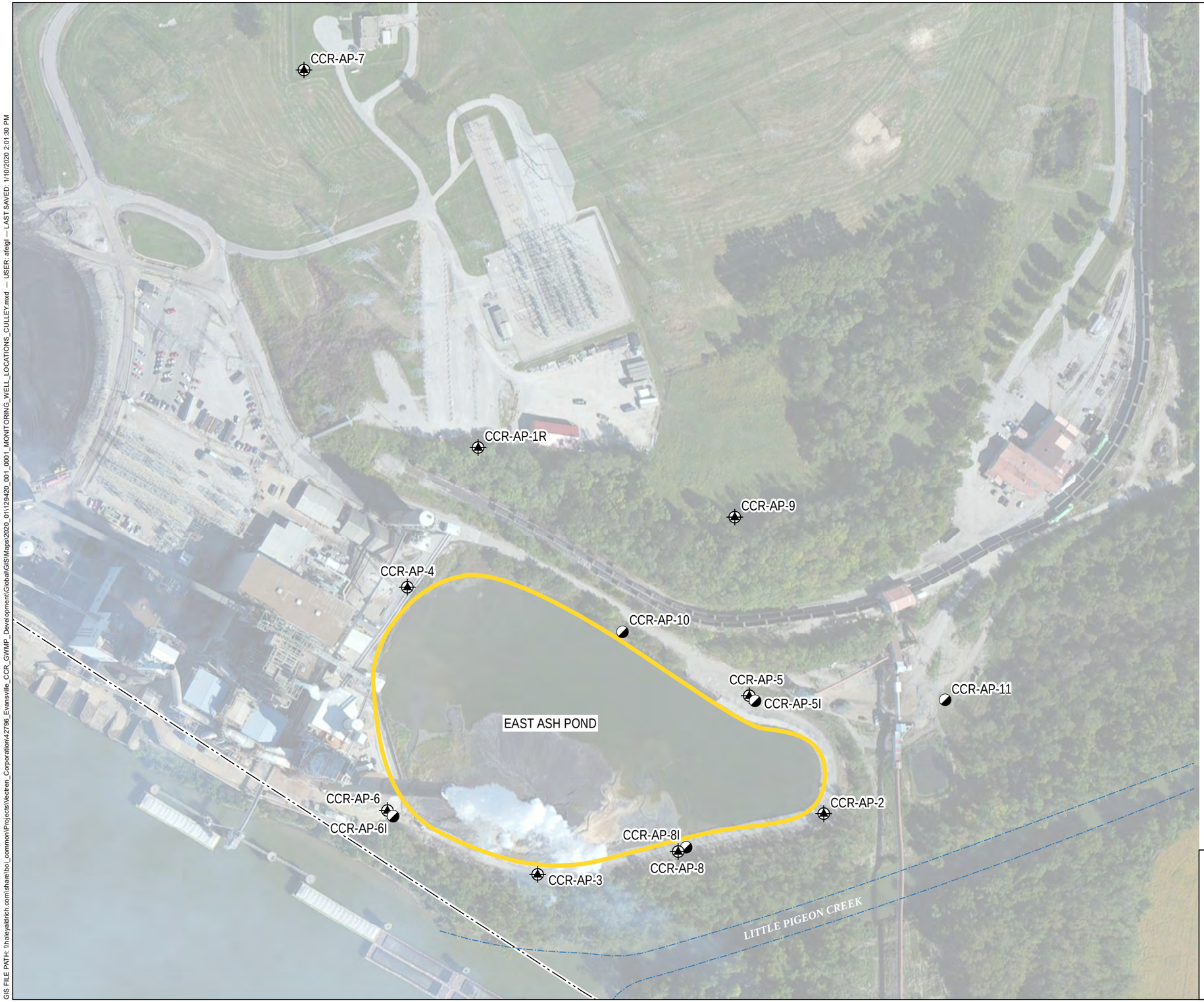
VP, Environmental & Corp Resp

Title

11/23/20

Date

Appendix E
Groundwater Monitoring Well Location



LEGEND

CCR-AP-11 — MONITORING WELL

CCR-AP-6I — NATURE AND EXTENT MONITORING WELL

APPROXIMATE UNIT BOUNDARY

APPROXIMATE PROPERTY BOUNDARY

NOTES

1. ALL LOCATIONS ARE APPROXIMATE
2. CCR COAL COMBUSTION RESIDUALS
3. AERIAL IMAGERY SOURCE: ESRI

N

0 220 440

SCALE IN FEET

HALEY ALDRICH

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
F.B. CULLEY GENERATING STATION
NEWBURGH, INDIANA

GROUNDWATER MONITORING WELL LOCATIONS

JANUARY 2020

FIGURE 1

GIS FILE PATH: \\haleyaldrich.com\share\bos_common\Projects\Western_Corporation\42796_Evansville_CCR_GWMP_Development\Global\GIS\Maps\2020_01\129420_001_0001_MONITORING_WELL_LOCATIONS_CULLEY.mxd — USER: afeigl — LAST SAVED: 1/10/2020 2:01:30 PM

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 110
DOE Order No. 202-24-1

Department of Energy
Washington, DC 20585

Order No. 202-24-1

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Florida due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On October 9, 2024, Duke Energy Florida, LLC (Duke), an investor-owned utility, whose service territory includes electric customers in Florida, filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system." As of 4 PM EDT on October 9, 2024, Hurricane Milton is a Category 3 storm forecast to remain a major hurricane and expand in size as it approaches the west coast of Florida. The center is likely to make landfall along the west-central coast of Florida during the night on Wednesday, October 9, 2024, or in the early morning on Thursday, October 10, 2024, and move east-northeastward across central Florida through October 10, 2024. Hurricane Milton follows the landfall of Hurricane Helene in Florida on September 26, 2024, which resulted in over 230 deaths in the southeast United States and for which recovery and restoration efforts remain ongoing. As of 5:00 PM EDT on October 9, 2024, Florida was experiencing 118,000 outages related to the approaching Hurricane Milton, with the number increasing rapidly.

On October 7, 2024, President Biden declared that an emergency exists in the State of Florida and ordered Federal assistance to supplement State, tribal, and local response efforts due to the emergency conditions resulting from Hurricane Milton beginning on October 5, 2024, and continuing.

Duke has indicated that its service territory is being impacted by Hurricane Milton. Duke expects that Hurricane Milton will cause hurricane-force-gusts across the St. Petersburg/Tampa metropolitan region at the height of the storm overnight into early Thursday, October 10, 2024. Elsewhere, strong tropical-storm to near hurricane-force-gusts are projected to impact highly populated zones along the I-4 corridor served by Duke. The combination of damaging winds,

torrential rain and subsequent flooding, storm surge at the coast, and possible tornadoes, will result in major power outages, damaging distribution and transmission infrastructure, and threaten several generation stations along the path. Application at 1.

While many generating units in the Duke service territory continue to function adequately under these stressed conditions, several of Duke's generating units are expected to be forced to shut down due to facility limits on wind speeds and storm surge, as well as staffing issues caused by mandatory evacuations. Additionally, Crystal River Units 4 and 5 remain in forced outage from storm surge impacts from Hurricane Helene. Specifically, approximately 4,000 MW of generating units are currently offline and will remain offline during Hurricane Milton. Application at 2.

Additionally, several units at Citrus Combined Cycle, the subject of this Order, may be forced offline by conditions in its Title V operating permit. With projected outages and low demand, in order to keep the Citrus Combined Cycle units online, they would potentially need to operate at low load for an extended period of time, which could result in noncompliance with its Title V permit. If these units are brought offline due to these compliance requirements, they may not be able ramp up quickly enough to meet demand as load increases following power restoration, particularly in light of the amount of generation predicted to be offline due to hurricane impacts. For example, ramp-up times from a cold start could be eight or nine hours, and could be further delayed by pre-generation start-up checks. Additionally, shutting down also increases the risk or equipment failure, as well as the risk of water intrusion due to thermal and pressure gradient changes. If equipment fails or is damaged by Hurricane Milton, units may not be able to start without additional maintenance. In that case, Duke may have to declare an Energy Emergency Alert (EEA) Level 3 and institute rotating load shed. Such impacts would hinder post-hurricane restoration and recovery activities and overall grid reliability. Although Duke would attempt to mitigate such impacts through alternative generation as well as power purchases, it is unknown what will be available following Hurricane Milton and whether the necessary transmission infrastructure will remain for this purpose. Application at 2.

The Florida Reliability Coordinating Council, Inc. (FRCC), the Reliability Coordinator for Duke's service territory and others, filed a formal endorsement on October 9, 2024, of Duke's Application, specifically the need to continue operation of the Specified Resources in Application Exhibit A at low load operation to help reduce the likelihood of any firm load shedding during the hurricane event. FRCC Letter at 1. The endorsement explains:

> It is the FRCC's firm opinion that granting this relief request will provide an immeasurable benefit to this mission and in turn, the public served by the FRCC and its member entities. Allowing this relief will not only serve the reliability of [Duke's] service territory, but also the many local electric cooperatives served by [Duke] and other interconnected electric utilities and service providers.

FRCC Letter at 2.

Description of Mitigation Measures

Duke has indicated that it will attempt to keep the Citrus Combined Cycle units operating at a load level compliant with its Title V permit whenever possible, including attempting to sell power to keep load higher. Duke anticipates needing to continue these efforts through October 13, 2024. Subject to the exceptions included in this Order, Duke has committed to continuing to take such actions, including attempting to sell power, before operating any units in a manner that will result in a conflict with a requirement of any federal, state, or local environmental statute or regulation, including requirements in permits issued pursuant to such laws or regulations.

Request for Order

Duke requests that the Secretary issue an order immediately, effective October 9, 2024, through 00:00 EDT on October 13, 2024, authorizing "continued operation of the Specified Resources" in the Duke service territory. Application at 3. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-24-1 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of Duke to ensure maximum reliability on its system, and the ability of Duke to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current extreme weather event and its aftermath threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the State of Florida and within the region demonstrate the need for the Specified Resources to contribute to system reliability.
- Duke's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the load resulting from the extreme weather event and its aftermath.

In line with the anticipated circumstances precipitated by Hurricane Milton, this Order is limited to the period beginning with the issuance of this Order on October 9, 2024, through 00:00 EDT on October 13, 2024. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. Duke anticipates that this Order may result in exceedance of emissions of Volatile Organic Compounds (VOC), specifically formaldehyde. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on October 9, 2024, to 00:00 EDT on October 13, 2024, in the event that Duke determines that generation from the Specified Resources is necessary to meet the electricity demand that Duke anticipates in Florida during and immediately following this event, I direct Duke to dispatch such unit or units and to order their operation only as needed to maintain the necessary expected generation in the Duke service territory. Specified Resources are those generating units set forth on the Order 202-24-1 Resource List, which the Department shall post on www.energy.gov. Duke is directed to provide updates, if any, to Exhibit A to its Application with the anticipated category of environmental impact(s) (i.e., formaldehyde, sulfur dioxide, nitrogen oxide, mercury, carbon monoxide emissions, wastewater release, other air pollutants) by 21:00 EDT on October 10, 2024.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke for maintaining grid reliability to avoid adverse health and safety impacts to customers from shedding firm customer load. Duke shall exhaust all possible measures to run the Specified Units at a load level in compliance with permit requirements, including attempting to sell power. Duke shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. Duke shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By October 20, 2024, Duke shall report all dates between October 9, 2024, and October 13, 2024, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting

limits, including formaldehyde, sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. Duke shall submit a final report by November 20, 2024, with any revisions to the information reported on October 20, 2024. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, formaldehyde, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g. "Generator #1; October 10, 2024; 4 hours; 04:00-08:00 EDT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, Duke shall provide information to the Department quantifying the net revenue associated with generation in excess of environmental limits accruing to the Specified Resources in connection with any order issued by the Department pursuant to Section 202(c) of the Federal Power Act.

E. Duke shall take reasonable measures to inform affected communities where all Specified Resources operate that Duke has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows Duke to do. At a minimum, Duke shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of any Specified Resource covered by this Order. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by Duke with respect to the extreme weather event and will include a reference to the website posting required by the preceding sentence for further information. Duke shall describe the actions taken to comply with this paragraph in the

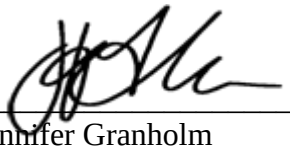
reports delivered to the Department pursuant to paragraph D above.

F. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Duke shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on Sunday, October 13, 2024, with the exception of the reporting requirements in paragraph D. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 8:00 PM Eastern Daylight Time on this 9th day of October 2024.



Jennifer Granholm
Secretary of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

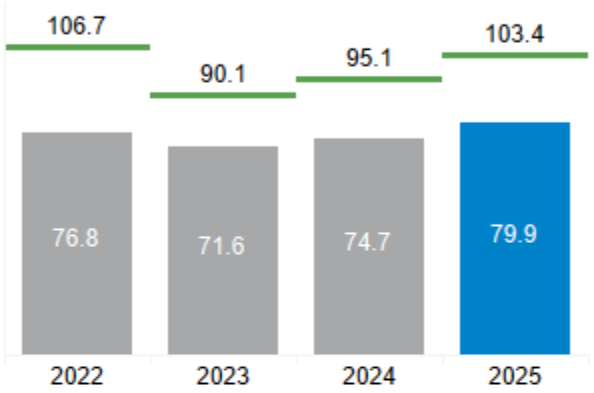
Exhibit 111
MISO December Operations Report

MISO Monthly Operations Report

December 2025

Reliability, markets and operational functions performed as expected in December

AVERAGE & PEAK LOAD (GW)



SYSTEM-WIDE LOAD PEAK

103 GW

December 15, Hour Ending (HE) 9

SOLAR PEAK

11.2 GW

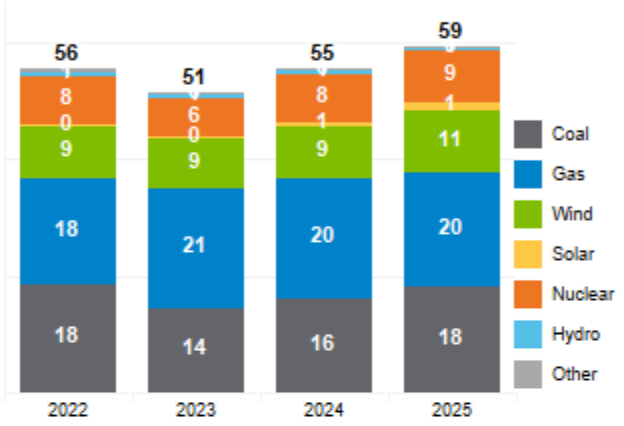
Dec 15, 2025, HE 12

WIND PEAK

26.1 GW

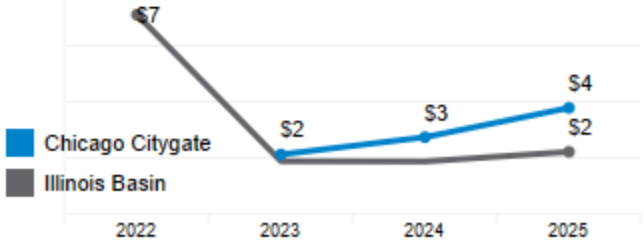
Dec 28, 2025, HE 23

ENERGY FUEL MIX (TWh)

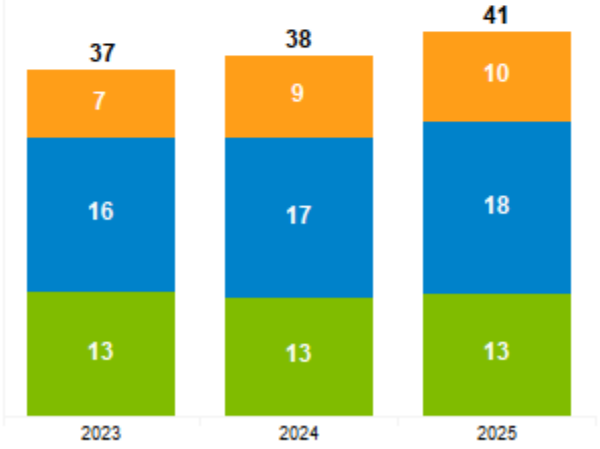


REAL-TIME LMP ($/MWh)

AVERAGE FUEL PRICE ($MMBtu)



AVERAGE DAILY GENERATION OUTAGE (GW)



KEY OPERATING DECLARATIONS

DECEMBER 2025

	1	2	3	4	5	6
7	8	9	10	11	12	13
14	15	16	17	18	19	20
21	22	23	24	25	26	27
28	29	30	31			

12/03 System: *Geomagnetic Disturbance Alert*
12/04 System: *Geomagnetic Disturbance Warning*
12/13 System: *Cold Weather Alert*
12/20 System: *System Status Level 1*
12/28 System: *Severe Weather Alert*
12/28-29 North: *Severe Weather Alert*

- *All-Time Solar Peak: 14.5 GW on Sept 7, 2025, HE 11*
- *All-Time Wind Peak: 26.6 GW on Jan 13, 2025, HE 20*
- *All-Time Load Peak: 127.1 GW on Jul 20, 2011, HE17*

Derated
Unplanned
Planned

Awareness and Weather
Alerts and Warnings
Reliability Actions and Events

Dashboard

Metric	Chart	Dec 2025	Nov 25	Oct '25	Sept '25	Metric	Chart	Dec 2025	Nov 25	Oct '25	Sept '25
Market Efficiency Metric	D	▼	●	●	●	Unit Commitment Efficiency	H	●	●	●	●
Percentage Price Deviation	A	●	●	●	▼	Day Ahead Wind Generation Forecast Error	K	●	●	●	●
Monthly Average Gross Virtual Profitability	B	●	●	●	●	Day-Ahead Solar Generation Forecast Error	T	●	●	●	●
FTR Funding	C	●	●	●	●	Tie Line Error	L	●	●	●	●
RSG per MWh to Energy Price	E	■	●	■	●	Control Performance – BAAL	M	●	●	●	●
Day Ahead Mid-Term Load Forecast	F	●	●	●	●	Control Performance – CPS1 and CPS1 12-month rolling	N	●	●	●	●
Short-Term Load Forecast	G	●	●	●	●	ARS Deployment	P	●	●	●	●
Real-Time Obligation fulfilled by Day-Ahead Supply at the Peak Hour	I	●	●	●	●						
System Impact Study Performance	Q	●	●	●	●	Settlement Disputes	S	●	●	●	●

● *Expected* ■ *Concern/Monitor* ▼ *Review*

Note: Dashboard metric criteria are reviewed and revised each year and is included in the Appendix.

Two metrics fell outside of the expected range for this month

Metric	Expected Criteria	Actual	Status	Comments
RSG per MWh to Energy Price	<=0.38%	0.42%	Monitor	$3.9M paid to resources for Day-Ahead Voltage and Local Reliability commitments due to outages in the South. $0.6M paid to higher priced resources to cover underperforming units and increased load in Real-Time.
Market Funding Efficiency	>=95%	93.8%	Review	Excess Congestion Fund (ECF) settled at around a $12M shortfall for the month of December. ECF performance is reflective of the cumulative impact of several high ECF funding constraints and increased congestion. The high impact ECF constraints were driven by incorrect constraint forecasts, outage volatility, and lack of congestion predictions on the Seams. Day-Ahead Congestion exceeded $262M, with FTR Funding Shortfall nearing $40M—historically high. Key drivers include incorrect outage forecasts and elevated FTR flows. Alignment improvements expected in January, though topology gaps remain a risk.

Appendix

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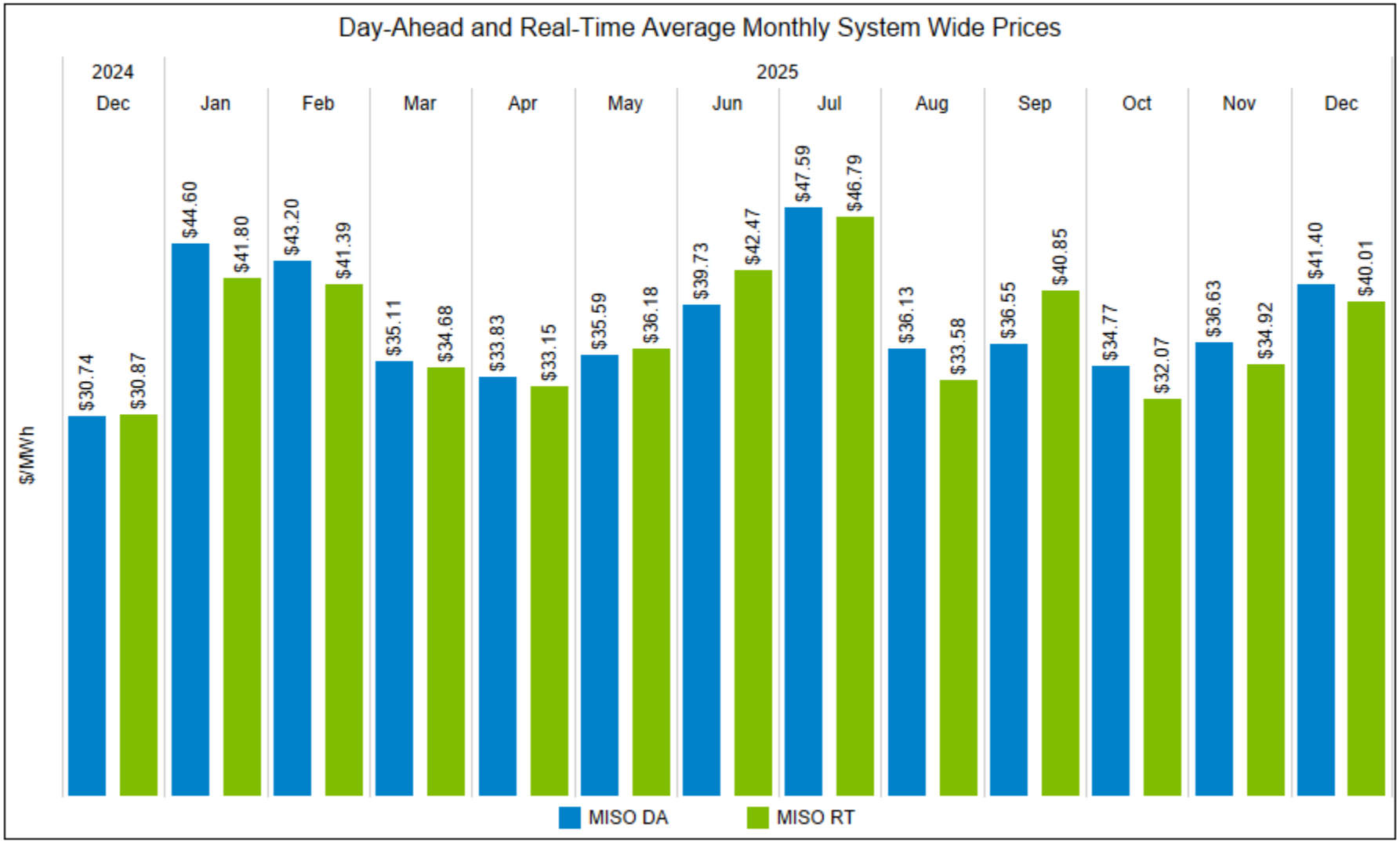
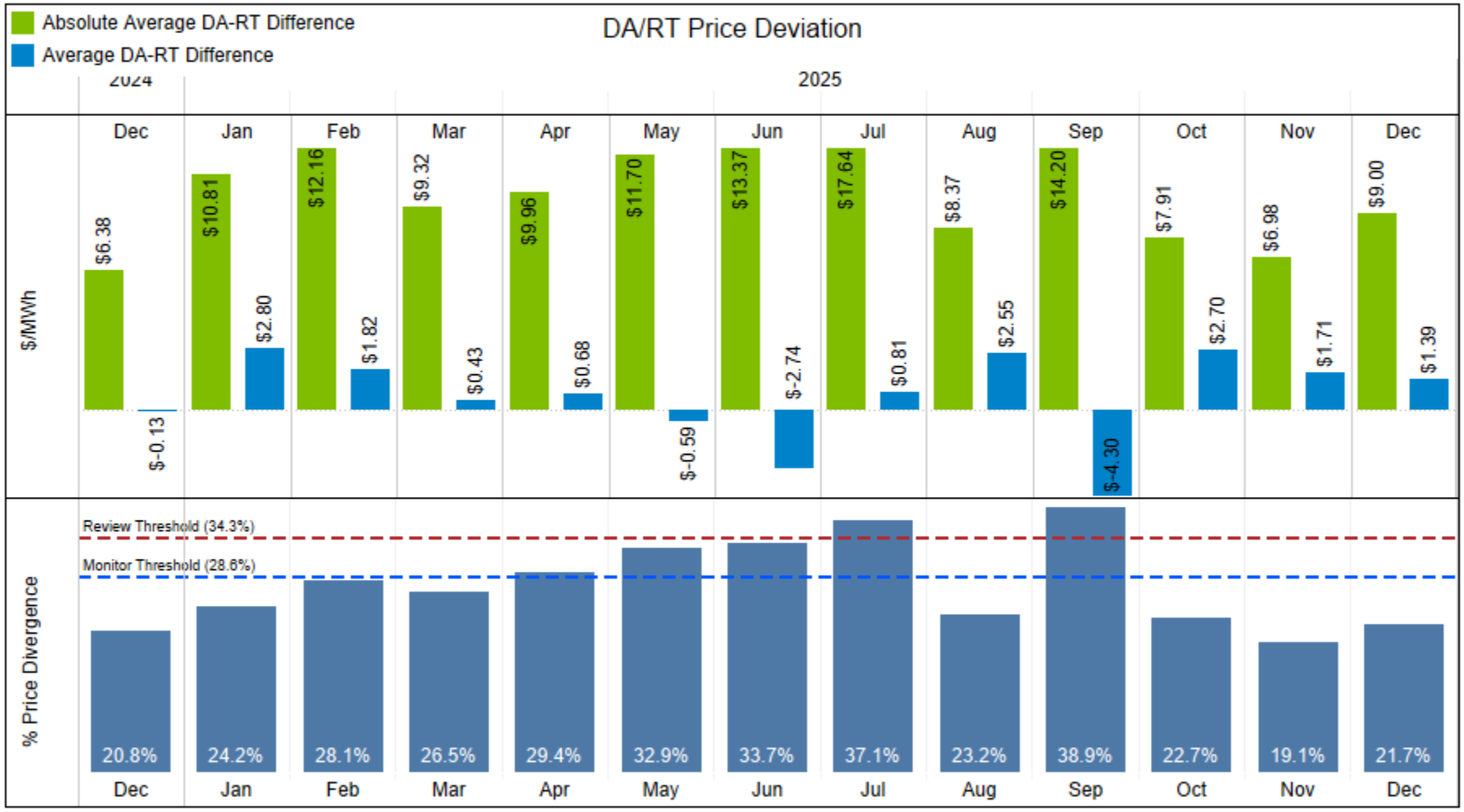
MISO System-wide Day-Ahead and Real-Time Locational Marginal Pricing



Note: MISO System-Wide price is based on the monthly hourly average of the active hubs
Source: MISO Market and Operations Analytics Department

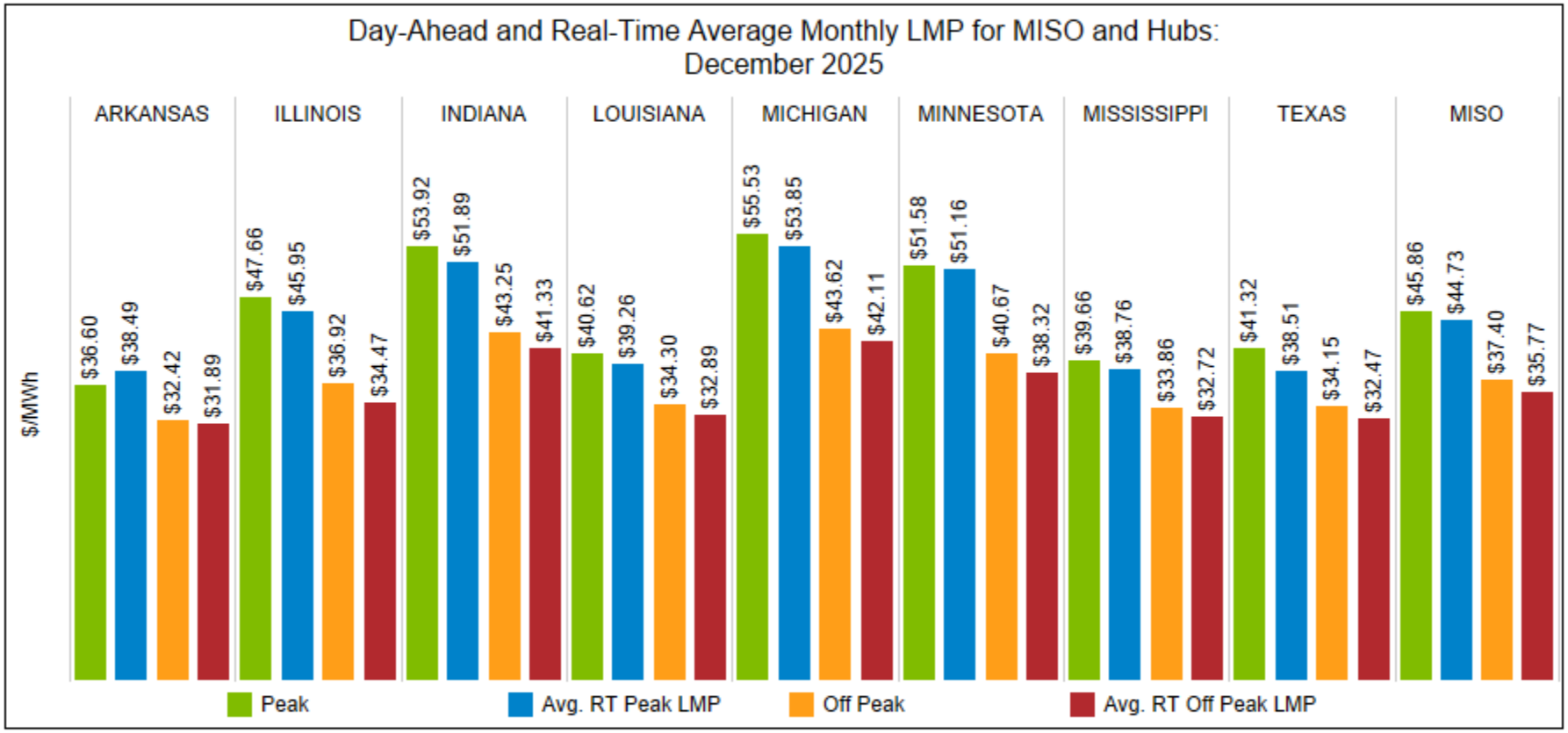
Price Convergence: Day-Ahead and Real-Time Locational Marginal Pricing



**Monthly deviation, expressed as a percent of average DA LMP, is calculated as the average of hourly absolute (DA-RT) price difference divided by the average of hourly DA LMPs for the month*

Note: MISO System-Wide price is based on the monthly hourly average of the active trading hubs
Source: MISO Market and Operations Analytics Department

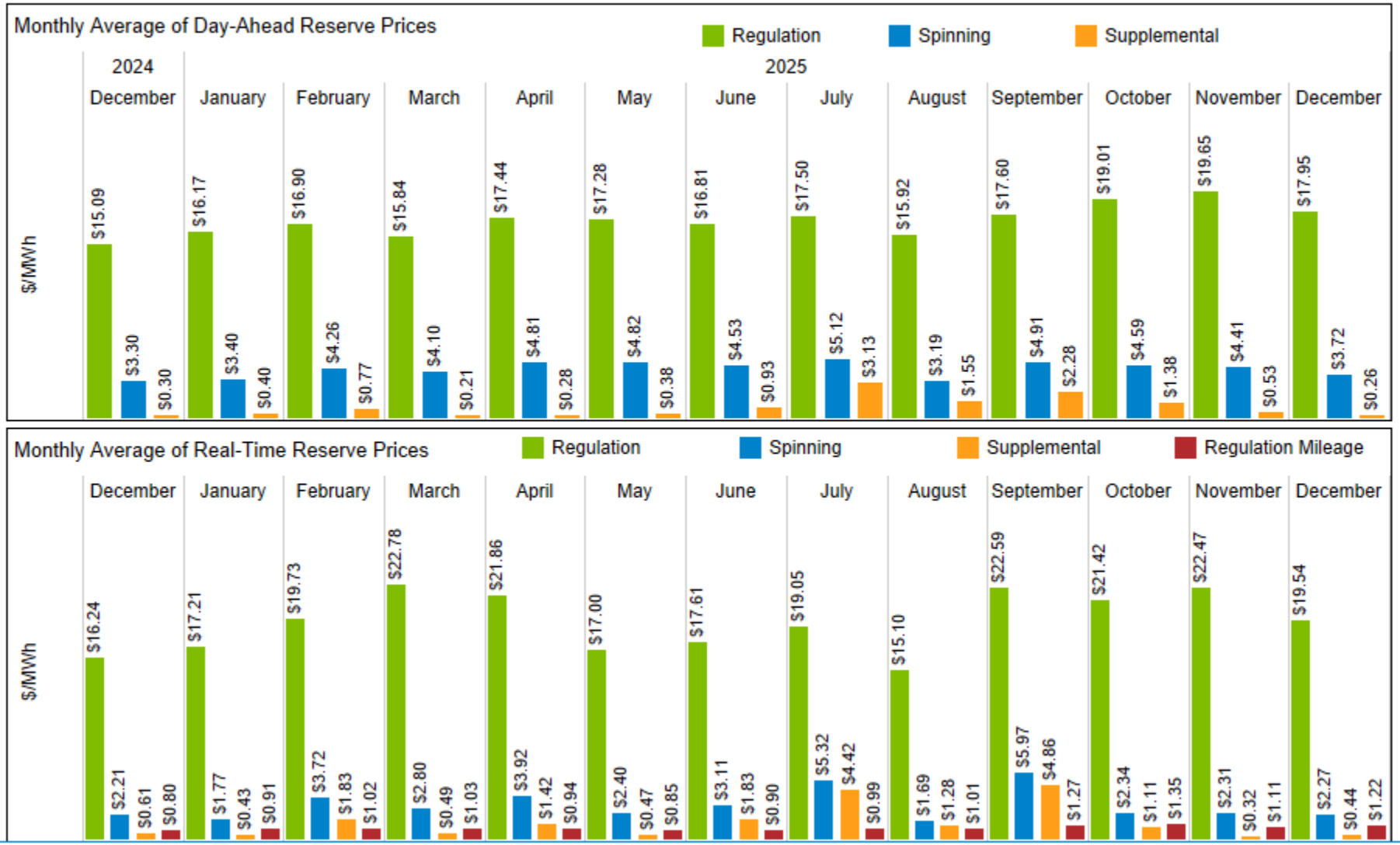
MISO Day-Ahead and Real-Time Hub Locational Marginal Pricing



		ARKANSAS	ILLINOIS	INDIANA	LOUISIANA	MICHIGAN	MINNESOTA	MISSISSIPPI	TEXAS	MISO
Marginal Congestion Component of LMP ($/MWh)	DA Peak	-10.85	-0.98	2.43	-8.49	3.76	2.28	-8.93	-7.85	-3.58
	RT Peak	-6.86	0.05	3.03	-7.67	4.79	4.25	-7.86	-8.47	-2.34
	DA Off Peak	-5.91	-1.66	1.86	-5.40	2.05	0.42	-5.49	-5.40	-2.44
	RT Off Peak	-4.39	-1.68	2.62	-4.56	3.42	0.69	-4.44	-5.04	-1.67

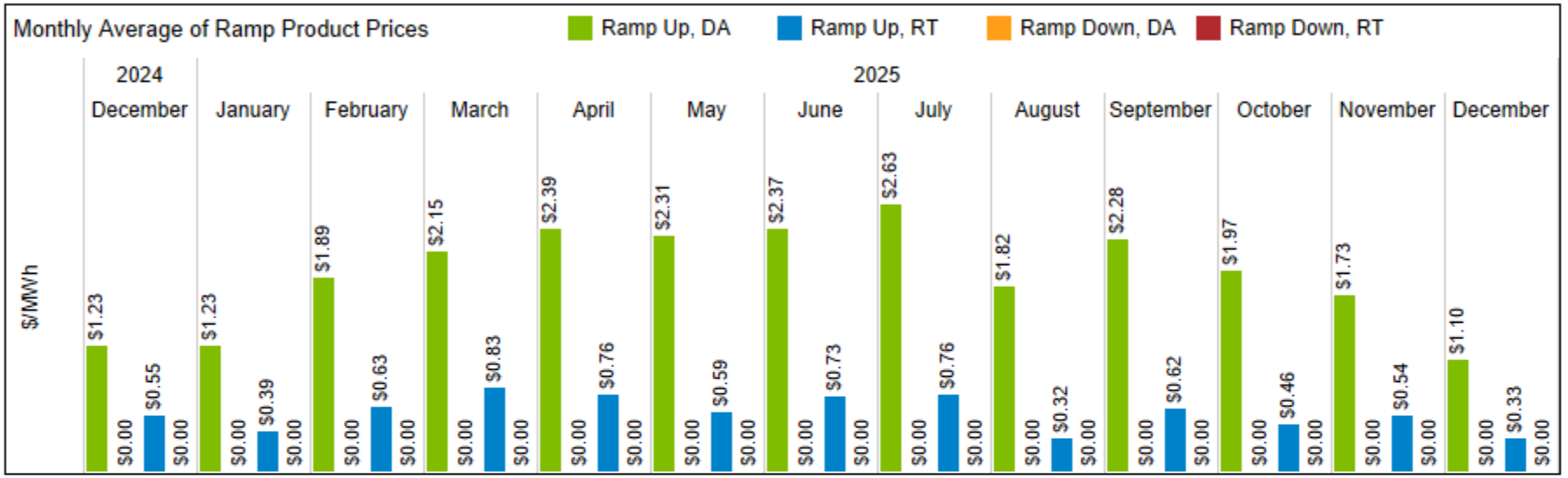
Source: MISO Market and Operations Analytics Department

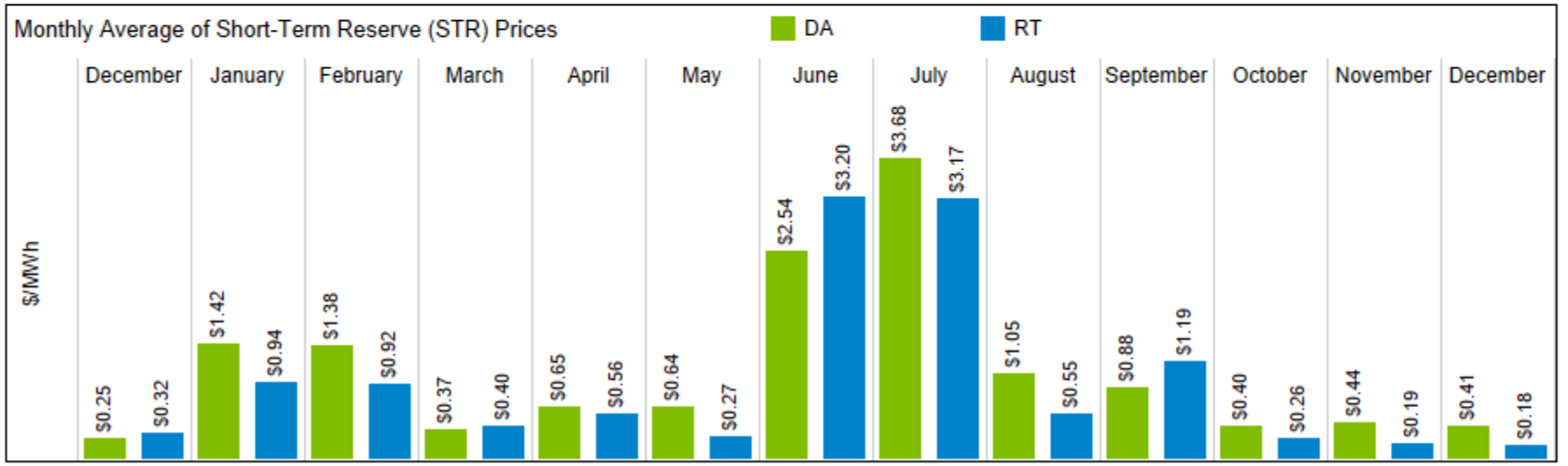
Ancillary Services - Day-Ahead and Real-Time Market Clearing Prices



Source: MISO Market and Operations Analytics Department

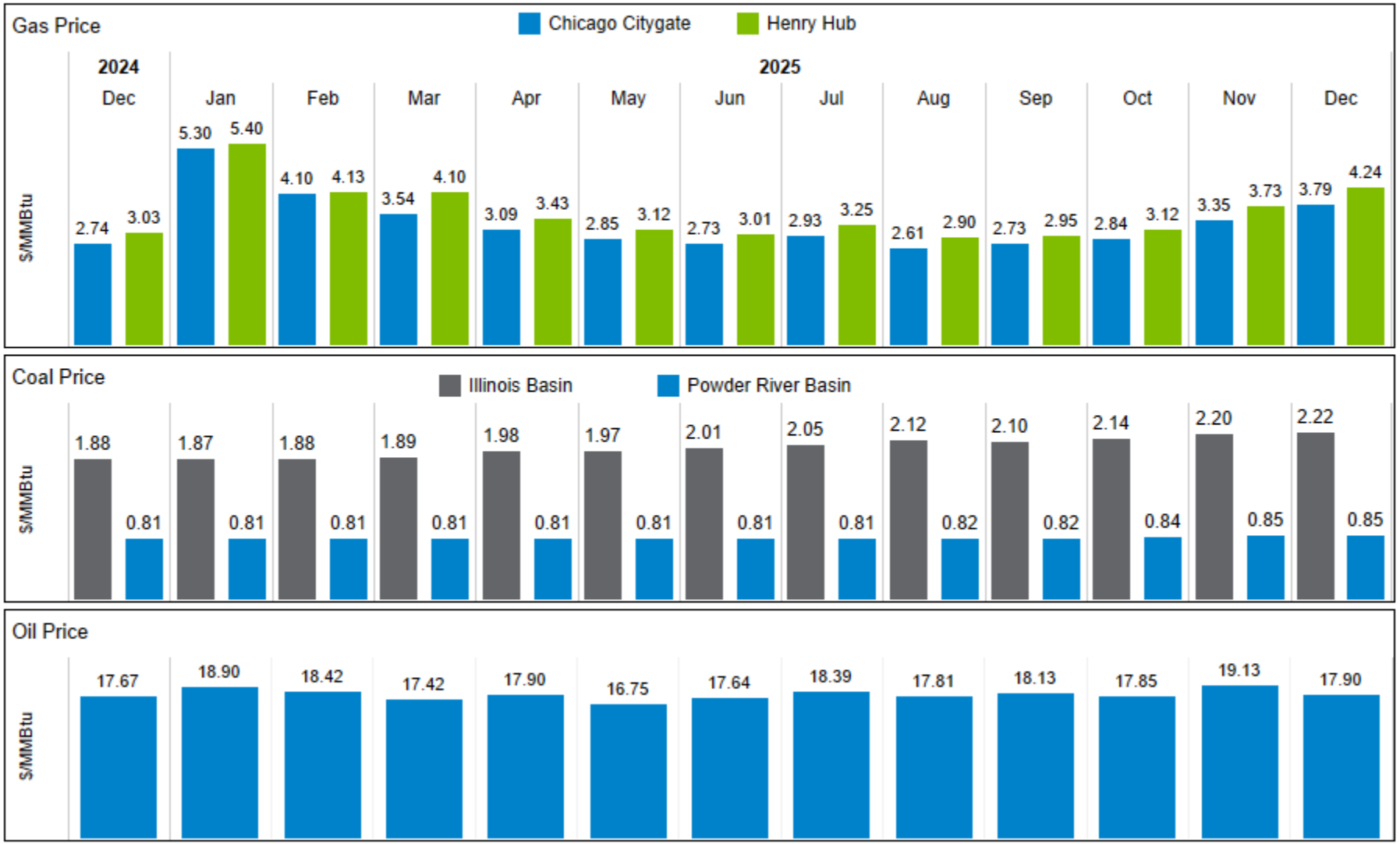
Ancillary Services - Day-Ahead and Real-Time Market Clearing Prices





Source: MISO Market and Operations Analytics Department

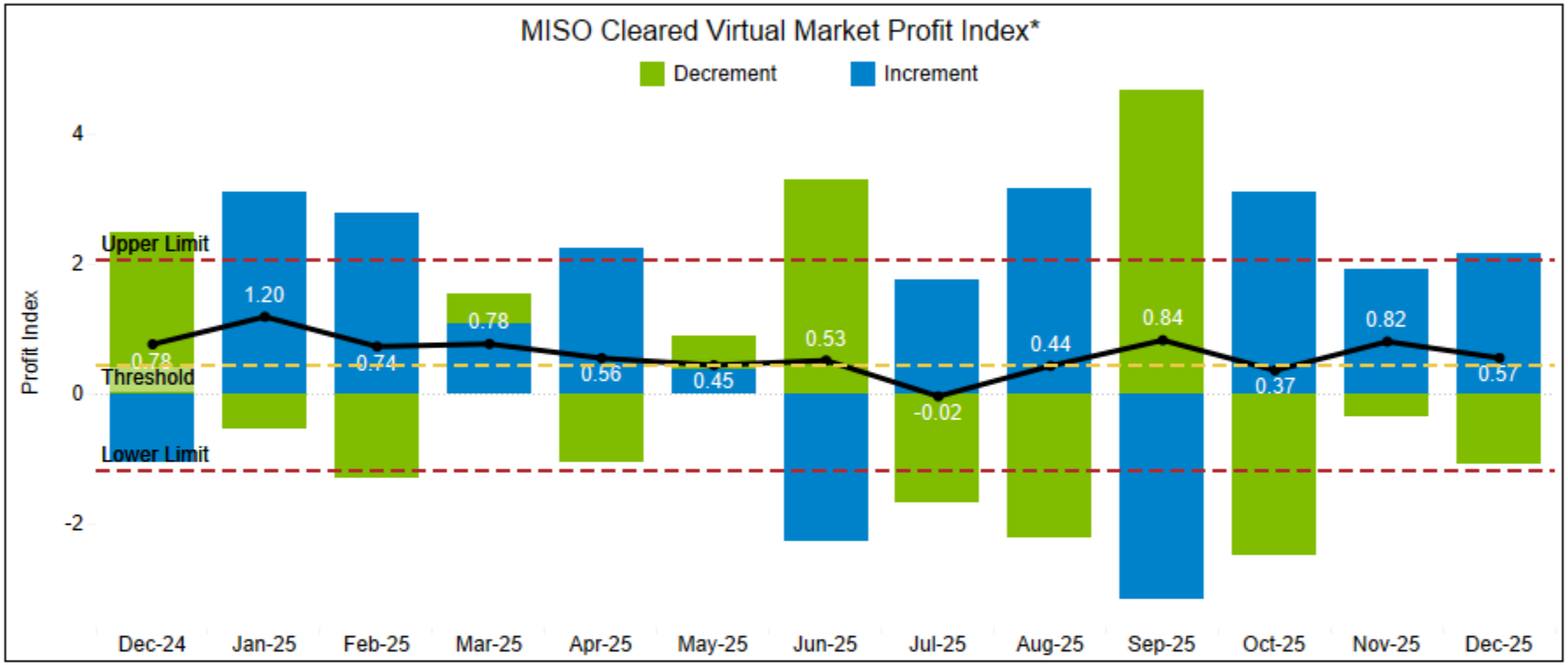
Nominal Fuel Prices



Monthly oil prices are estimates and subject to change upon finalization
Source: EIA

Monthly Average Gross Virtual Profitability

B



Monthly Standard Deviation

Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
1.50	1.81	2.21	1.16	1.15	2.04	1.61	2.64	1.01	1.47	0.75	1.03	1.50

** The virtual profitability market index is defined as the sum of profits/losses for all cleared virtual transactions divided by the volume (MWh) of total cleared transactions.*

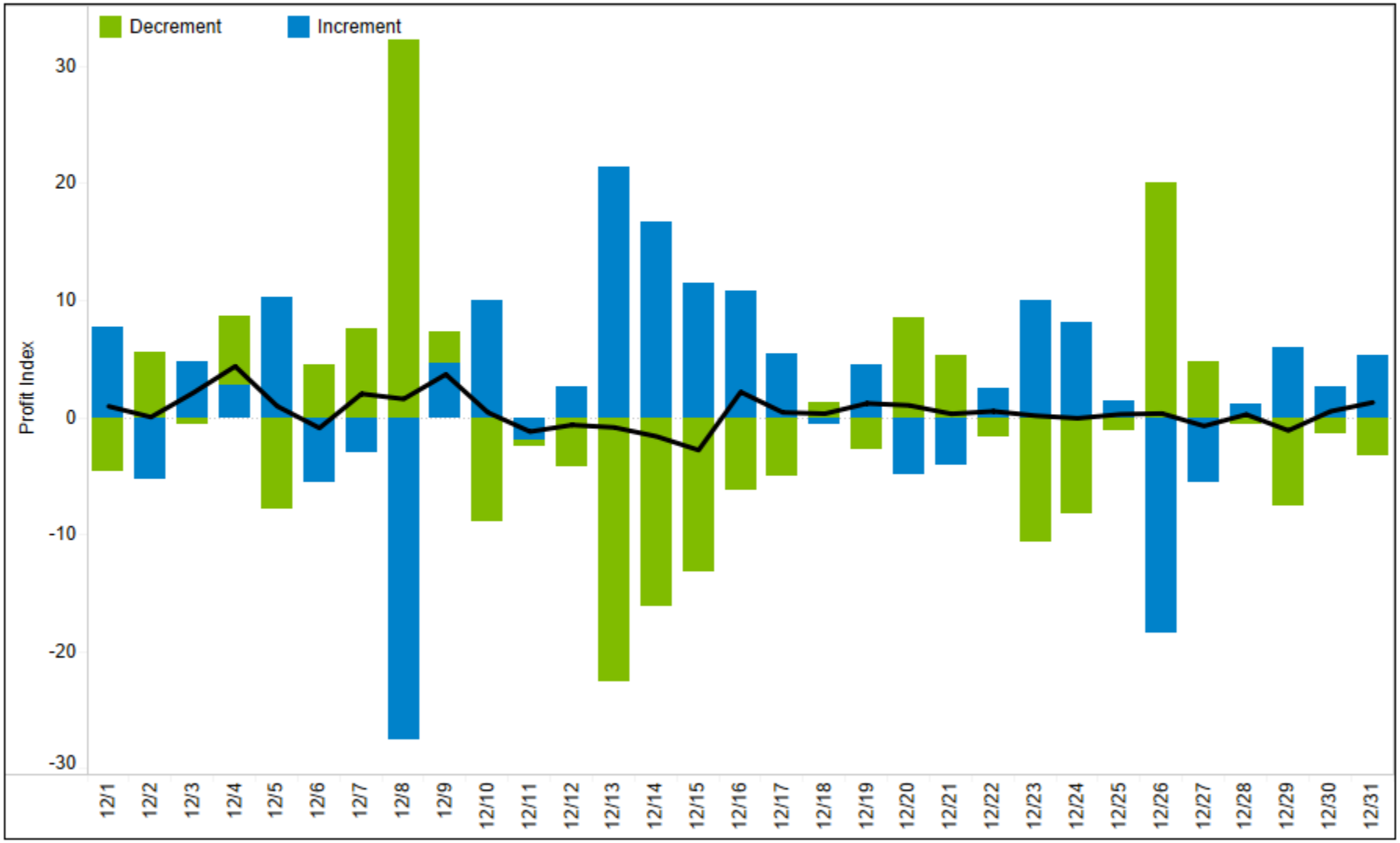
** Virtual profits/losses are calculated by multiplying the cleared virtual MW and the imbalance between RT LMP and DA LMP for a cpnode, then summed across all cpnodes, all hours.*

** Upper Limit is Threshold (average of monthly indices from the previous year) plus Daily Average Standard Deviation for the previous 13 months (current reporting month inclusive)*

** Lower Limit is Threshold (average of monthly indices from the previous year) minus Daily Average Standard Deviation for the previous 13 months (current reporting month inclusi..*

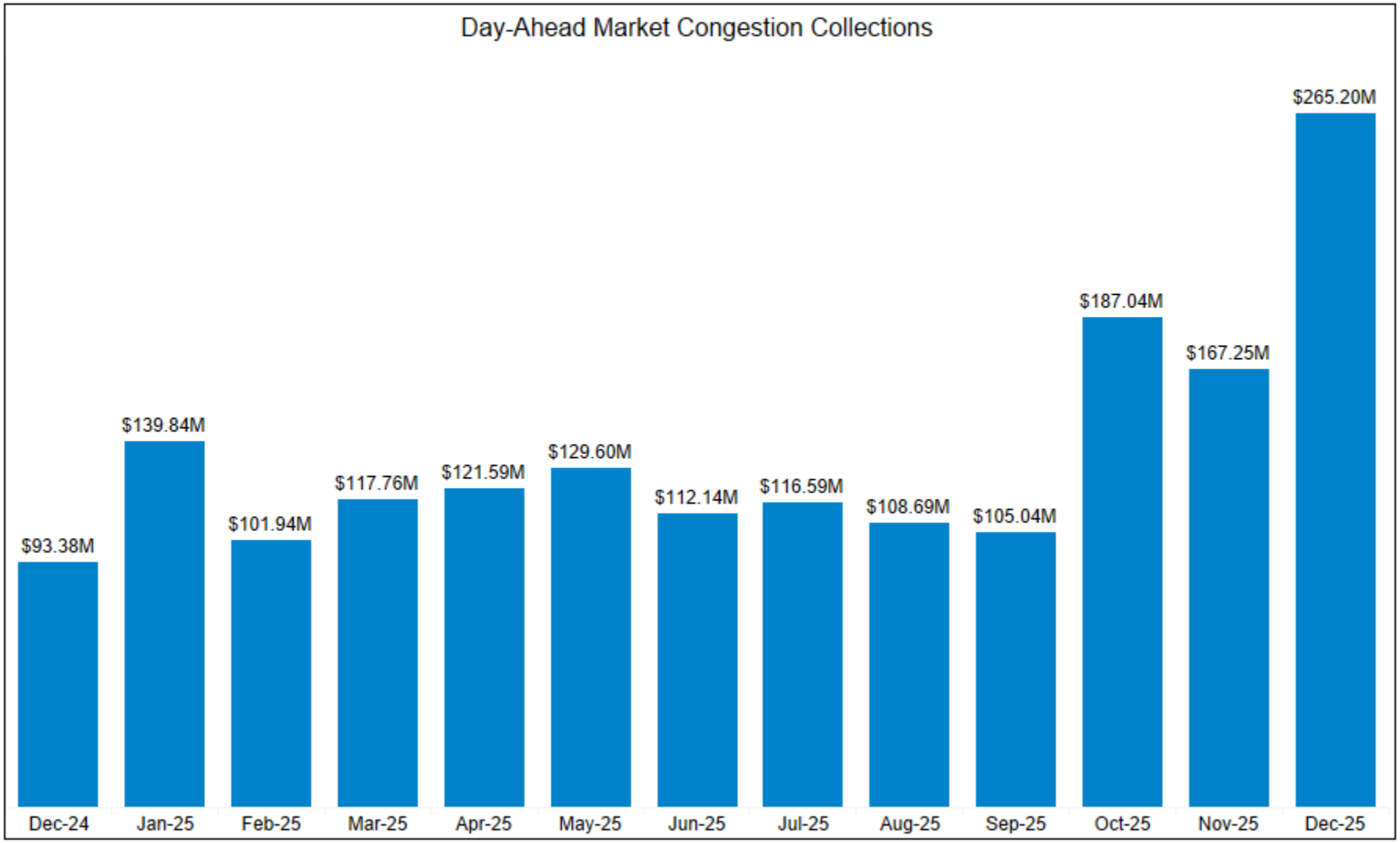
Source: MISO Market and Operations Analytics Department

Daily Gross Cleared Virtual Profitability



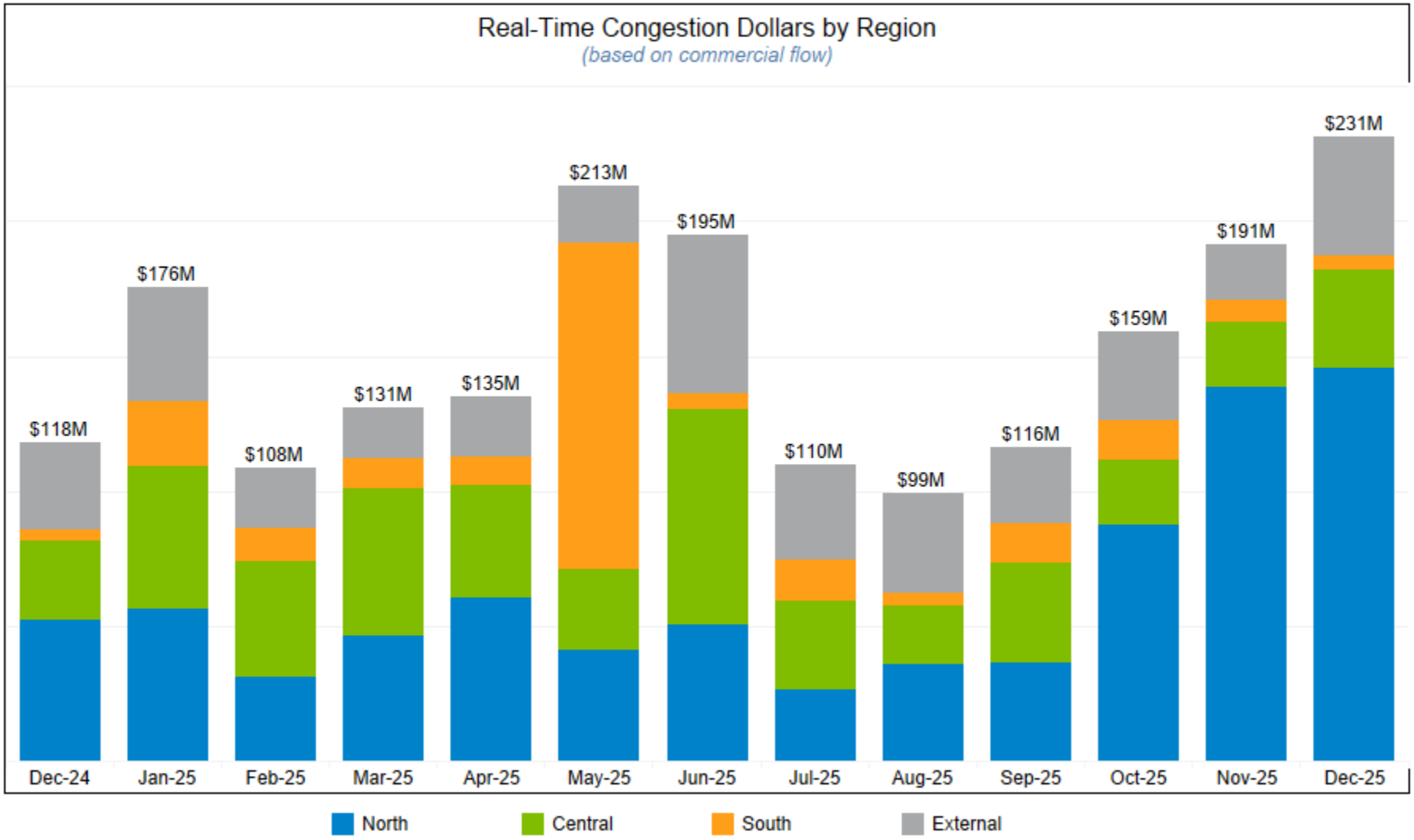
The virtual profitability market index is defined as the sum of profits/losses for all cleared virtual transactions divided by the volume (MWh) of total cleared transactions
Source: MISO Market and Operations Analytics Department

Day-Ahead Congestion Collections



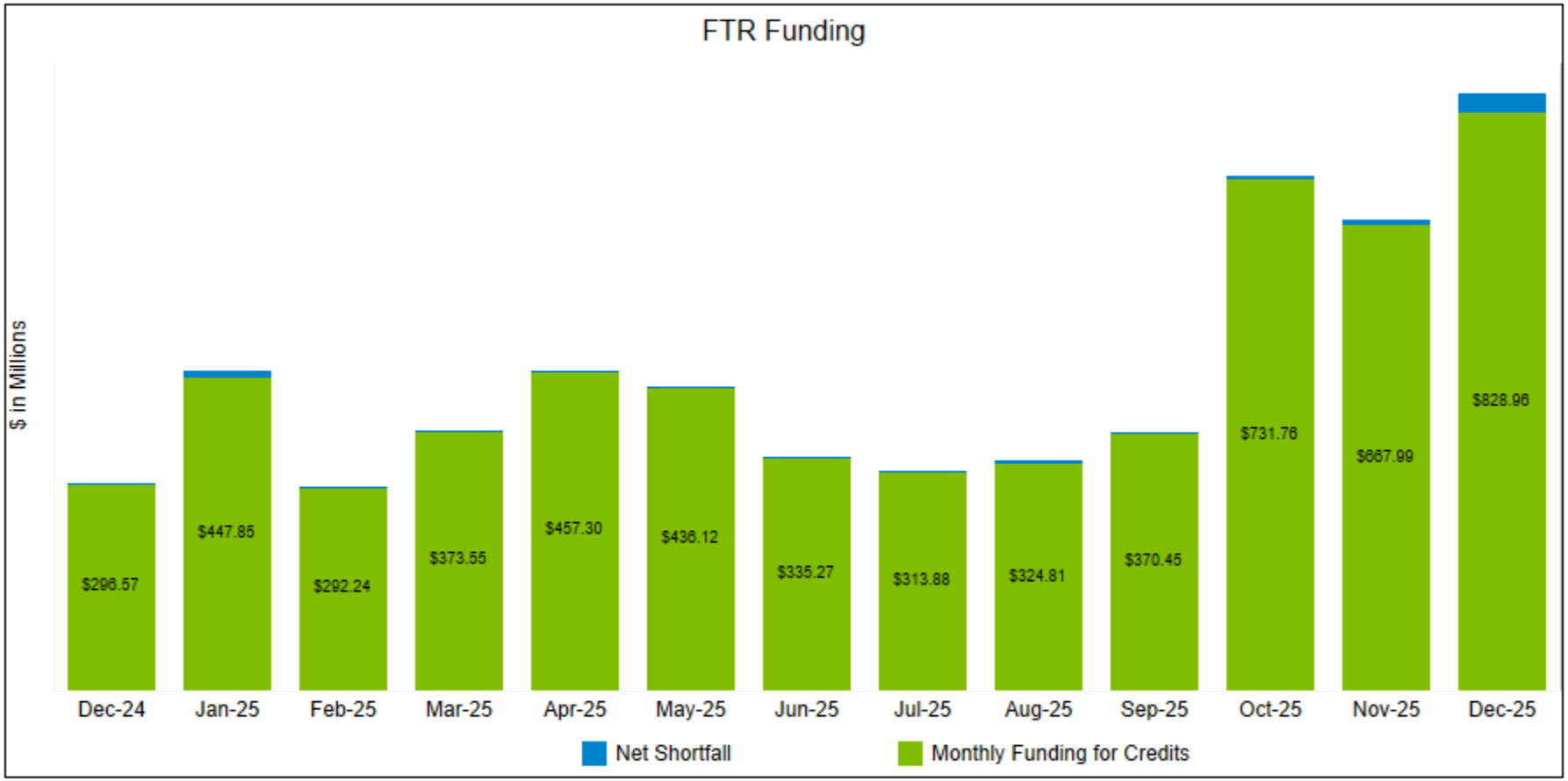
Source: MISO Market and Operations Analytics Department

Real-Time Congestion Dollars by Region



Includes External Constraints
Commercial Flow excludes phase angle regulators and loop flows
Source: MISO Market and Operations Analytics Department

Financial Transmission Rights, Monthly and Rolling Year-to-Date Allocation Funding

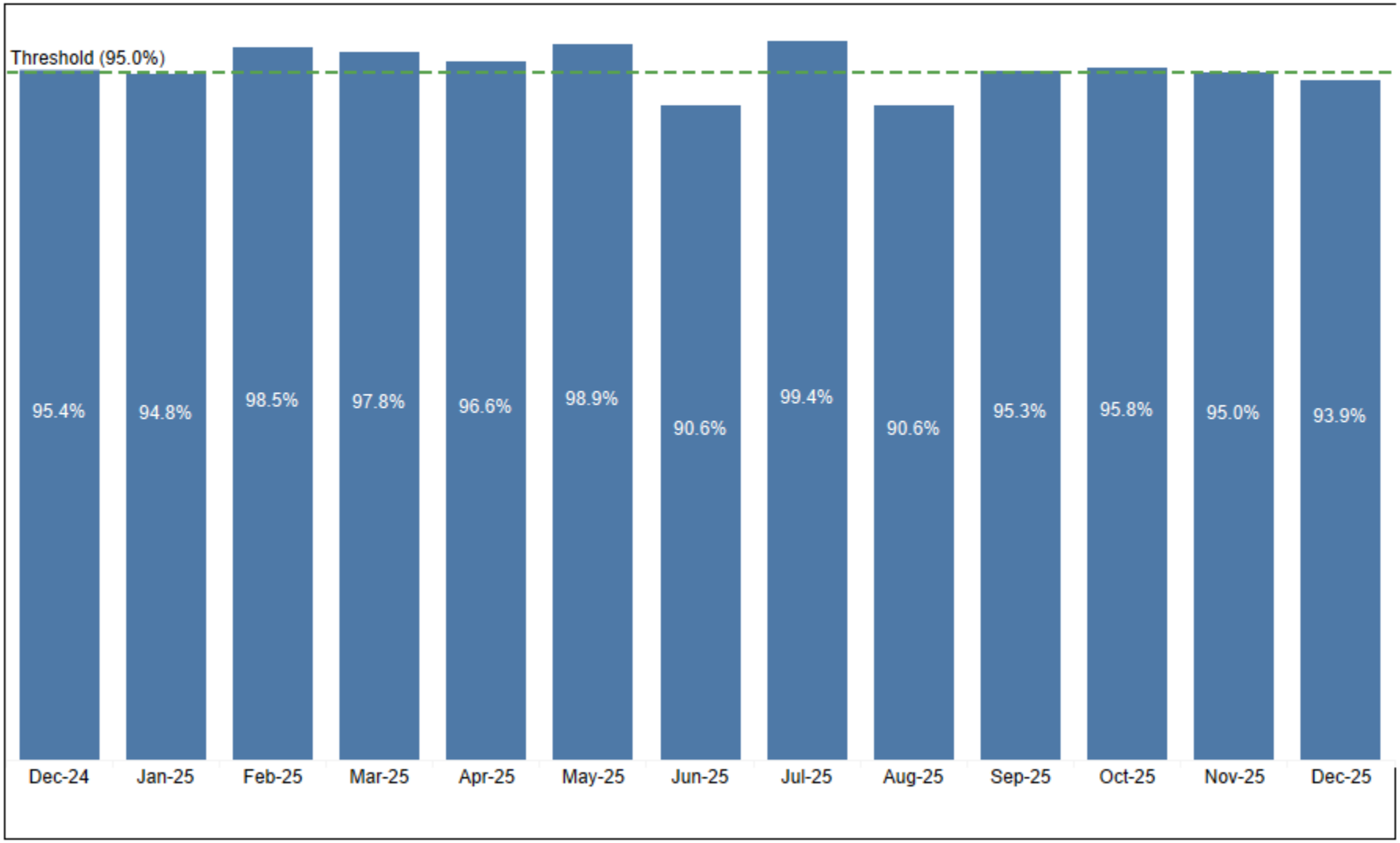


	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
Monthly FTR Allocation (%)	100.0%	97.8%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	98.3%	100.0%	99.0%	99.1%	96.8%
YTD FTR Allocation (%)	98.0%	NA	NA	NA	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

YTD metric is applied beginning April
Values may change due to resettlement
Source: MISO Market ECF Report

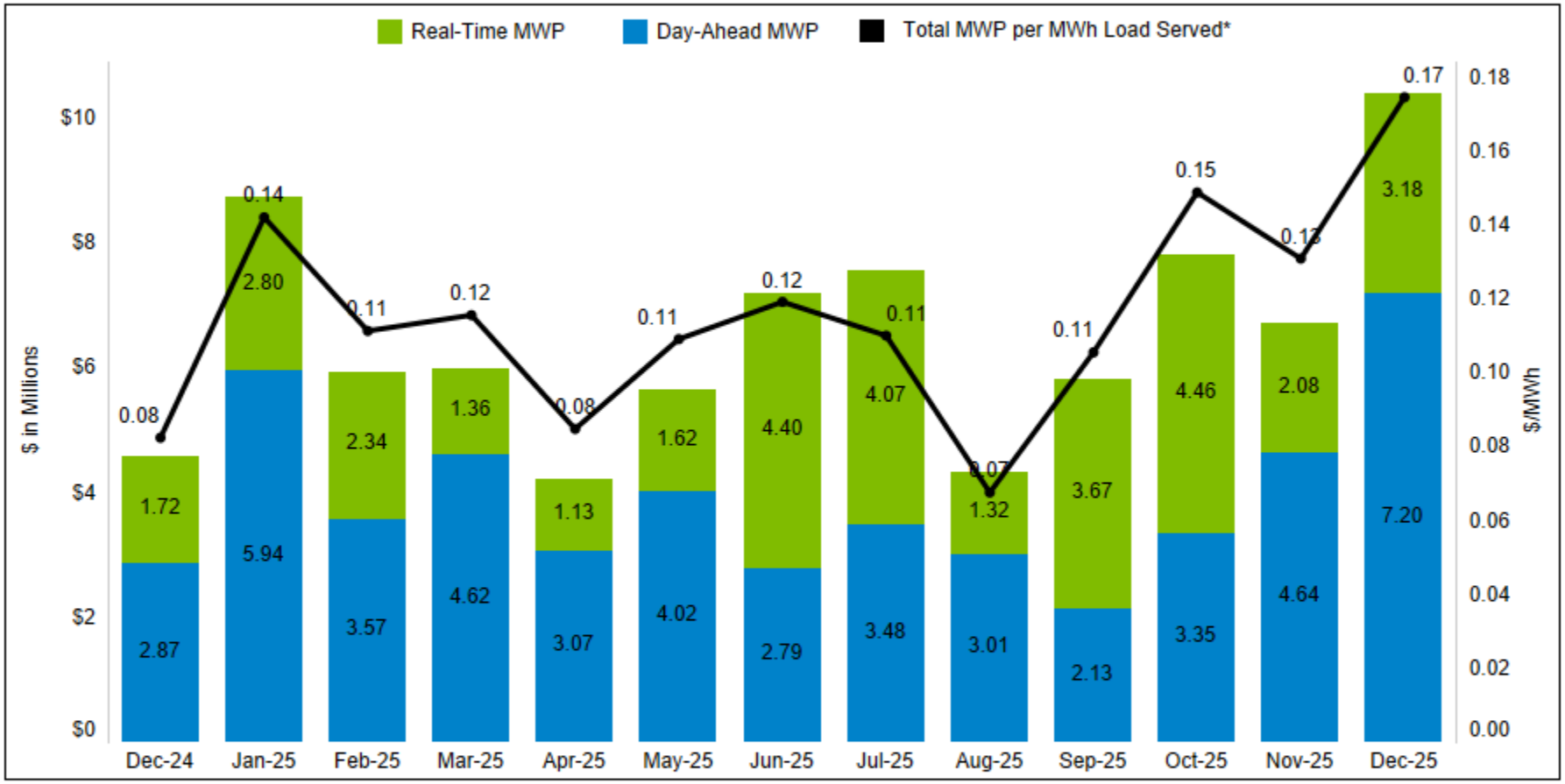
Market Funding Efficiency

D



Values may change due to resettlement
Source: MISO Market ECF Report

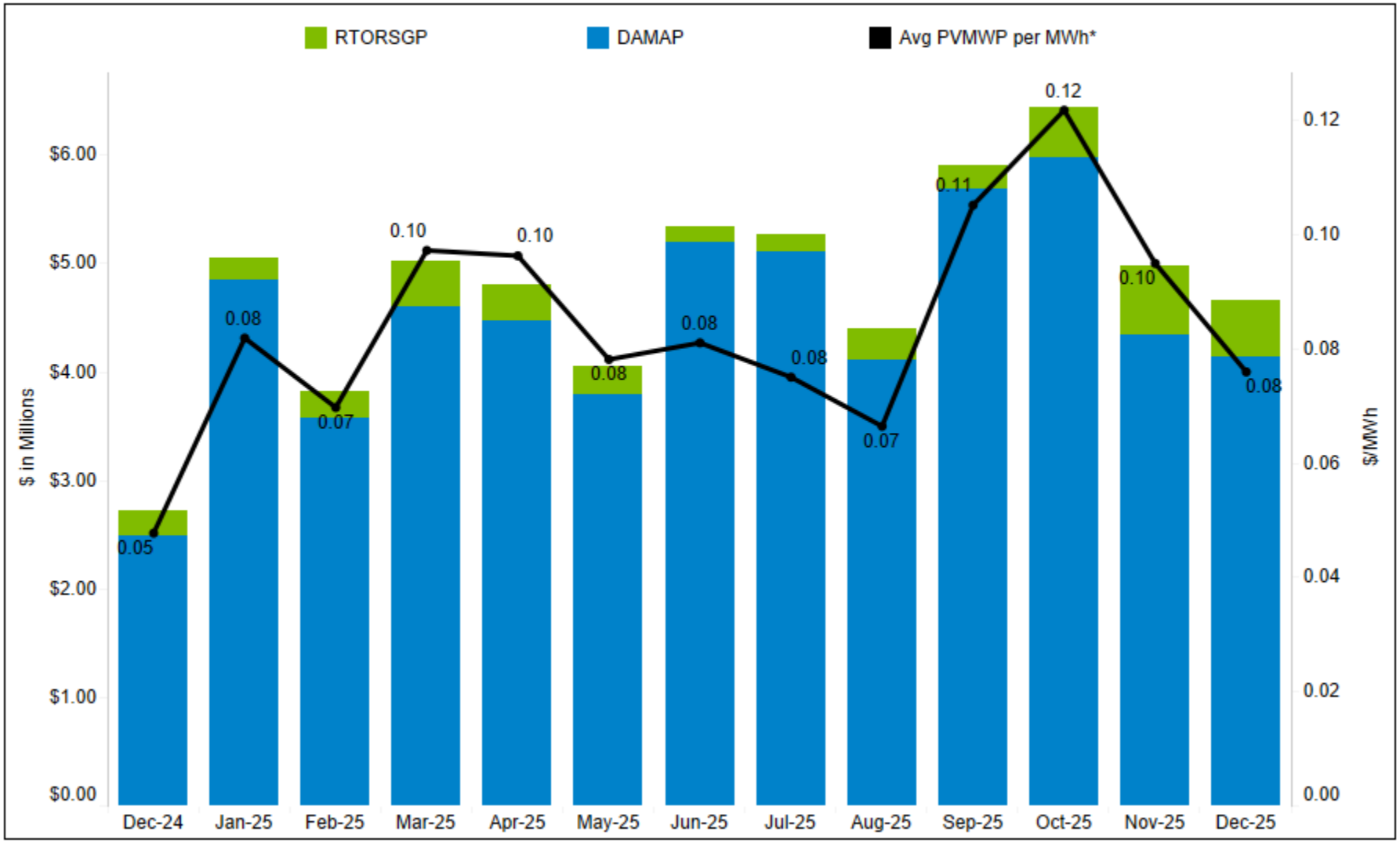
Day-Ahead and Real-Time Revenue Sufficiency Guarantee



	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
Chicago Gas Prices ($/MMBtu)	2.74	5.30	4.10	3.54	3.09	2.85	2.73	2.93	2.61	2.73	2.84	3.35	3.79
Henry Gas Prices ($/MMBtu)	3.03	5.40	4.13	4.10	3.43	3.12	3.01	3.25	2.90	2.95	3.12	3.73	4.24
^^RSG Per MWh to Energy Price (%)	0.27	0.32	0.26	0.33	0.25	0.31	0.30	0.23	0.19	0.29	0.43	0.36	0.42

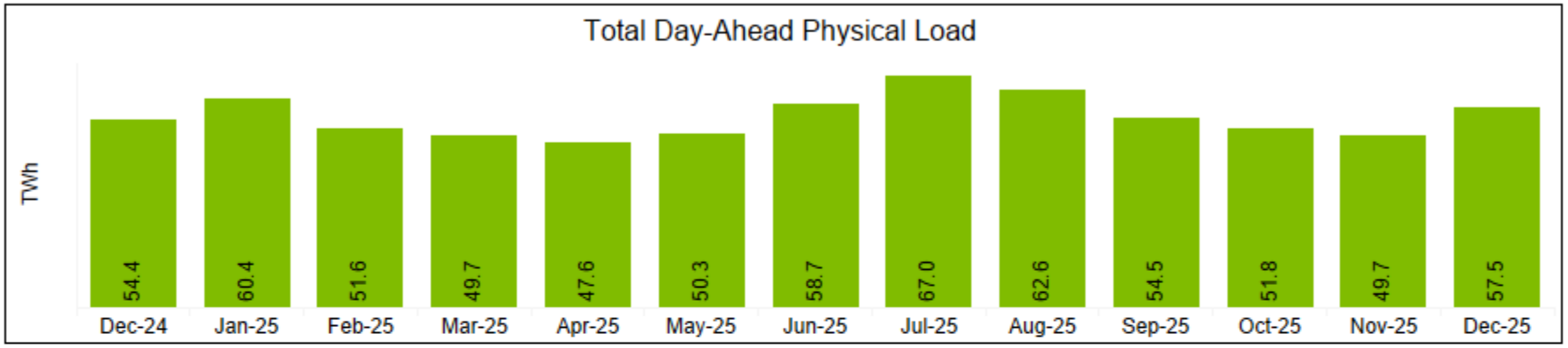
**Based on hourly ICCP Data; ^^metric value*
Values may change due to resettlement
Source: The Web-based Revenue Sufficiency Gurantee Report

Price Volatility Make Whole Payment



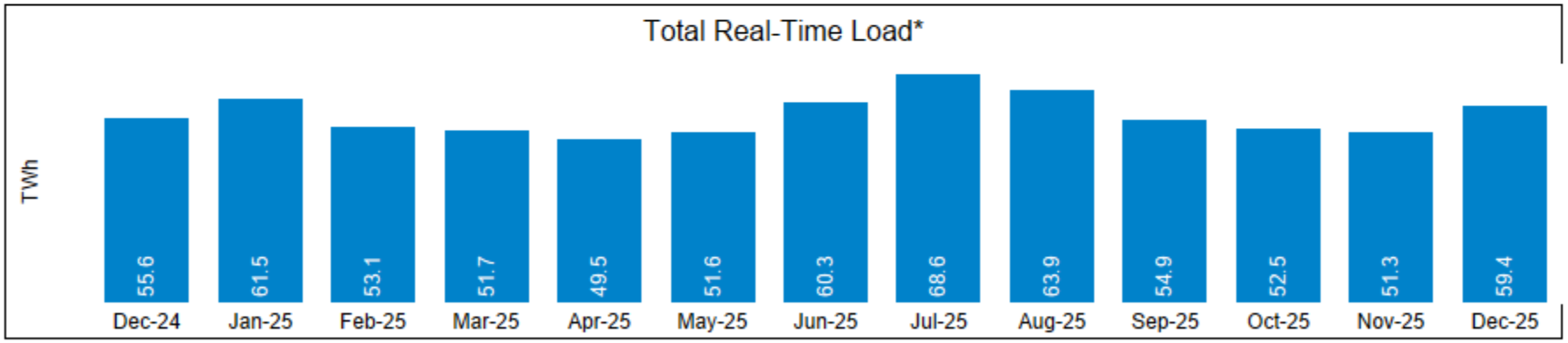
*Hourly ICCP data
Source: Web-based Revenue Neutrality Uplift Report

Day-Ahead and Real-Time Cleared Physical Energy



Day-Ahead Cleared Load Value (including Virtuals)

Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
$2.06B	$3.20B	$2.68B	$1.93B	$1.87B	$2.14B	$2.97B	$4.17B	$2.96B	$2.50B	$2.27B	$2.30B	$3.04B

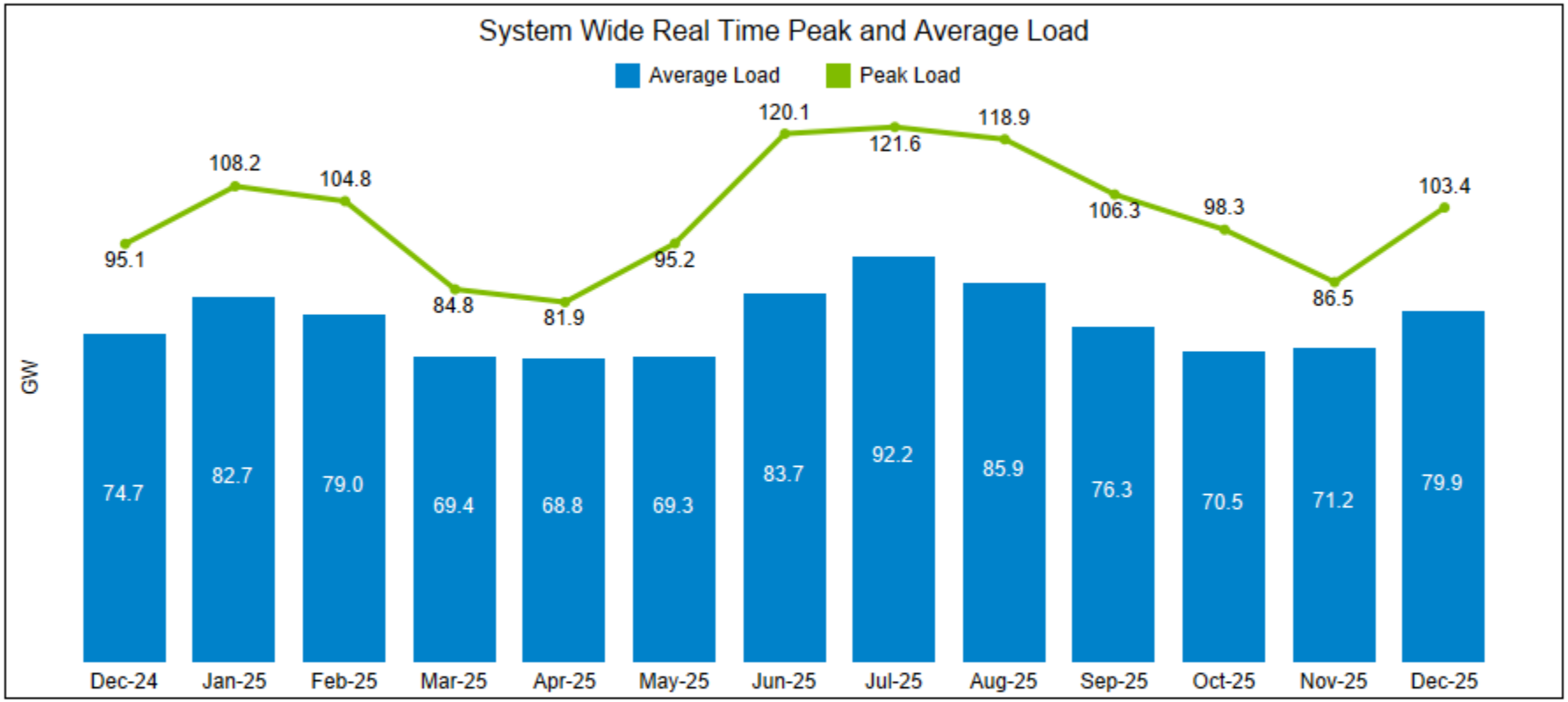


Real-Time Cleared Load Value ($ in Billions)

Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
$1.83B	$2.64B	$2.21B	$1.65B	$1.55B	$1.95B	$3.00B	$3.68B	$2.44B	$2.49B	$1.75B	$1.88B	$2.48B

**Sum of Hourly ICCP Load Data*
Source: MISO Market and Operations Analytics Department

Monthly System Load and Temperature



System Wide Load Weighted Temperature

	Dec-24	Nov-25	Dec-25
Average	30°F	45°F	25°F
Maximum	53°F	70°F	51°F
Minimum	3°F	24°F	-8°F

Load Weighted Heating & Cooling Degree Days

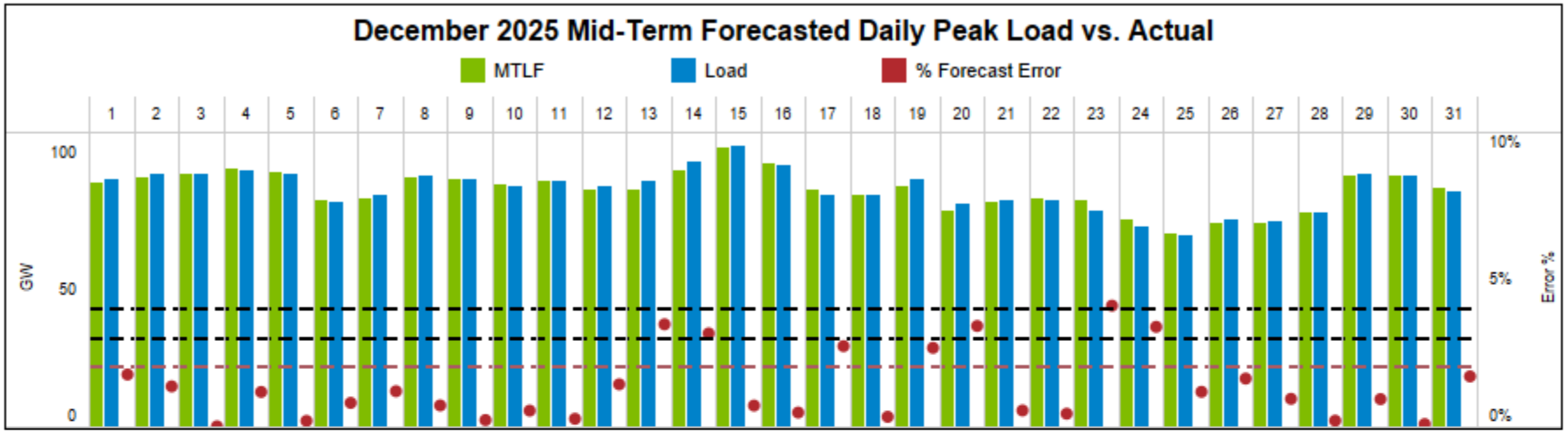
	Average HDD	Std Dev HDD	Average CDD	Std Dev CDD
Dec-25	37.16	12.31	0.00	0.00
Nov-25	16.91	9.17	0.10	0.70
Dec-24	31.55	11.22	0.00	0.00

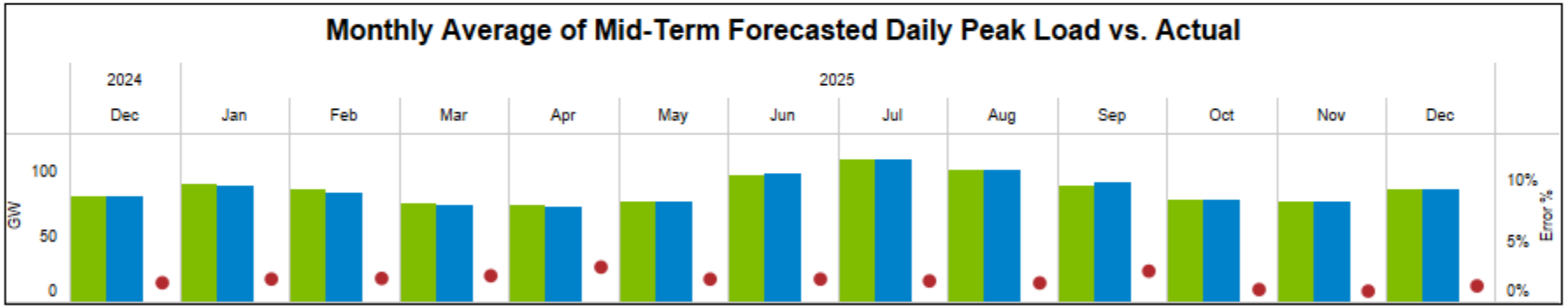
Hours with Load Greater than:

	100 GW	80 GW	60 GW
Dec-25	3	392	736
Nov-25	0	34	708
Dec-24	0	188	728

**Monthly data based on hourly ICCP Load Data; Hourly Integrated Peak Load Hour could differ from the Instantaneous Peak Load Hour.*
Source: MISO Market and Operations Analytics Department

Day-Ahead Mid-Term Load Forecast*



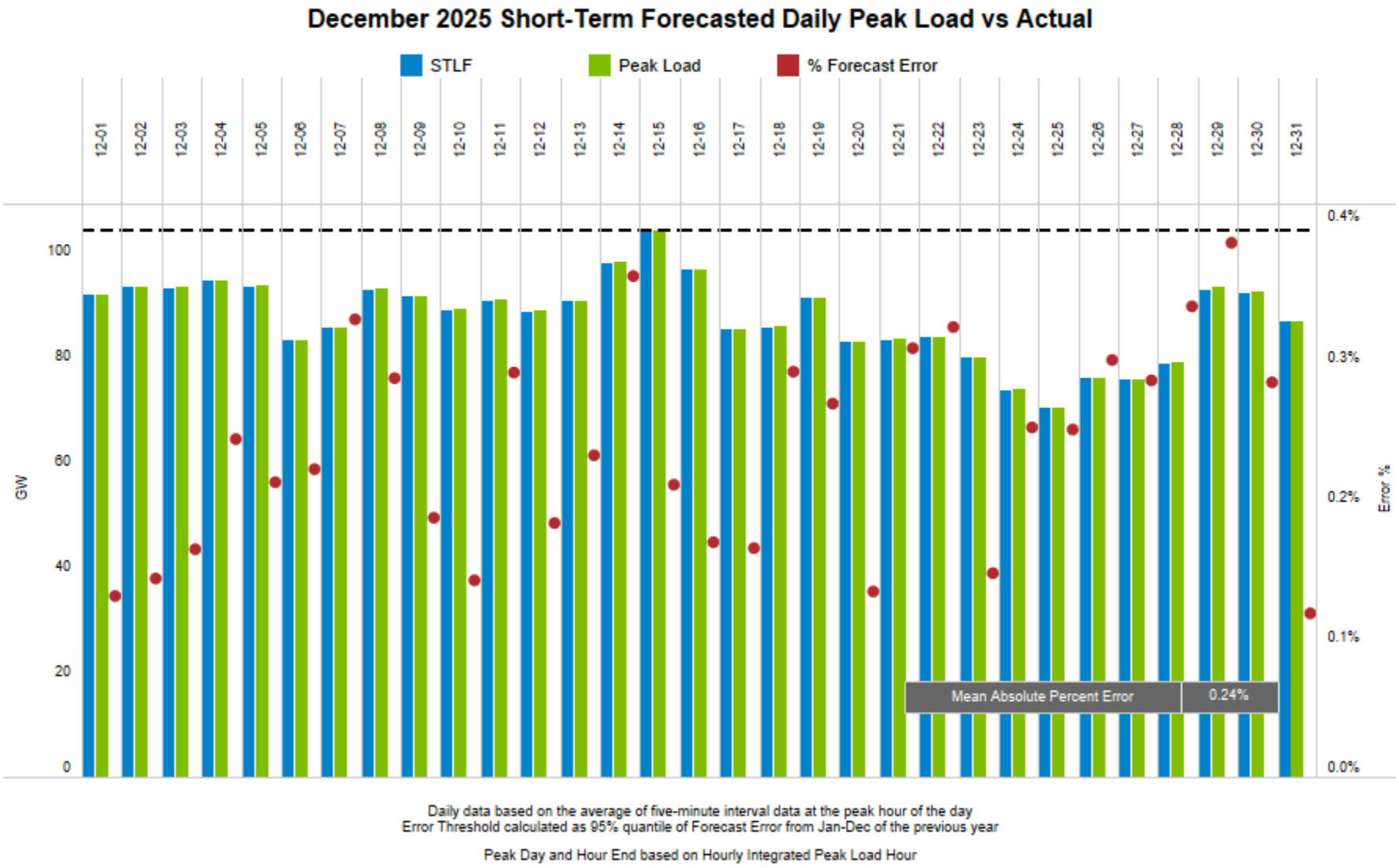


	2024	2025											
	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
% Std of Error (CV)	81.76	77.55	60.87	54.00	40.07	78.67	71.95	75.03	72.03	65.02	88.18	72.13	84.86
Mean of Error (MW)	1,334	1,742	1,674	1,671	2,191	1,474	1,852	1,950	1,670	2,382	841	731	1,167
Std of Error (MW)	1,090	1,351	1,019	902	878	1,159	1,332	1,463	1,203	1,549	742	527	990

* Monthly data based on the average of the daily integrated peak hours in the month
* Daily data based on the integrated peak hour of the day
* Peak Day and Hour End based on Hourly Integrated Peak Load Hour

Source: MISO Operations Risk Management

Short-Term Load Forecast*

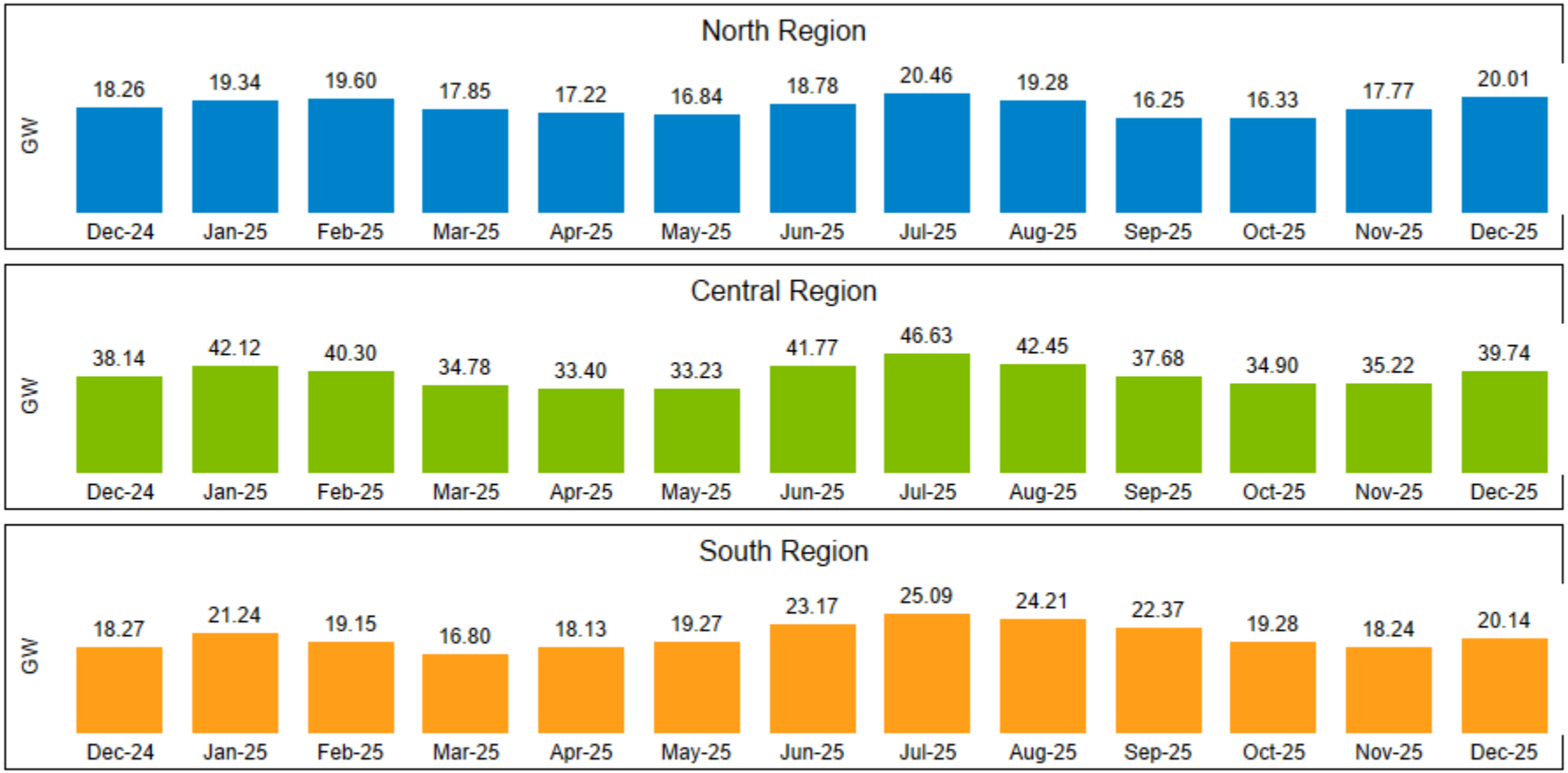


Daily data based on the average of five-minute interval data at the peak hour of the day
Error Threshold calculated as 95% quantile of Forecast Error from Jan-Dec of the previous year

Peak Day and Hour End based on Hourly Integrated Peak Load Hour

Source: MISO Operations Risk Management

Average Load by Region

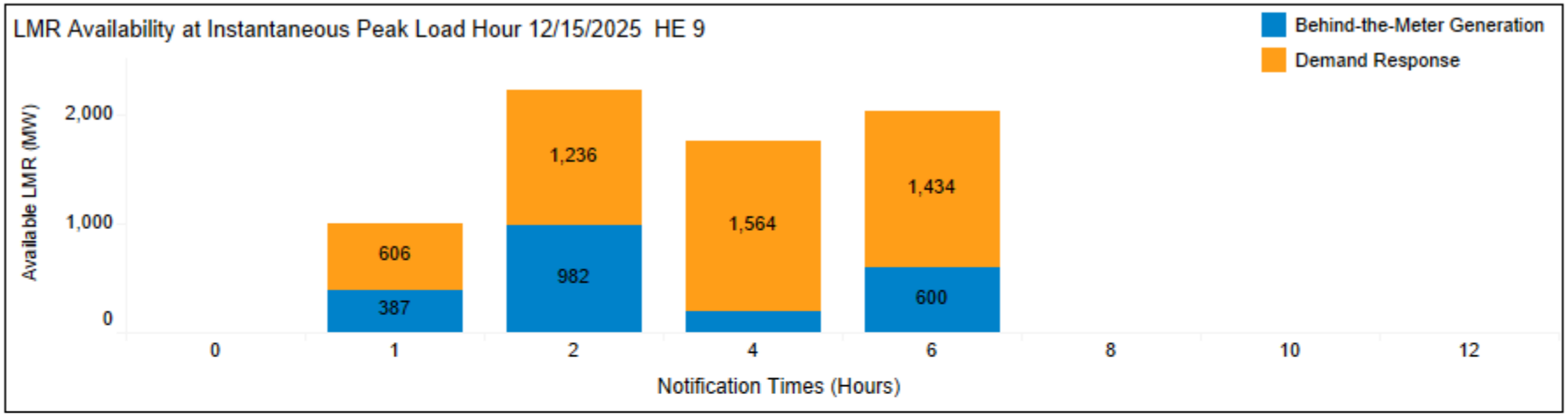


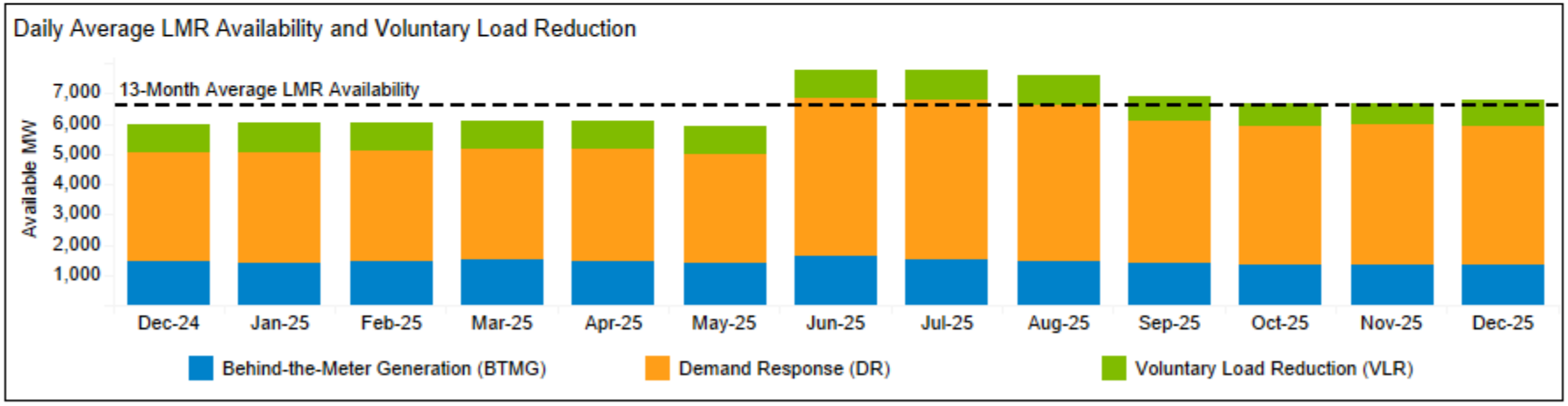
Hourly Integrated System Load Peak Hour Ending: 12/15/2025 09 EST

North	23.09 GW
Central	50.83 GW
South	29.30 GW
MISO	102.28 GW

**Monthly data based on hourly ICCP Load Data; Hourly Integrated Peak Load Hour could differ from the Instantaneous Peak Load Hour.*
Source: MISO Market and Operations Analytics Department

Market Participant entered Load Modifying Resource (LMR) Availabililty

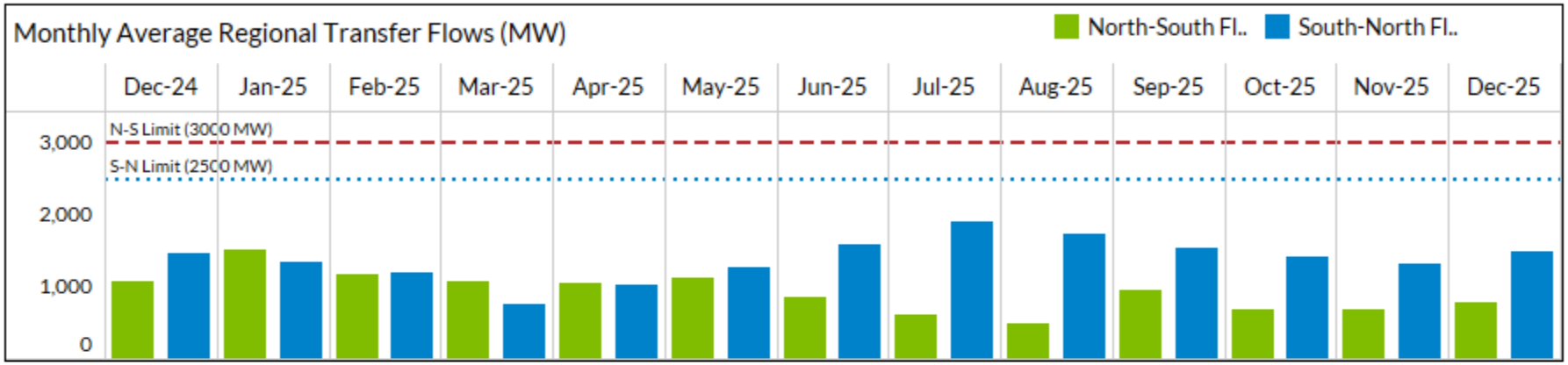




PRA Auction	BTMG (MW)	DR (MW)	Total BTMG and DR (MW)
Summer 2024	4,144	8,109	12,253
Summer 2025	4,283	9,004	13,287

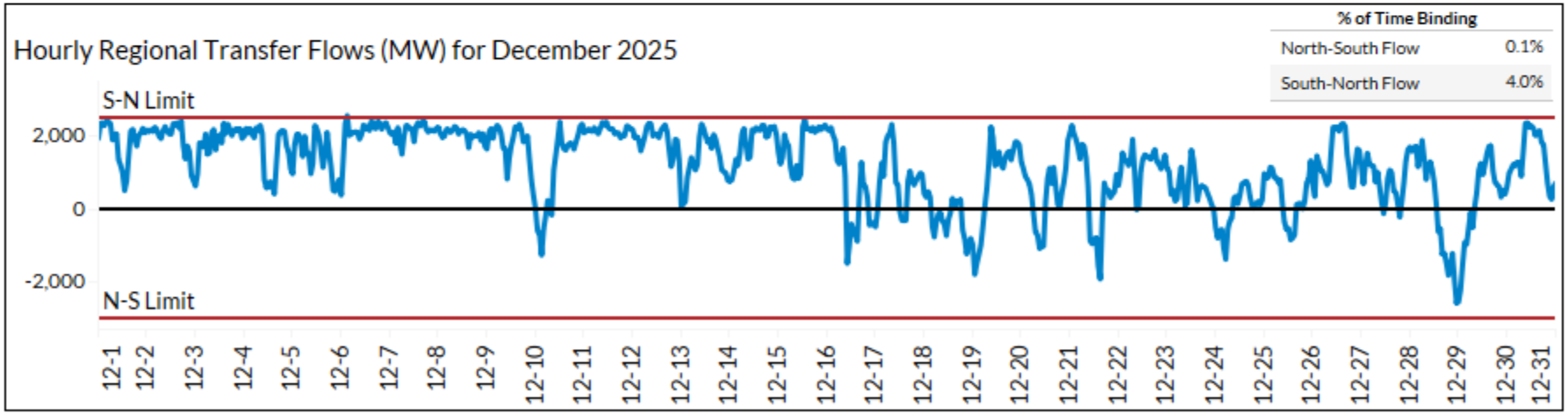
Source: MISO Markets and Operations Analytics Department

Regional Directional Transfer**



Percentage of Time Regional Directional Flow

	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
North-South Flow	22%	29%	40%	61%	44%	49%	26%	3%	4%	12%	19%	15%	13%
South-North Flow	78%	71%	60%	39%	56%	51%	74%	97%	96%	88%	81%	85%	87%

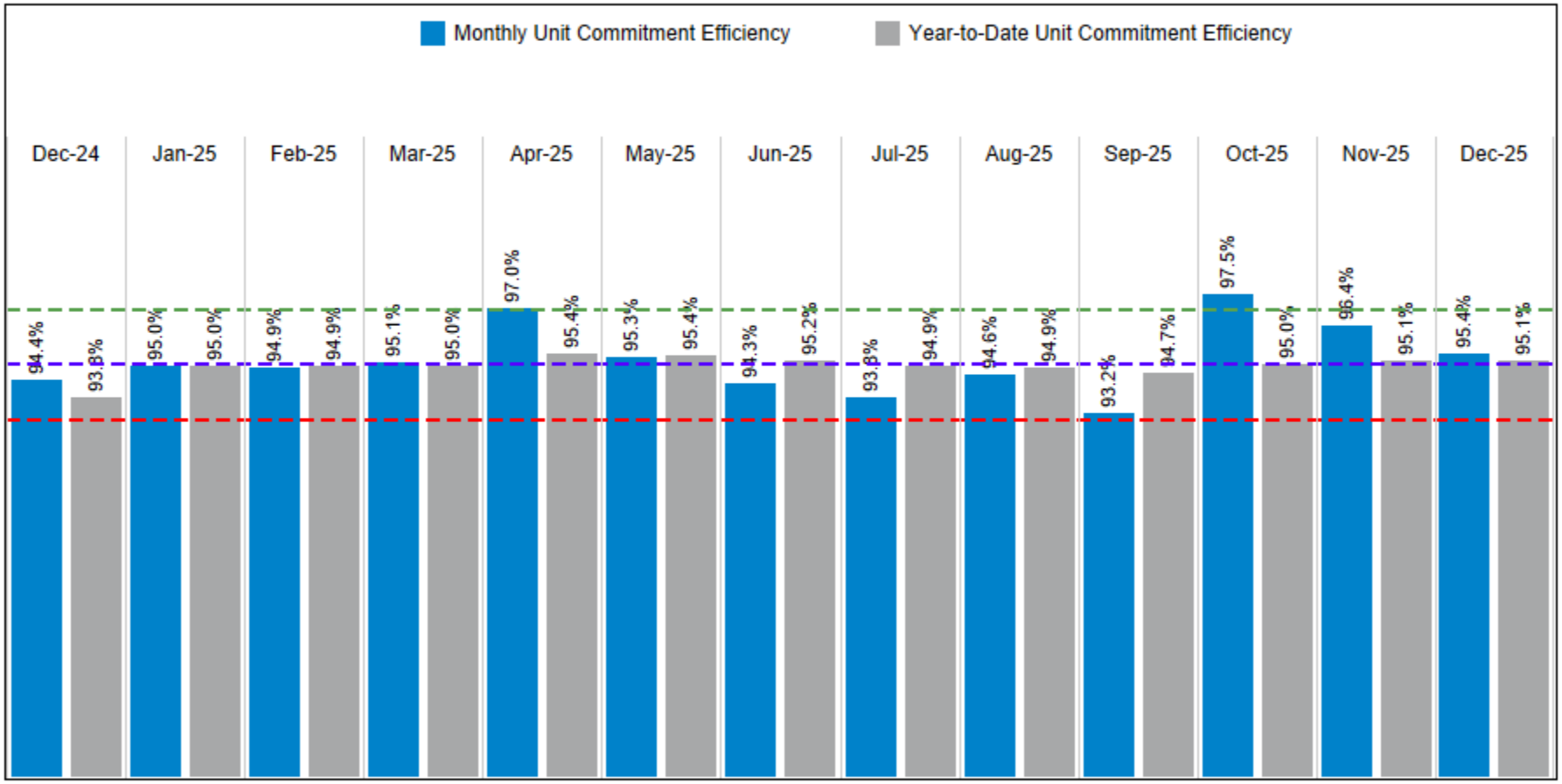


***Regional Directional Transfer between MISO South and Central/North Regions*
Source: MISO Markets and Operations Analytics Department

Unit Commitment Efficiency

Effectively commit generation to meet demand obligations and mitigate constraints

H

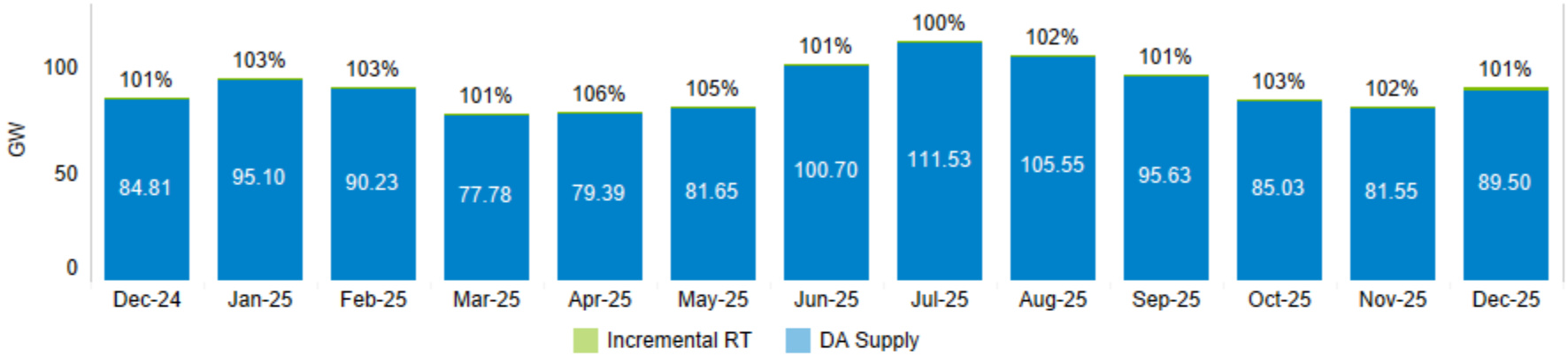


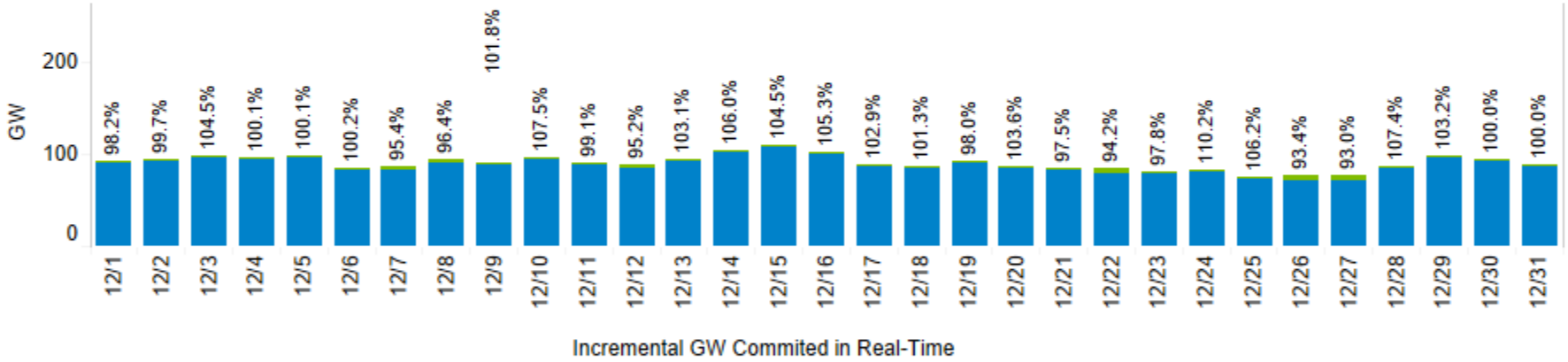
	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
Actual Cost	$988M	$1,311M	$1,069M	$819M	$756M	$829M	$1,095M	$1,427M	$1,168M	$1,041M	$899M	$929M	$1,173M
Optimal Cost	$978M	$1,300M	$1,061M	$812M	$752M	$822M	$1,085M	$1,415M	$1,159M	$1,029M	$894M	$923M	$1,163M
Sunk Cost	$807M	$1,095M	$897M	$673M	$628M	$678M	$913M	$1,229M	$1,004M	$864M	$732M	$758M	$952M

Source: MISO Optimal Dispatch Calculator (ODC)

Unit Commitment Efficiency = 1-((Actual cost – Optimal cost)/(Actual cost – Sunk cost))

Day-Ahead Supply and Real-Time Load Obligation at the Peak Load Hour





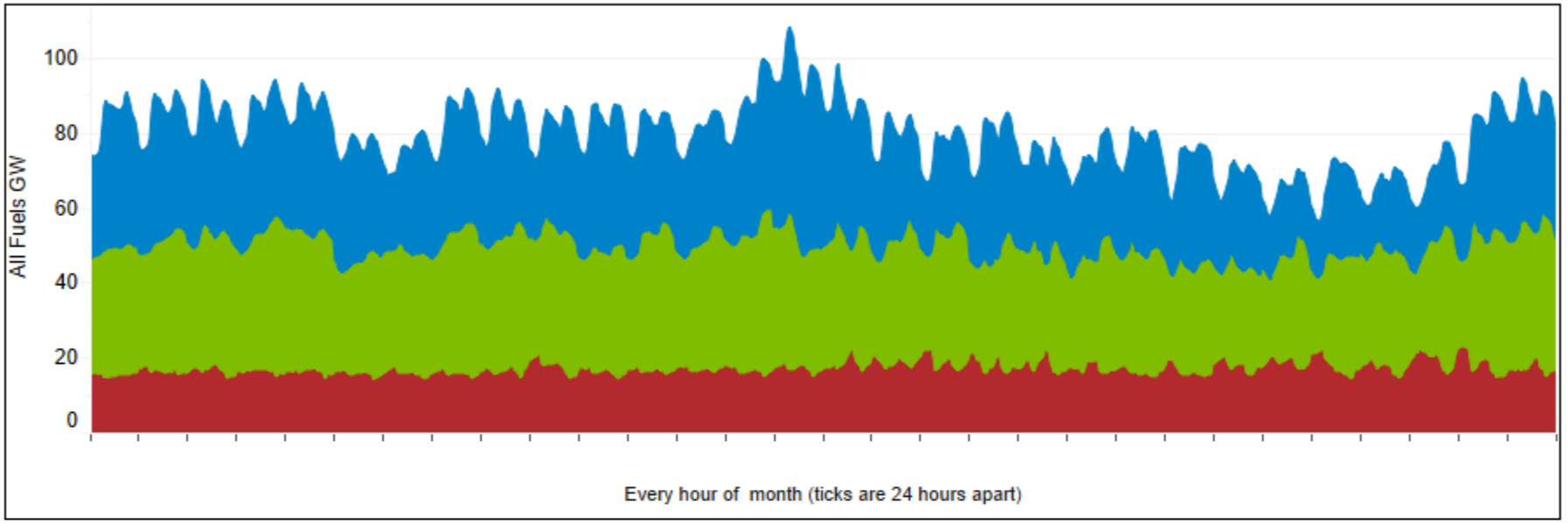
Incremental GW Commited in Real-Time

12/1	12/2	12/3	12/4	12/5	12/6	12/7	12/8	12/9	12/10	12/11	12/12	12/13	12/14	12/15	12/16	12/17	12/18	12/19	12/20	12/21	12/22	12/23	12/24	12/25	12/26	12/27	12/28	12/29	12/30	12/31
1.69	0.31	-4.23	-0.09	-0.07	-0.16	4.02	3.38	-3.27	-6.77	0.85	4.34	-2.85	-5.94	-4.77	-5.17	-2.53	-1.10	1.89	-3.05	2.16	4.95	1.78	-7.63	-4.44	5.09	5.42	-5.95	-3.04	-0.05	-0.01

Day-Ahead Supply is the Day-Ahead Economic Maximum received in Real-Time plus Behind-the-Meter plus Day-Ahead NSI at the Peak Hour
Real-Time Obligation is the Real-Time ICCP Load plus Real-Time Regulation Requirement plus Real-Time Spinning Requirement at the Peak Hour
Real-Time Increment is the Real-Time Obligation less Day-Ahead Supply at the Peak Hour
Percents calculated as Day-Ahead Supply divided by Real-Time Obligation

Source: MISO Market and Operations Analytics Department

Self Committed and Economically Dispatched Energy - December 2025

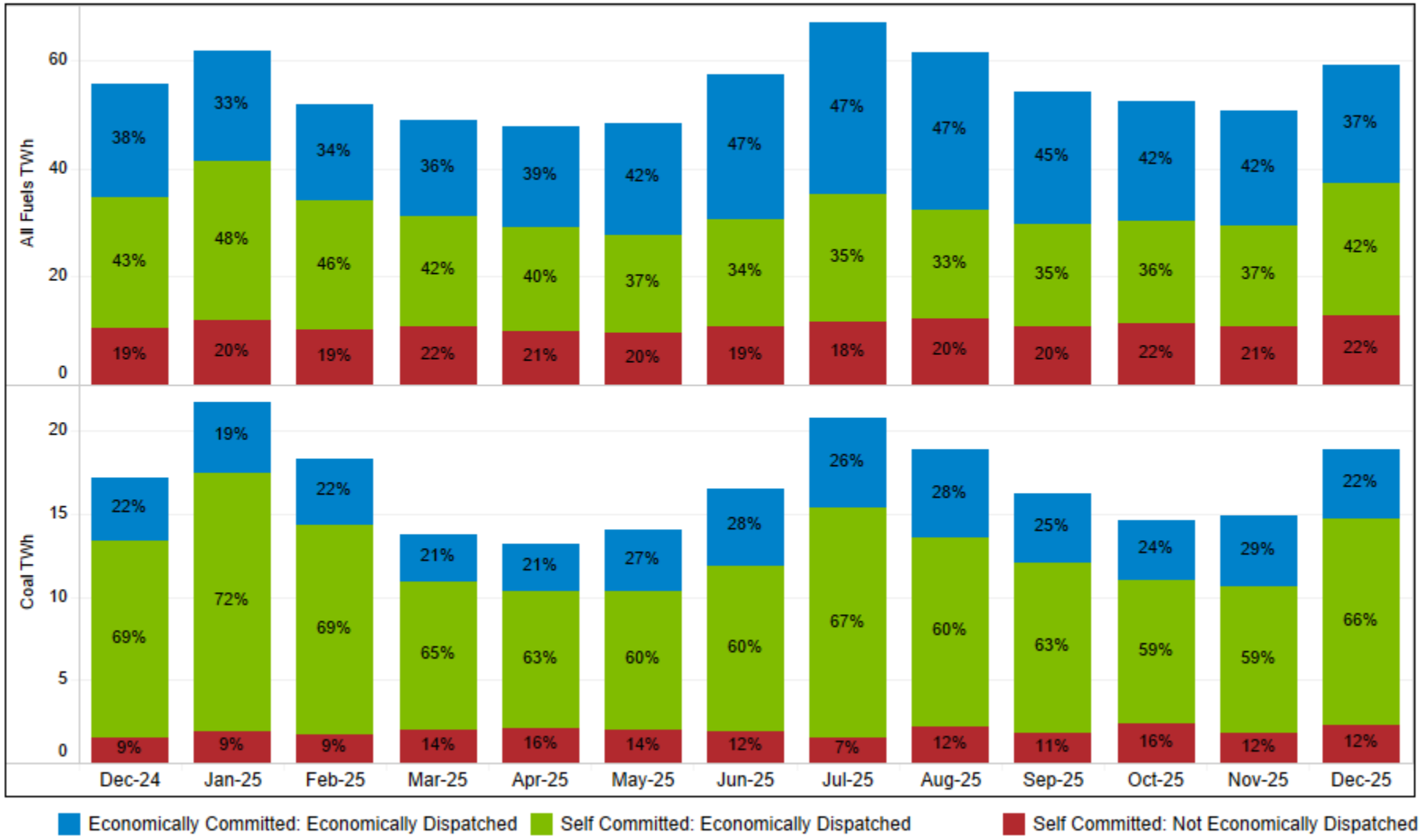


	All Fuels		Coal		Gas	
	TWh	%	TWh	%	TWh	%
Economically Committed: Economically Dispatched	21.9	37%	4.2	22%	13.1	66%
Self Committed: Economically Dispatched	24.5	42%	12.5	66%	5.4	27%
Self Committed: Not Economically Dispatched	12.7	22%	2.2	12%	1.3	6%
Grand Total	**59.1**	**100%**	**18.9**	**100%**	**19.8**	**100%**

Economically Committed: Economically Dispatched	Generation committed by MISO and dispatched on economic offers.
Self Committed: Economically Dispatched	Generation that is self-committed, but Resource Owners allow MISO to dispatch economically after the self-schedule portion of their resource offer is satisfied. Self-commitments can be used to manage local reliability, operational constraints, and fuel contract constraints.
Self Committed: Not Economically Dispatched	Energy from self-committed generation produced at its minimum level or is block-loaded and cannot be dispatched. Block Loaded energy is not necessarily uneconomic, but MISO has no ability to dispatch it based on economics.

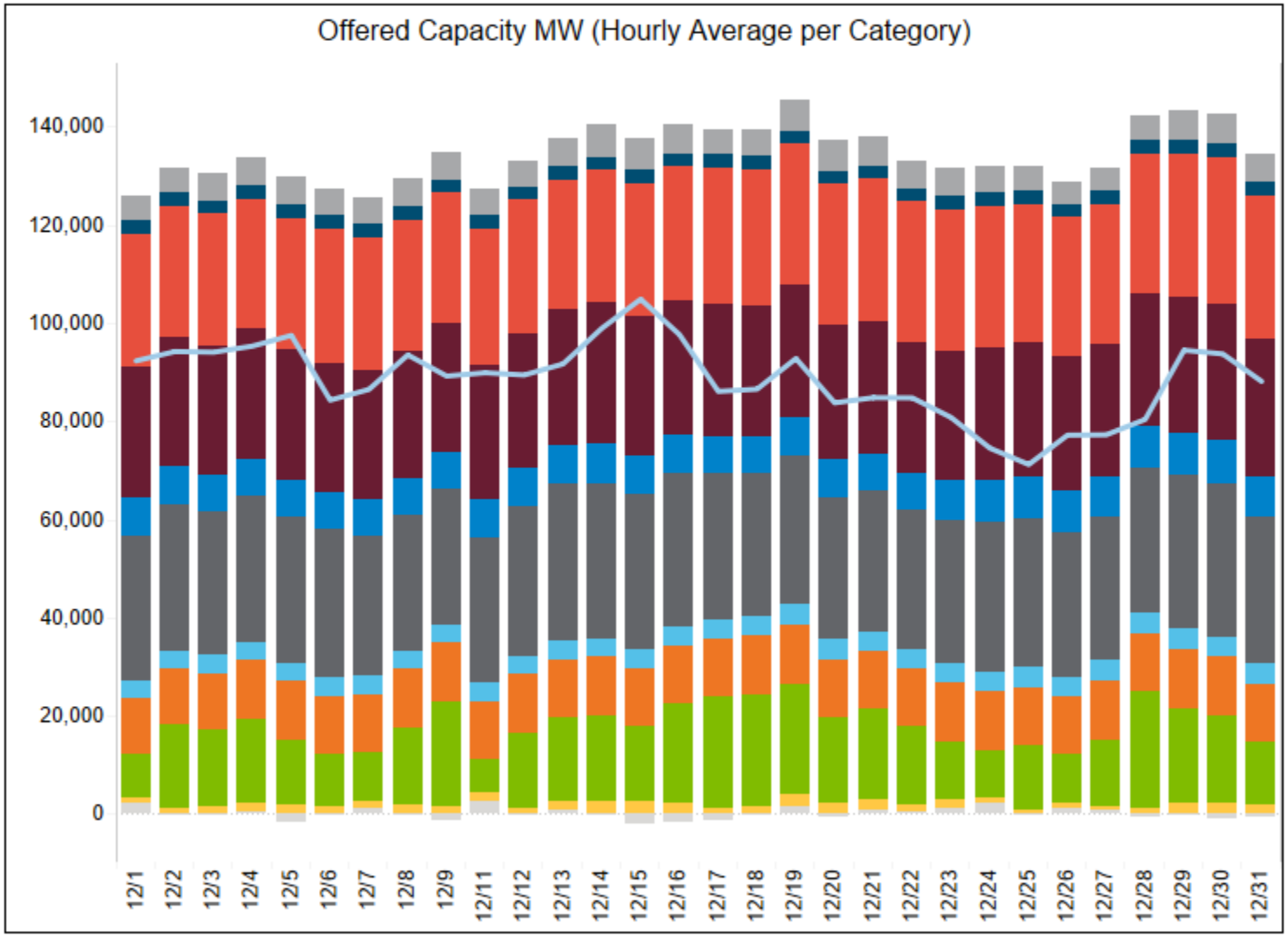
Source: MISO Market and Operations Analytics Department

Monthly Trend - Self Committed and Economically Dispatched Energy



Source: MISO Market and Operations Analytics Department

Offered Capacity and Real-Time Peak Load Obligation



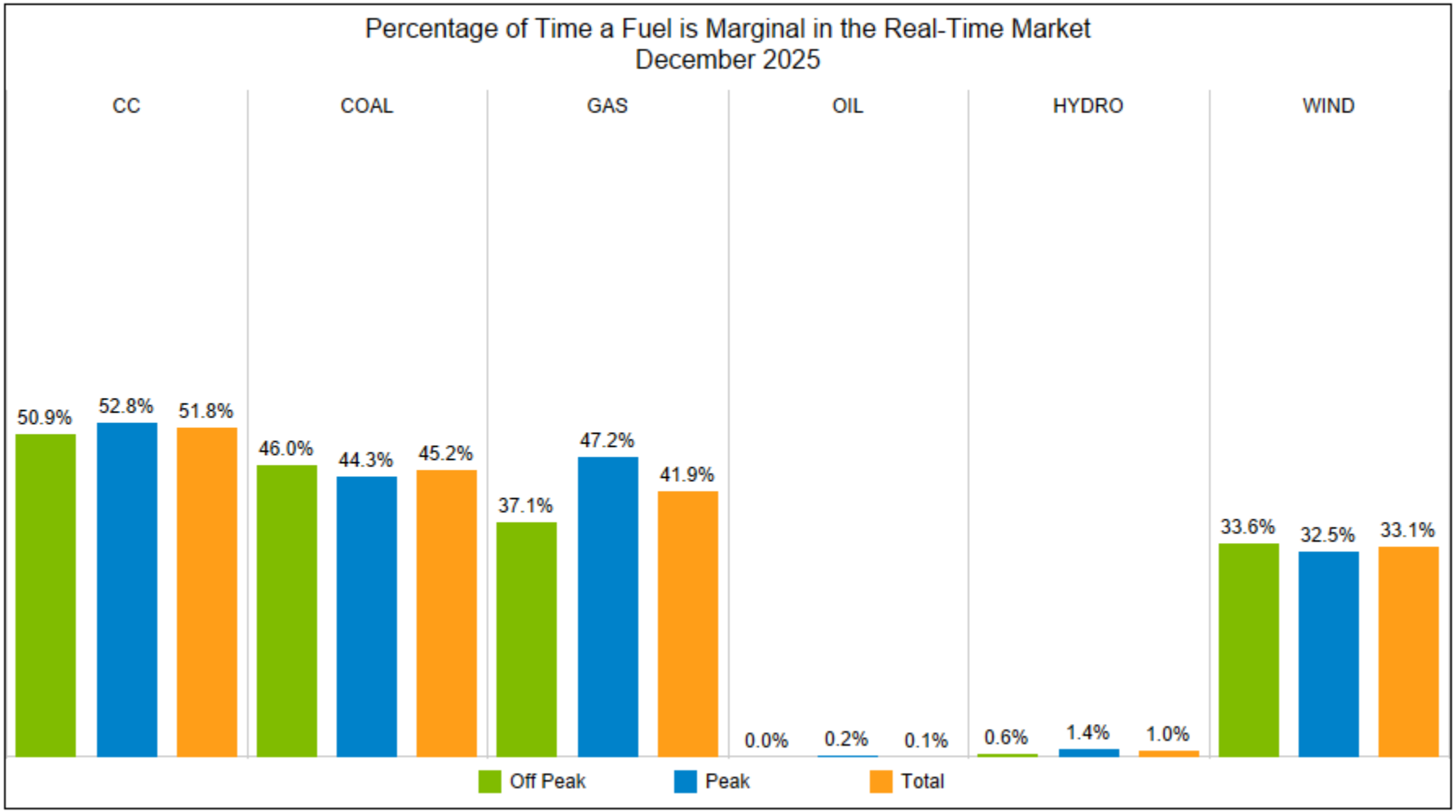
* Real-Time ICCP Load plus Real-Time Regulation Requirement plus Real-Time Spinning Requirement at the daily Peak hour.

** Other includes DRR, SER, pet coke, and waste units.

*** Gas excludes CC and CT.

Source: MISO Market and Operations Analytics Department

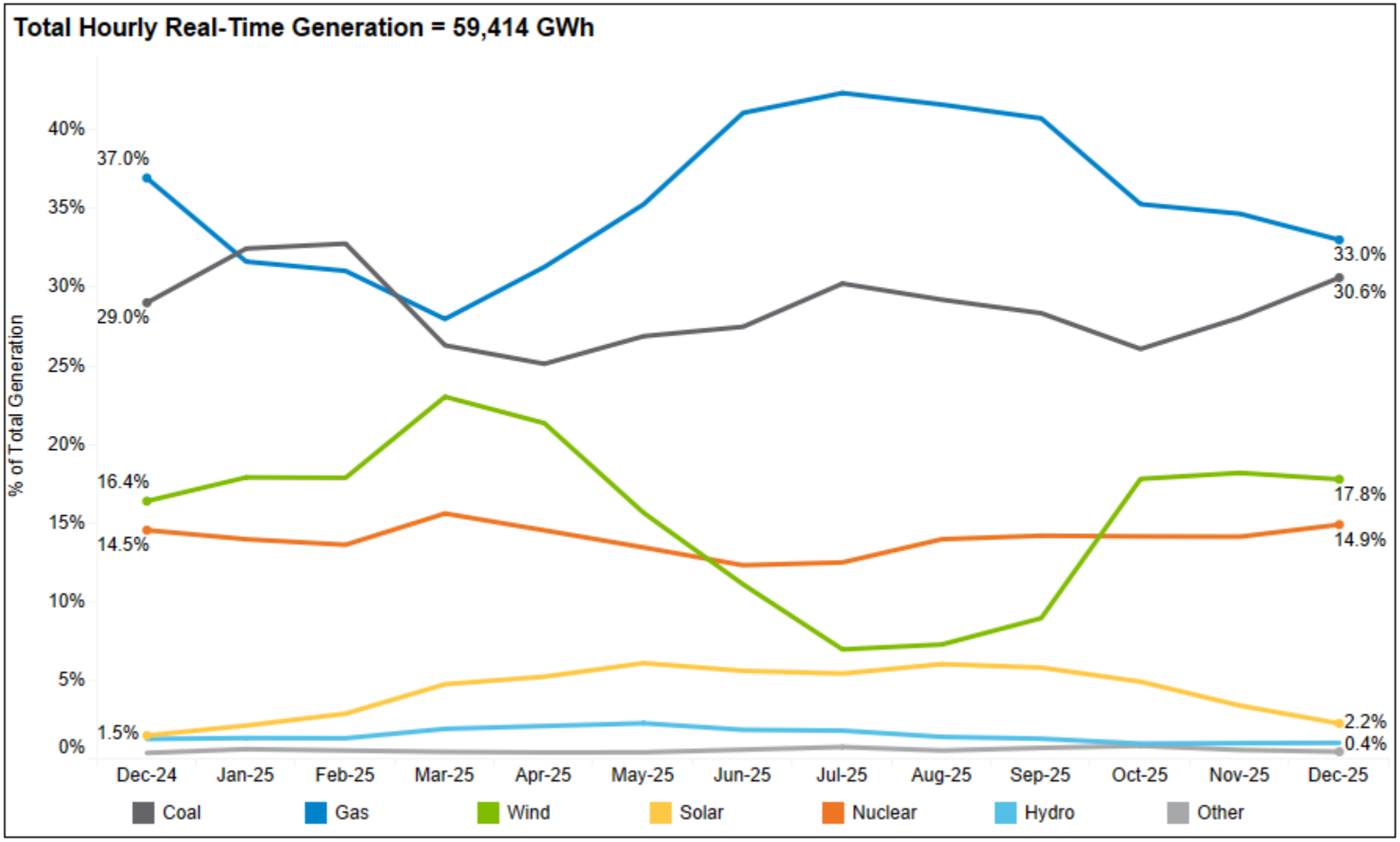
Marginal Fuel



Note: Binding transmission constraints can produce instances where more than one unit is marginal in the system. Consequently, more than one fuel may be on the margin; and since each marginal unit is included in the analysis, the percentage may sum to more than 100%.

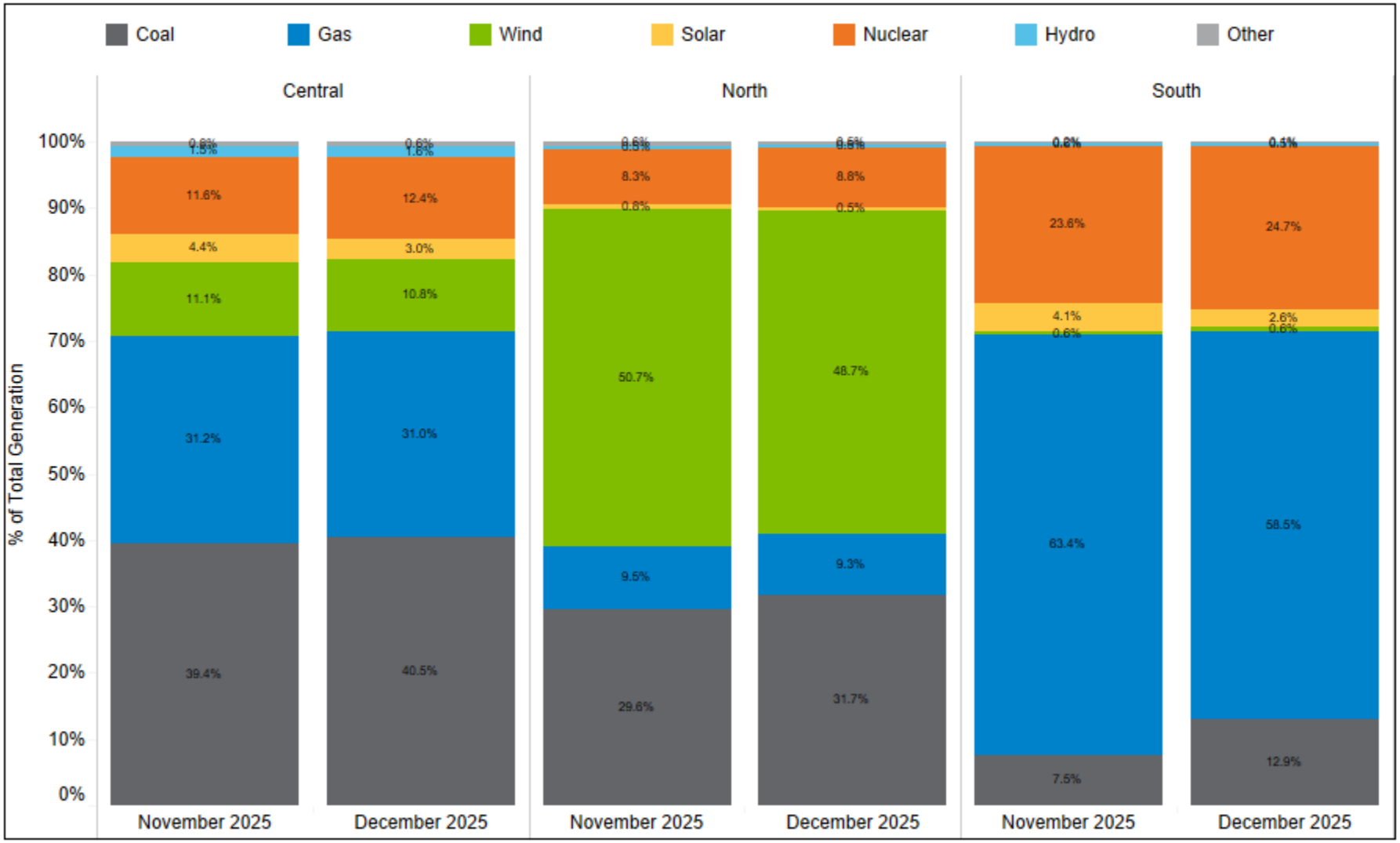
Source: MISO Market and Operations Analytics Department

Real-Time Generation Fuel Mix



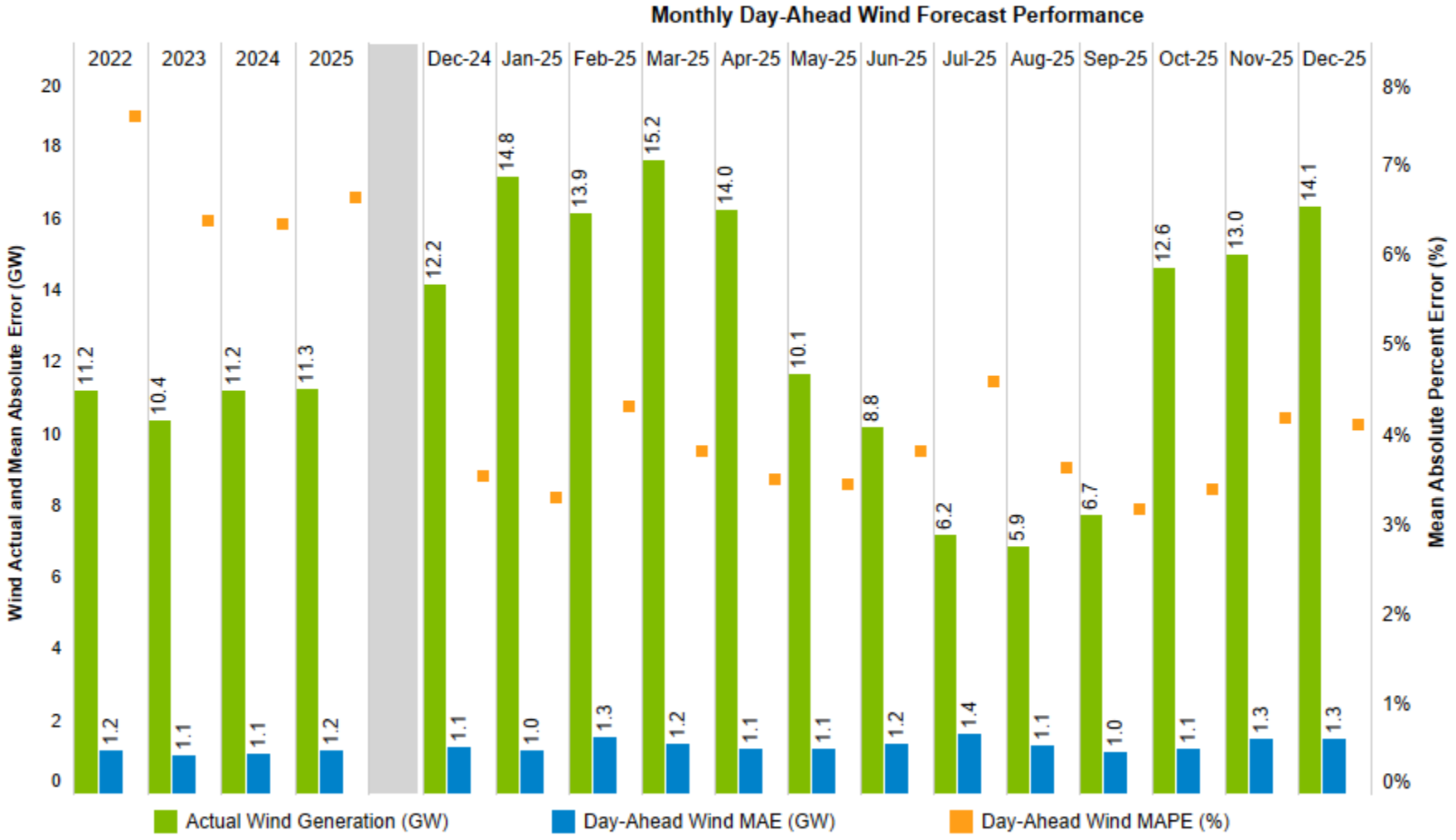
Based on hourly unit level state estimator data
Other includes: Battery, Oil, Pet Coke, Waste and Other fuels
Source: MISO Market and Operations Analytics Department

Real-Time Generation Fuel Mix by Region



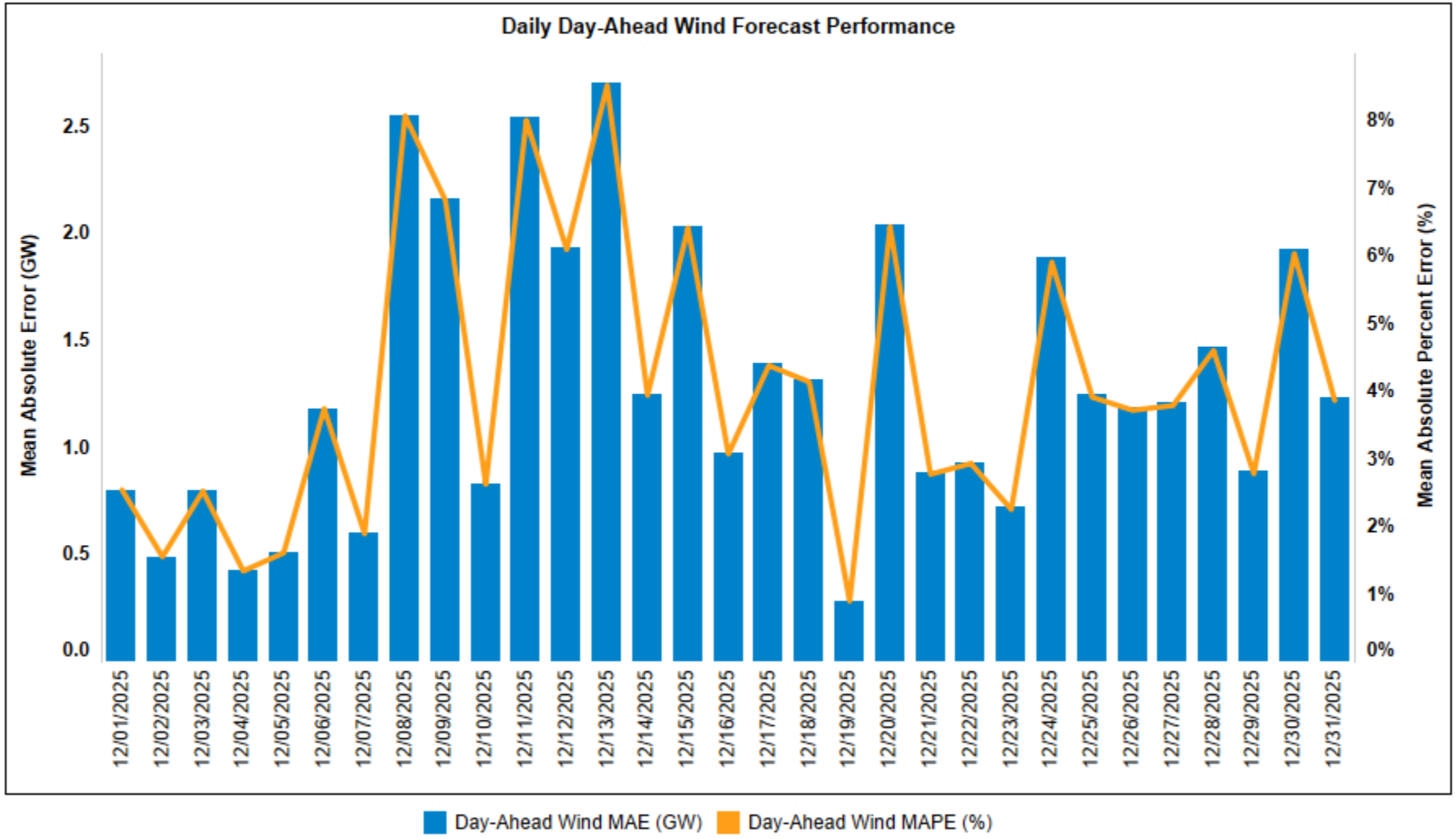
Based on hourly unit level state estimator data
Other includes: Battery, Oil, Pet Coke, Waste and Other fuels
Source: MISO Market and Operations Analytics Department

Monthly Day-Ahead Wind Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)



Source: MISO Operations Risk Management

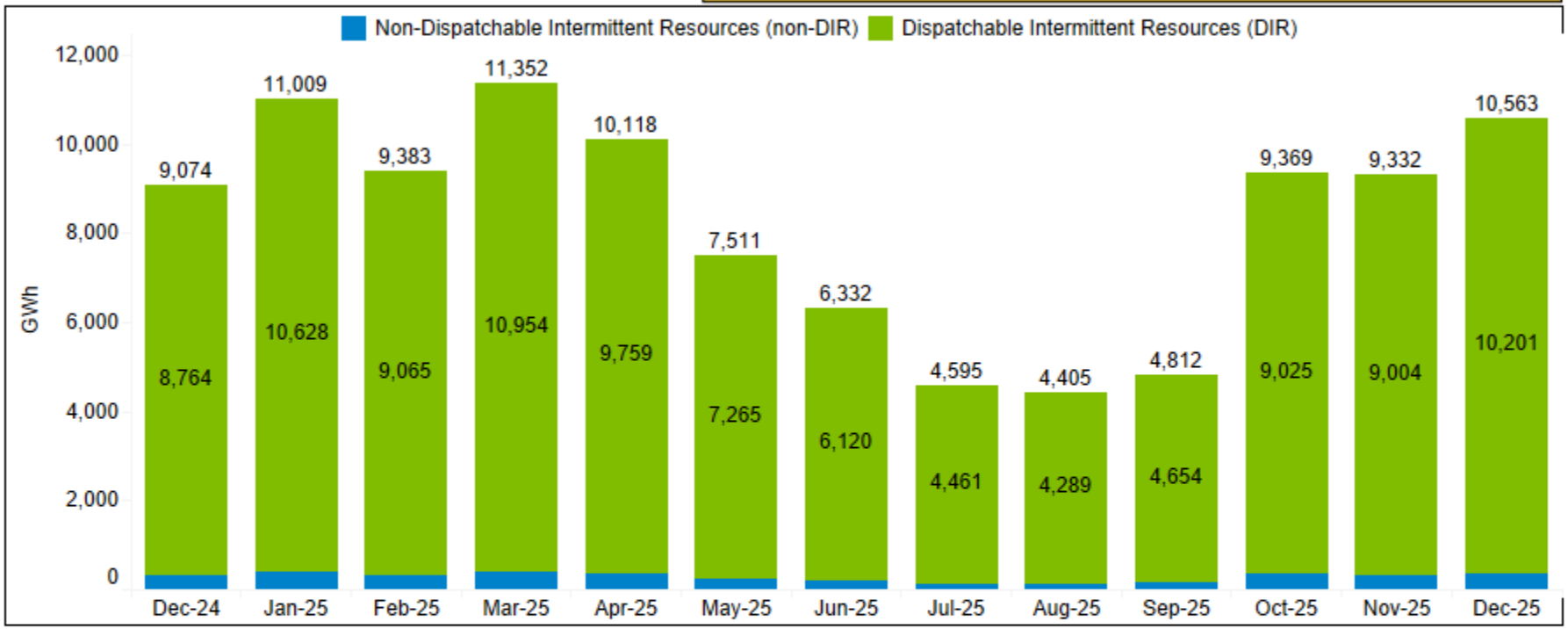
Daily Day-Ahead Wind Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)



Source: MISO Operations Risk Management

Monthly Wind Energy Generation

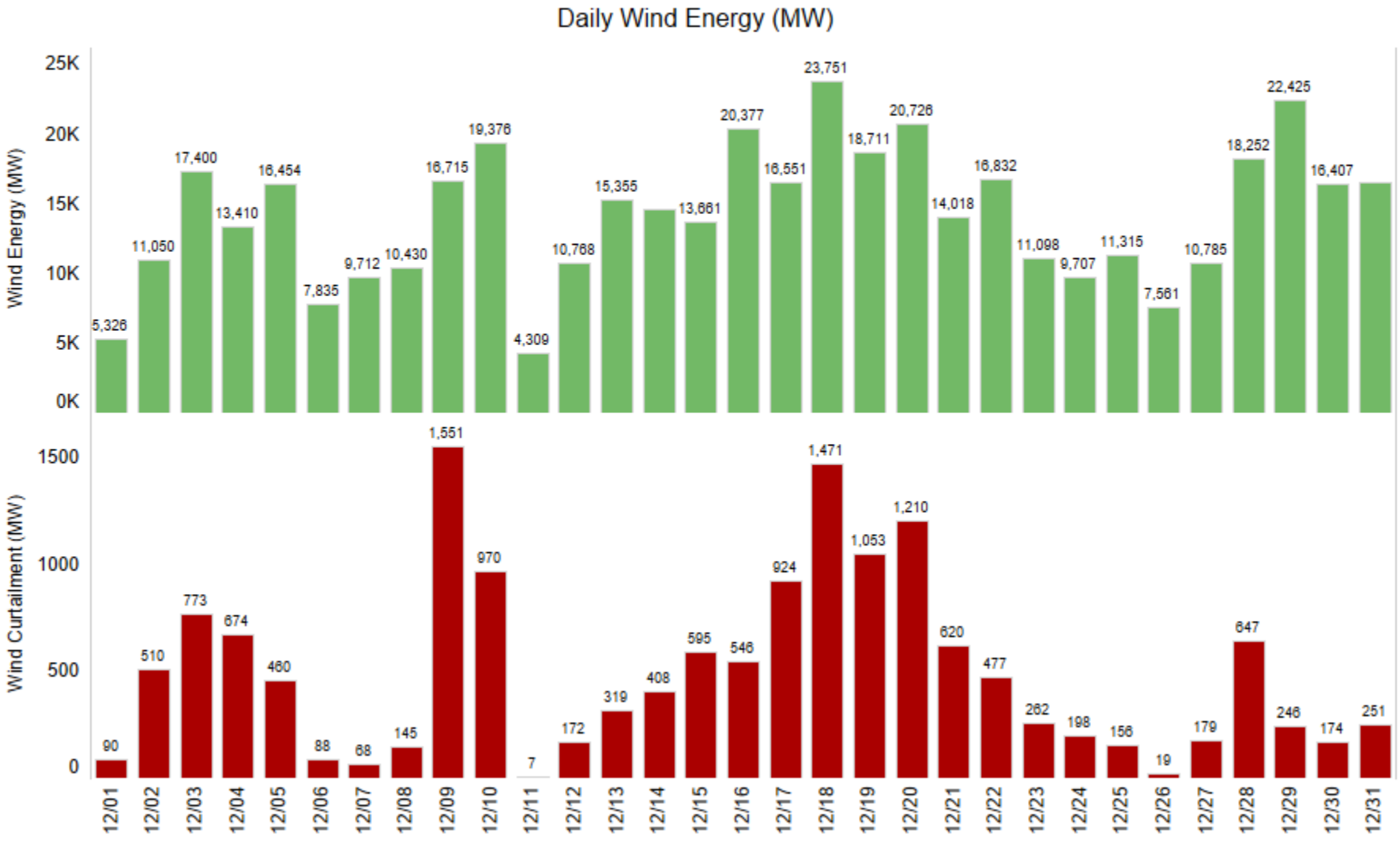
As of 09/05/2025
Registered Wind Capacity = 32,464 MW; Inservice Wind Capacity = 31,450 MW
Registered DIR Capacity = 30,936 MW; Inservice DIR Capacity = 29,922 MW



	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
Peak Wind Date and Hour Ending	12/4 11	1/28 21	2/28 22	3/23 15	4/28 19	5/16 21	6/21 15	7/5 1	8/8 7	9/5 6	10/21 13	11/26 13	12/28 24
Peak hourly wind output (MW)	24,044	25,218	24,646	24,172	23,582	22,803	21,086	15,404	15,824	20,284	22,614	23,562	25,841
Peak wind output as % of MISO load in that hour	28.7%	31.2%	34.1%	34.6%	28.6%	28.6%	19.3%	19.2%	19.4%	29.9%	29.8%	29.7%	35.8%
Wind Energy as a percent of MISO Energy	16.3%	18.2%	18.1%	23.2%	21.5%	15.6%	11.3%	7.3%	7.5%	9.2%	18.1%	18.2%	17.8%
DIR dispatch below Max as % of avail. DIR	2.3%	3.3%	2.0%	3.1%	4.3%	3.3%	3.3%	1.3%	2.6%	2.9%	2.9%	3.0%	2.7%

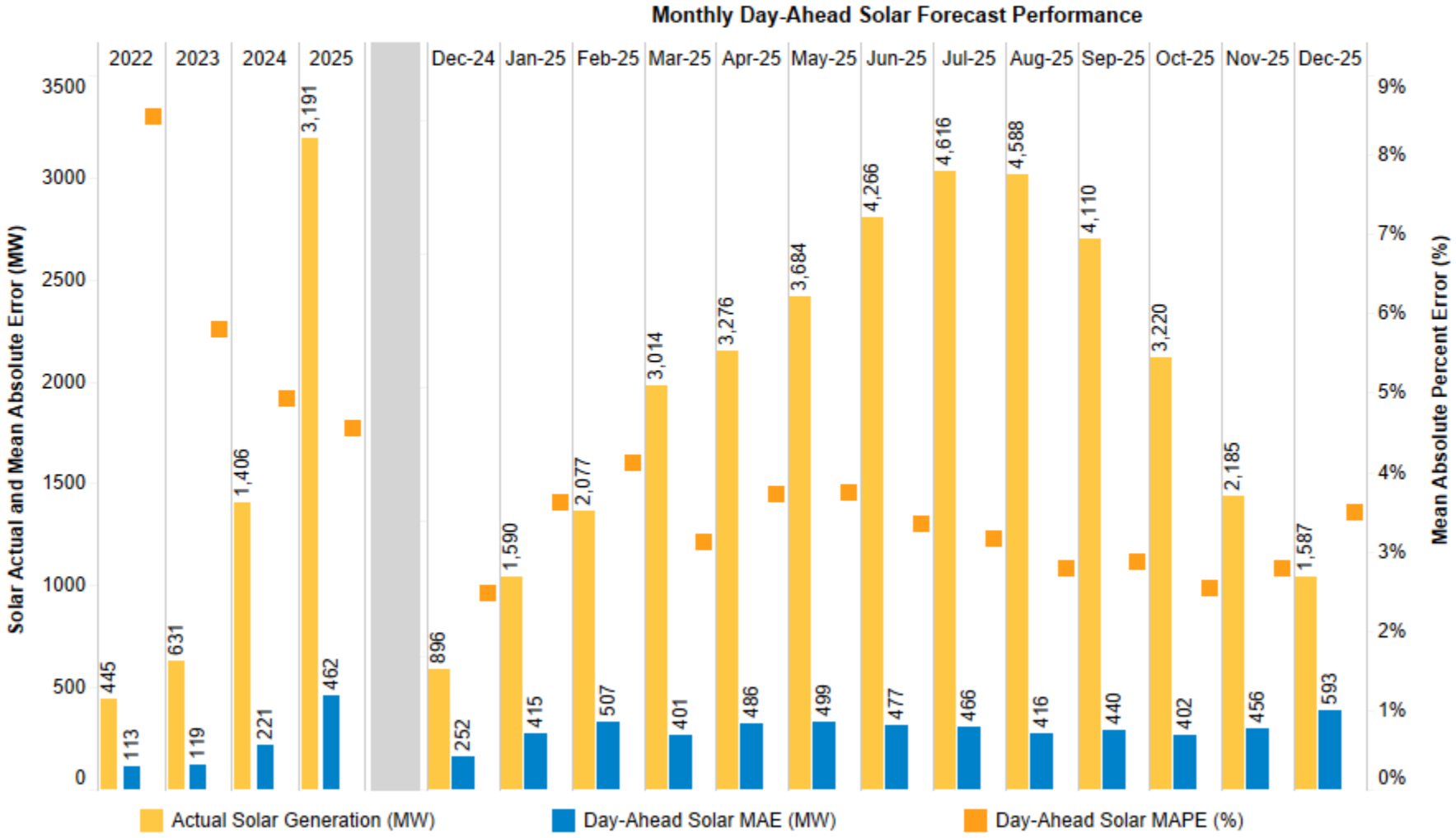
**Hourly State Estimator data*
Source: MISO Market and Operations Analytics Department

Daily Average Wind Energy and Curtailment



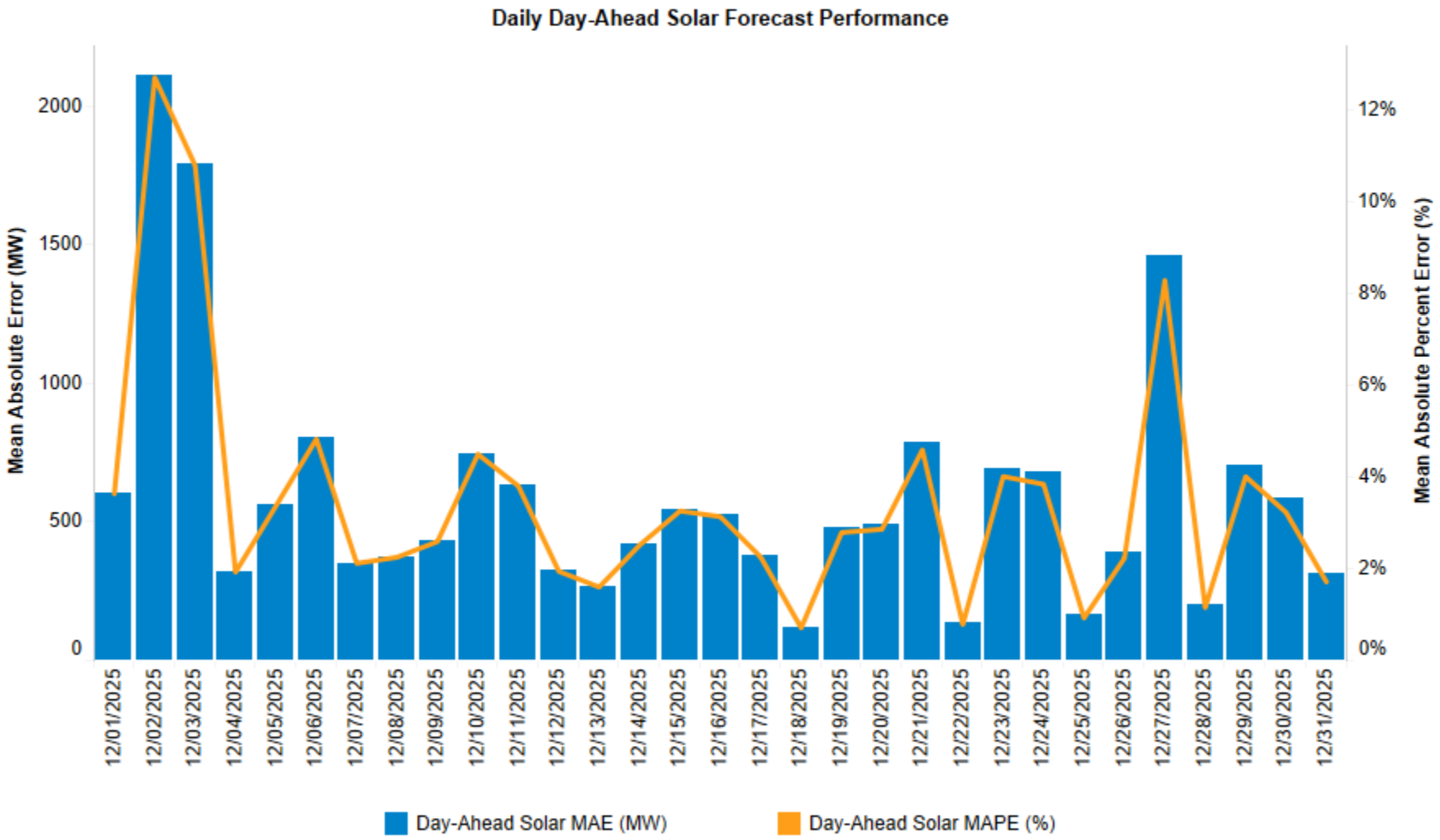
Source: MISO Market and Operations Analytics Department

Monthly Day-Ahead Solar Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)



Source: MISO Operations Risk Management

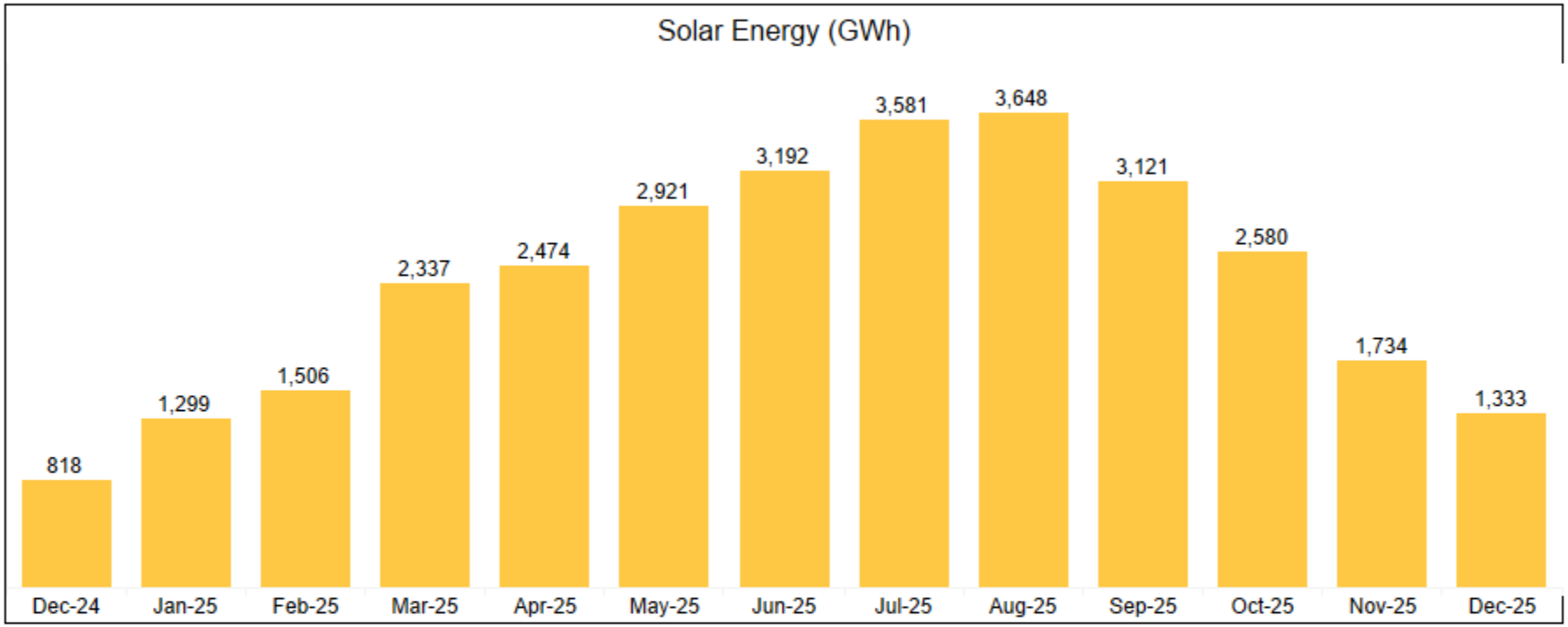
Daily Day-Ahead Solar Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)



Source: MISO Operations Risk Management

Monthly Solar Energy

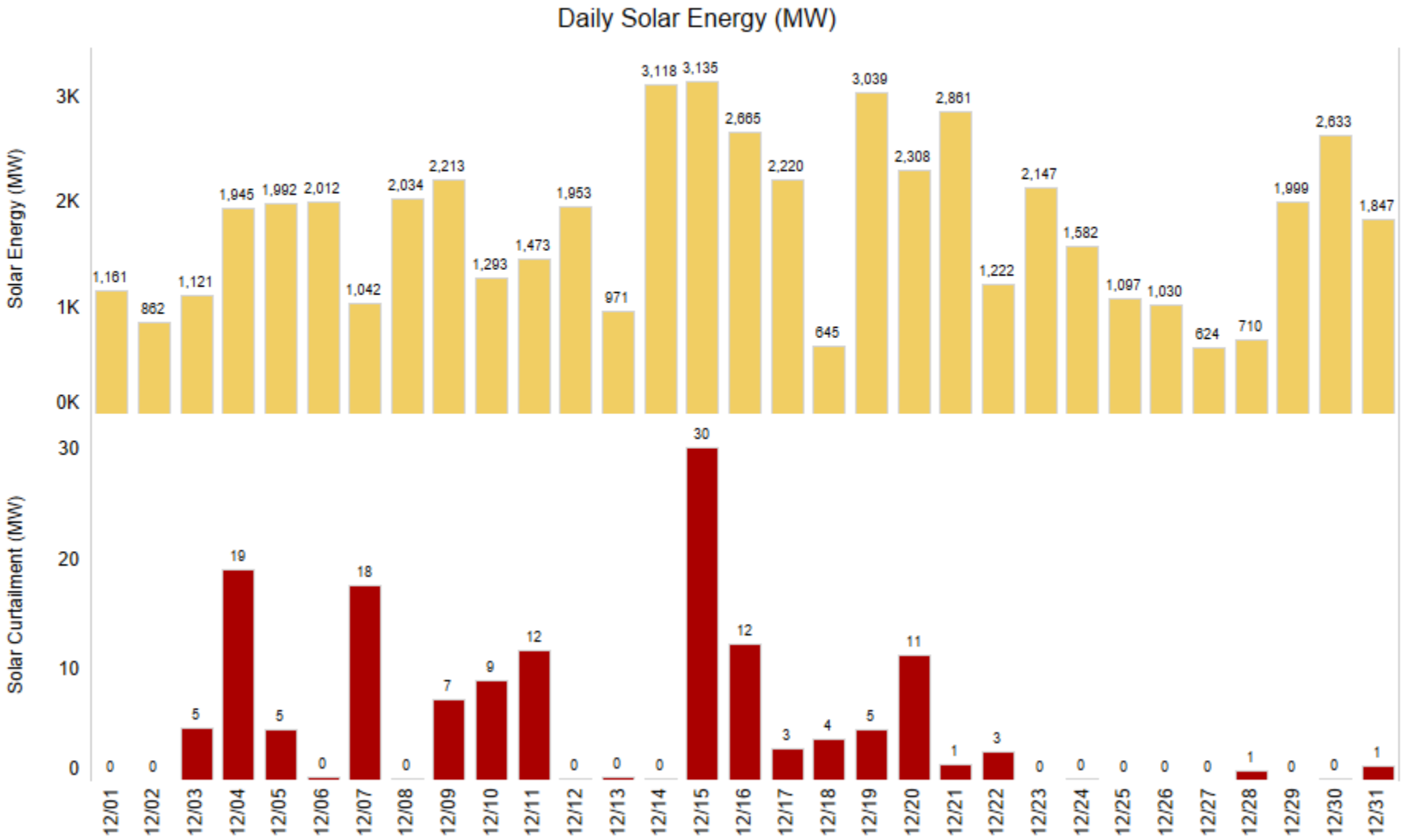
As of 09/05/2025
Registered Solar Capacity = 20,436 MW; Inservice Solar Capacity = 15,223 MW
Registered DIR Capacity = 20,264 MW; Inservice DIR Capacity = 15,051 MW



Peak Solar Date and Hour Ending	Dec-24 12/21 12	Jan-25 1/20 12	Feb-25 2/21 12	Mar-25 3/22 15	Apr-25 4/16 14	May-25 5/31 13	Jun-25 6/22 11	Jul-25 7/1 12	Aug-25 8/3 11	Sep-25 9/7 11	Oct-25 10/9 15	Nov-25 11/3 16	Dec-25 12/14 15
Peak Hour Solar Output (MW)	6,898	8,308	11,360	12,061	12,342	13,366	12,872	13,129	13,821	14,315	13,673	12,914	11,036
Peak Solar Output as a % of MISO Load in that hour	8.7%	8.4%	12.4%	18.8%	18.0%	19.2%	12.9%	13.3%	18.6%	22.2%	17.9%	18.3%	12.7%
Solar Energy as a % of MISO Energy	2.0%	2.6%	3.5%	6.0%	5.4%	6.0%	6.0%	5.5%	6.3%	6.2%	5.4%	3.6%	3.5%
DIR Dispatch below MAX as a % of avail. DIR	-3.1%	-1.9%	0.1%	1.1%	0.5%	-0.1%	-0.1%	-0.4%	-0.1%	0.8%	1.5%	0.7%	1.0%

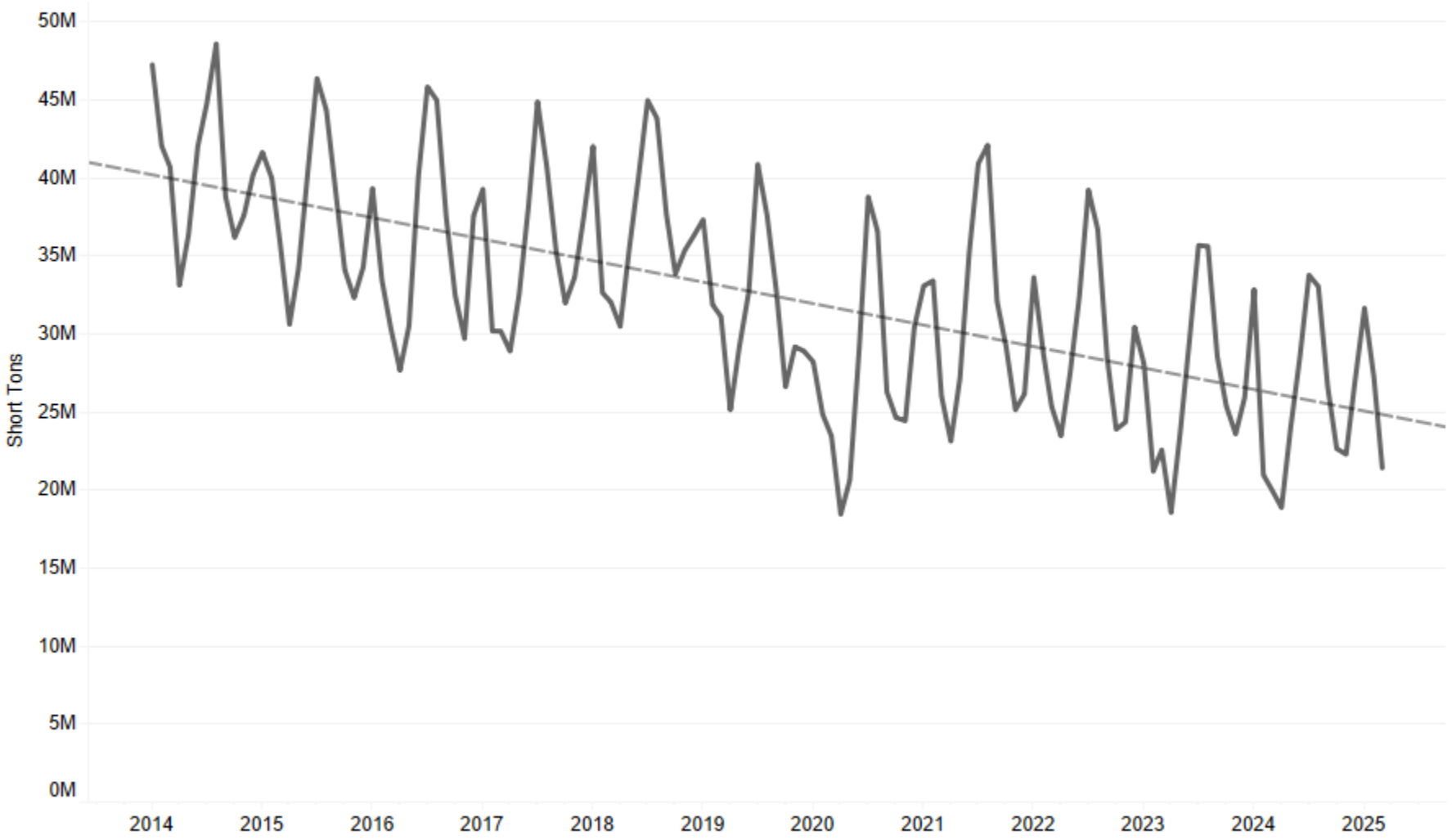
*Hourly State Estimator data
Source: MISO Forecast Department

Daily Average Solar Energy and Curtailment



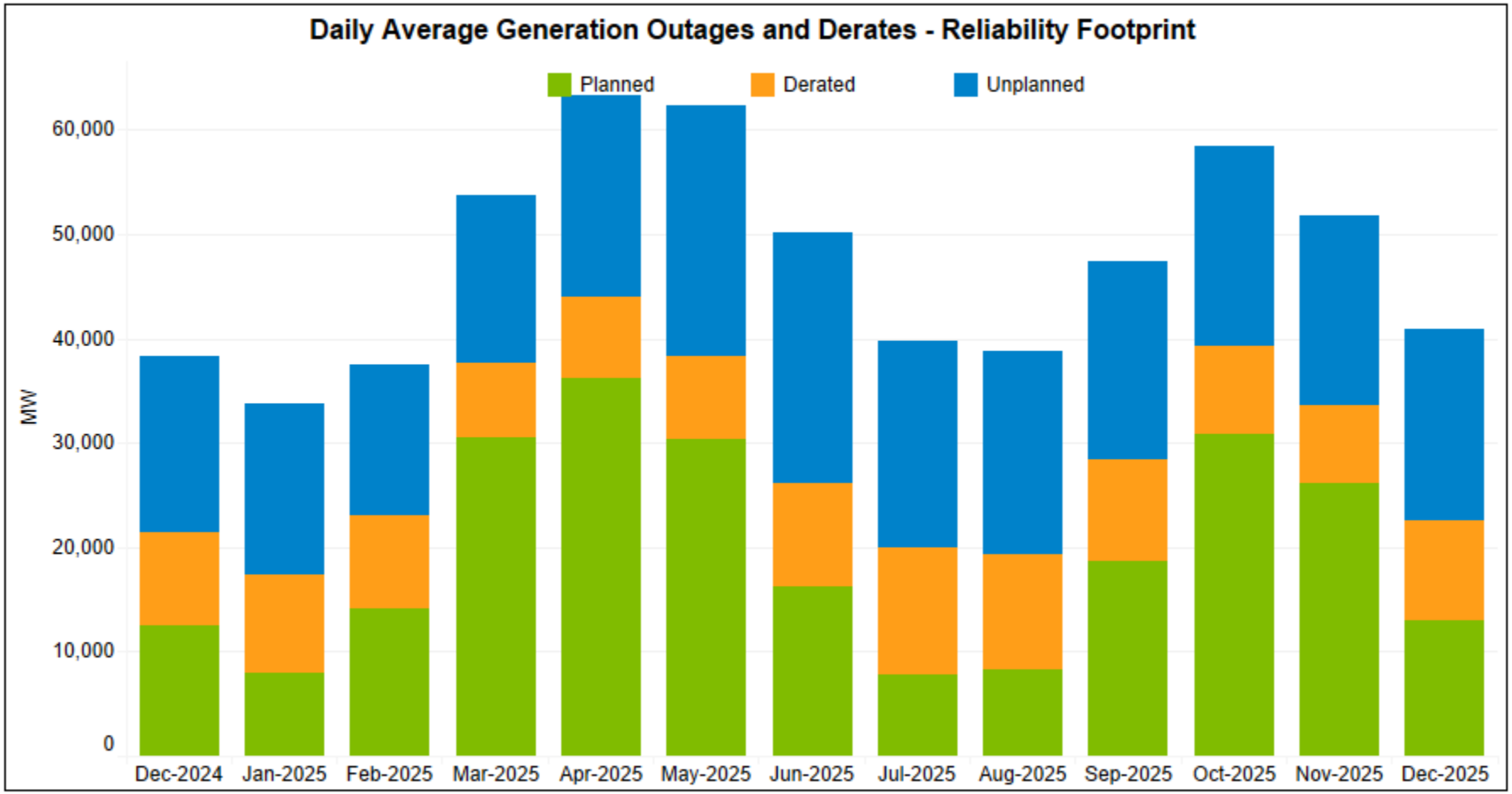
Source: MISO Market and Operations Analytics Department

Carbon Emissions



Data Source: EPA emissions through March 2025 and EPA EIA-860 2023
Emissions generated from MISO generators and does not account for volume of imports or exports
One Short Ton = 2000 lbs

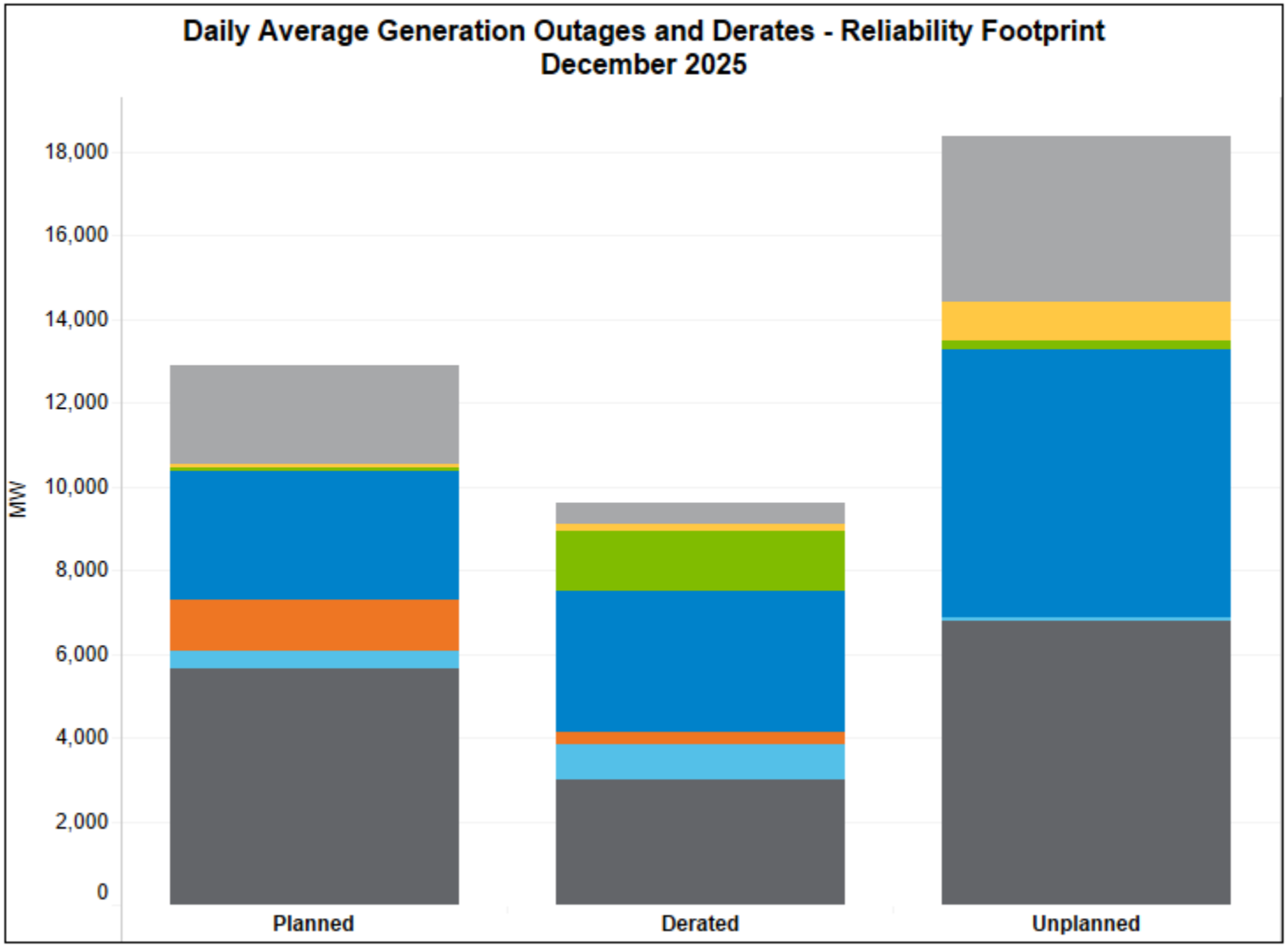
Generation Outages and Derates



Notes:
- *Unplanned Outages include Emergency, Forced, and Urgent*
- *Planned Outages include Planned*
- *De-rates are based on limits observed in Real-Time and may not reflect normal seasonal de-rates or de-rates for maintenance or other operating conditions*

Outage data is "point in time" and can change; the chart reflects the data as it resided in the system on the date of extraction
Source: MISO CROW Outage Scheduler

Generation Outages by Fuel

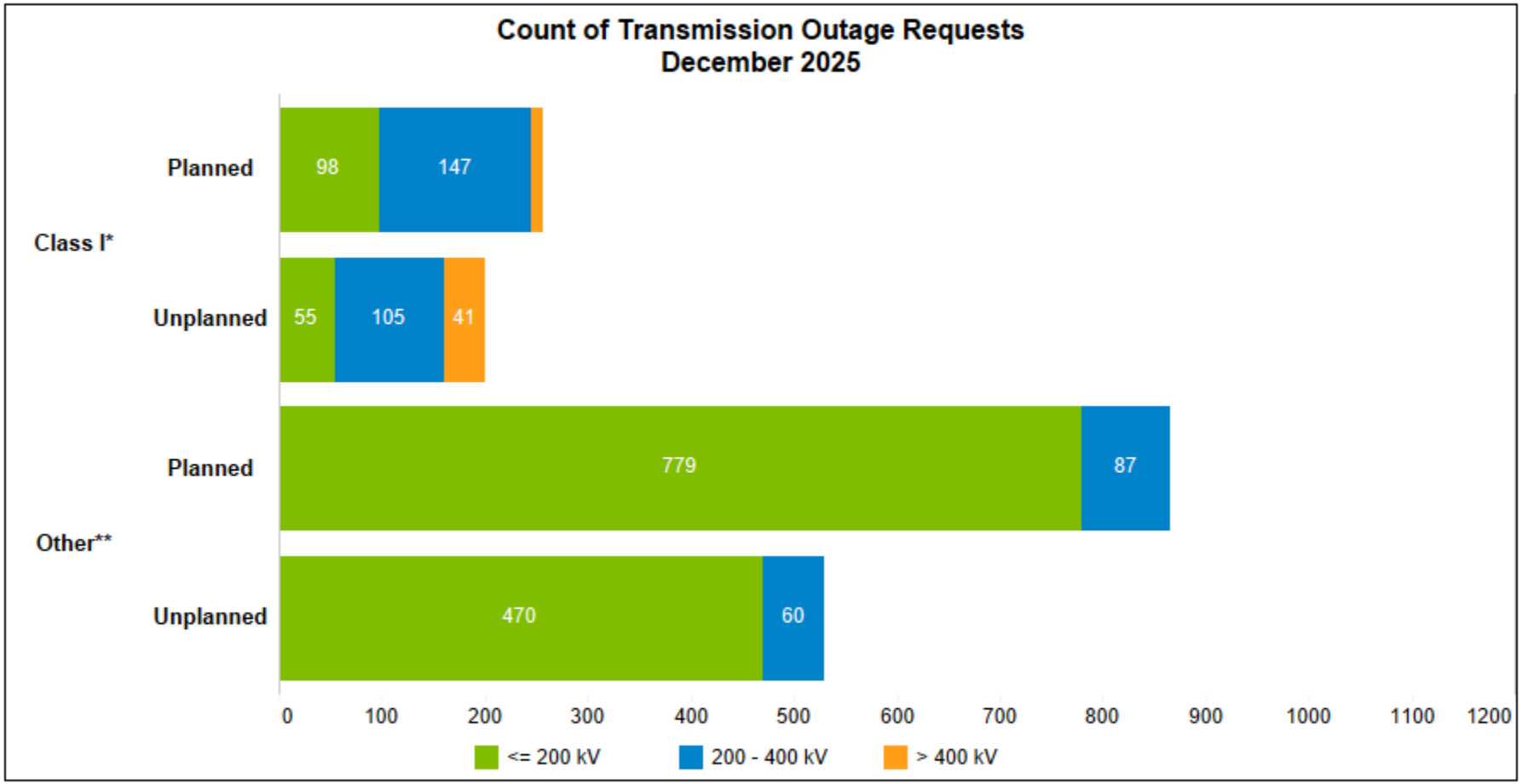


Notes:
- *Other includes Oil ,Hydro, Pet coke, Waste, BTMG, and units not in market footprint*
- *Unplanned Outages include Emergency, Forced, and Urgent*
- *Planned Outages include Planned*
- *De-rates are based on limits observed in Real-Time and may not reflect normal seasonal de-rates or de-rates for maintenance or other operating conditions*

Coal
Hydro
Nuclear
Gas
Wind
Solar
Other

Outage data is "point in time" and can change; the chart reflects the data as it resided in the system on the date of extraction
Source: MISO CROW Outage Scheduler

Transmission Outages



Notes:
- *Class 1 is any facility which has a reliability or market impact on transmission system operations*
- *Other is any facility which does NOT have a reliability or market impact on transmission system operations*
- *Unplanned Outages include Emergency, Forced, Discretionary and Urgent*
- *Planned Outages include Planned, Opportunity*

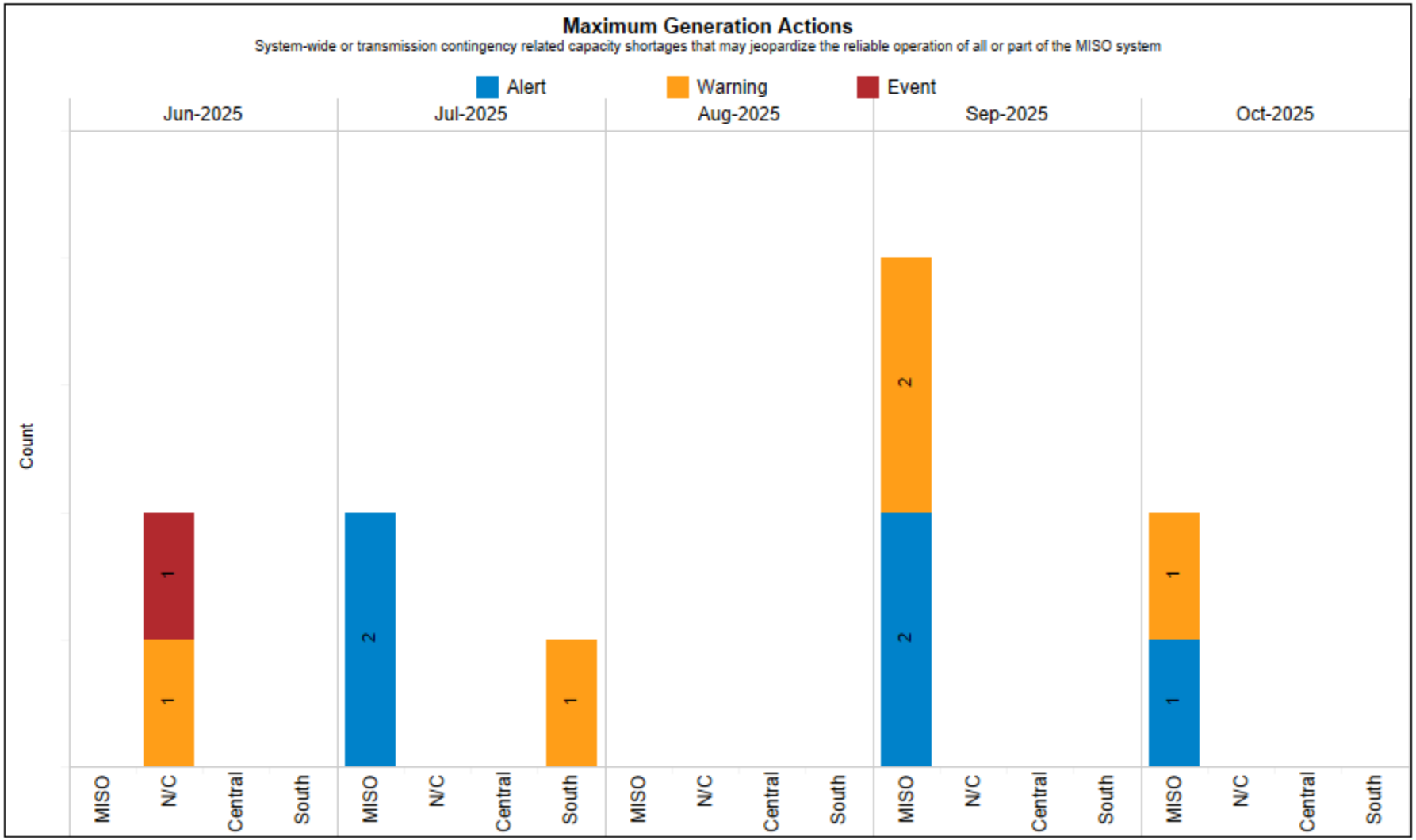
Outage data is "point in time" and can change; the chart reflects the data as it resided in the system on the date of extraction
Source: MISO CROW Outage Scheduler

MISO Inadvertent Balance

Month/Year	Net	On-Peak	Off-Peak
6/1/2024	-21,123	-10,382	-10,741
7/1/2024	-33,949	-12,863	-21,086
8/1/2024	-39,602	-15,448	-24,154
9/1/2024	-79,156	-36,769	-42,387
10/1/2024	-37,833	-17,446	-20,387
11/1/2024	-5,440	-2,237	-3,203
12/1/2024	-1,006	624	-1,630
1/1/2025	11,913	7,358	4,555
2/1/2025	23,852	17,127	6,725
3/1/2025	7,992	6,344	1,648
4/1/2025	22,512	14,664	7,848
5/1/2025	17,582	13,320	4,262
6/1/2025	9,239	6,344	2,895
7/1/2025	14,390	7,661	6,729
8/1/2025	-3,938	-5,525	1,587
9/1/2025	5,618	1,997	3,621
10/1/2025	23,968	9,295	14,673
11/1/2025			
12/1/2025			
Running Total from 2024	-84,981	-15,936	-69,045

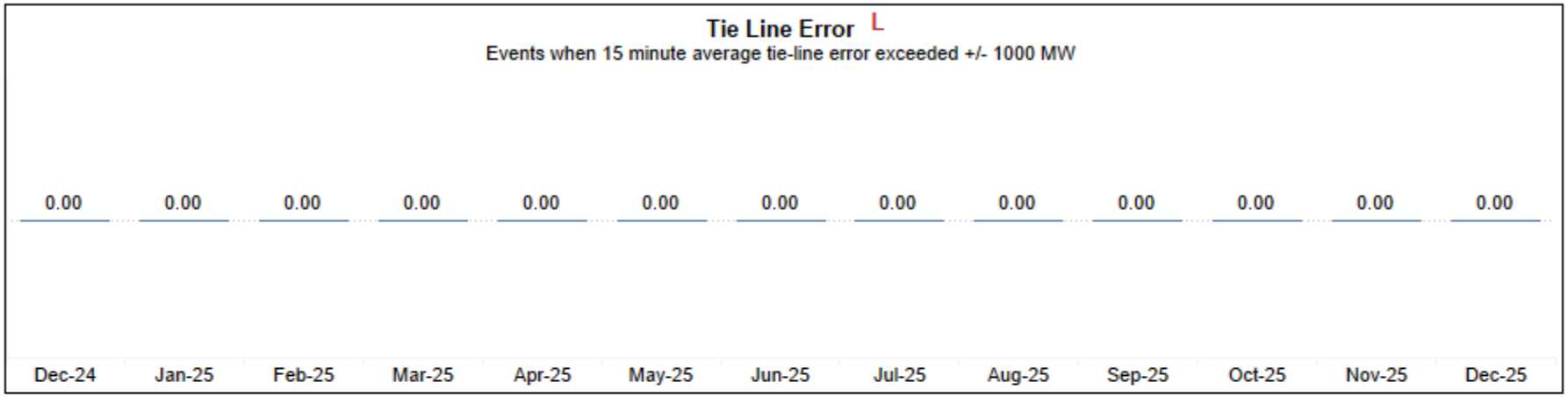
Source: NERC Tool (As of November 30, 2025)

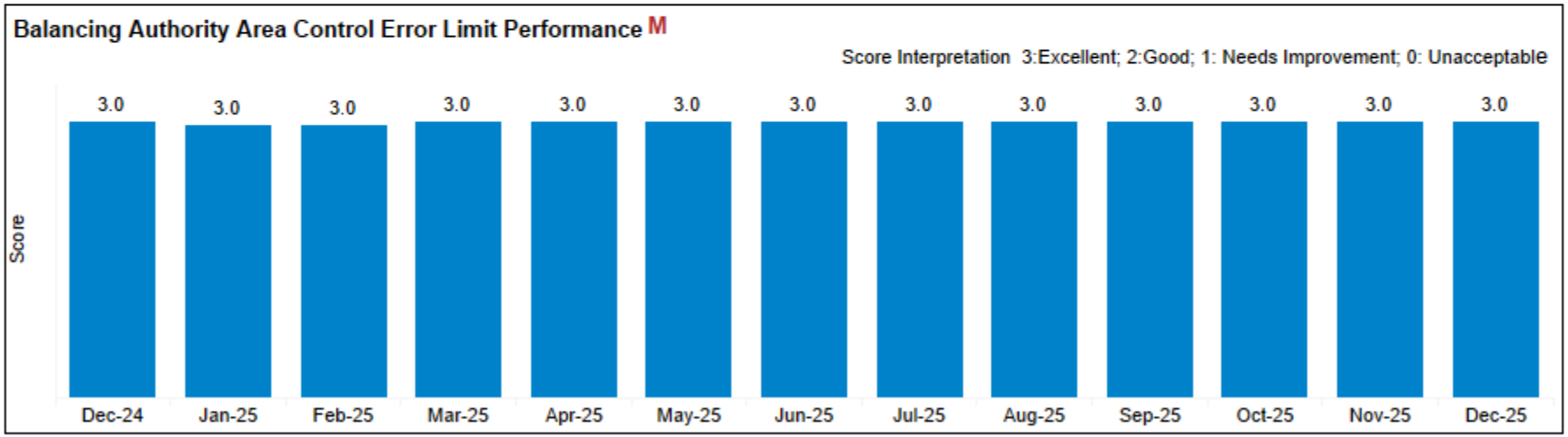
Generation Notifications



* Alerts – forecasting specific emergency situations in a future time-frame
* Warnings – experiencing initial stages of an emergency situation and taking action
* Events – experiencing an emergency situation and taking action

Tie Line and BAAL Performance

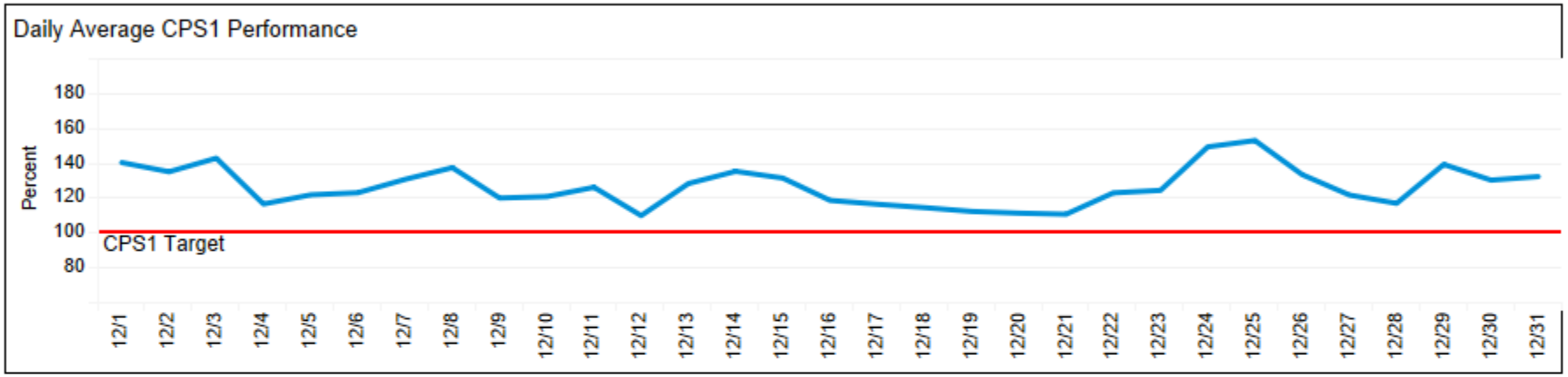


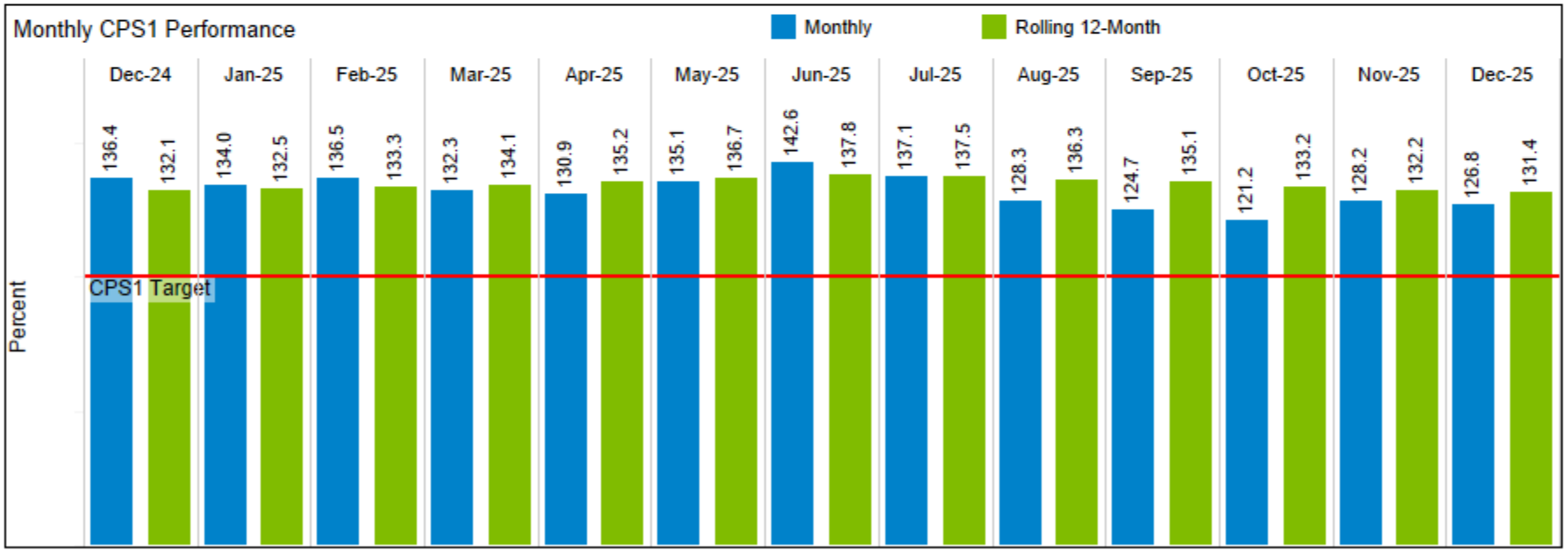


The Balancing Authority Area Control Error Limit (BAAL) measures control performance over the short-term. Exceeding BAAL for a continuous time period greater than 30 minutes constitutes a non-compliant event. The daily MISO BAAL performance rating is the lowest scored incident of the day.

Source: MISO Real-Time Operations Department

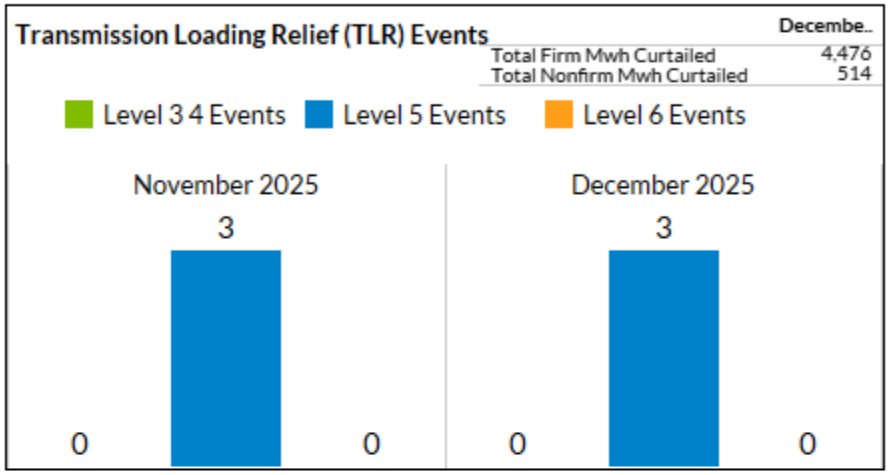
CPS1 Performance

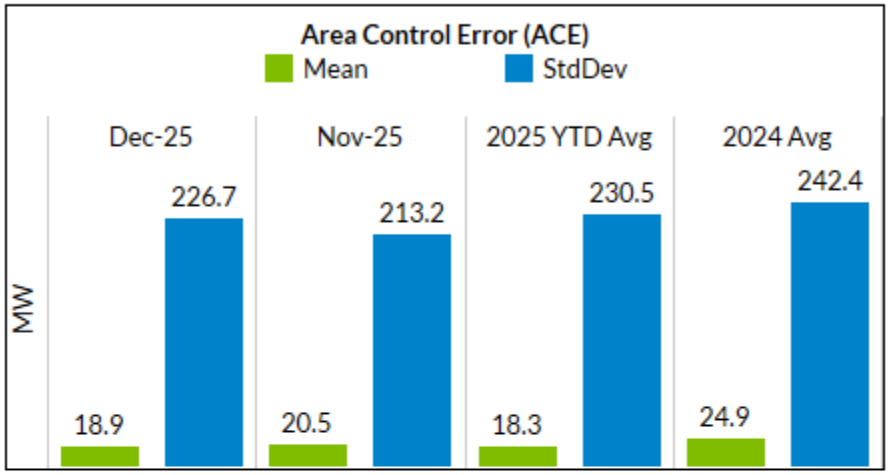


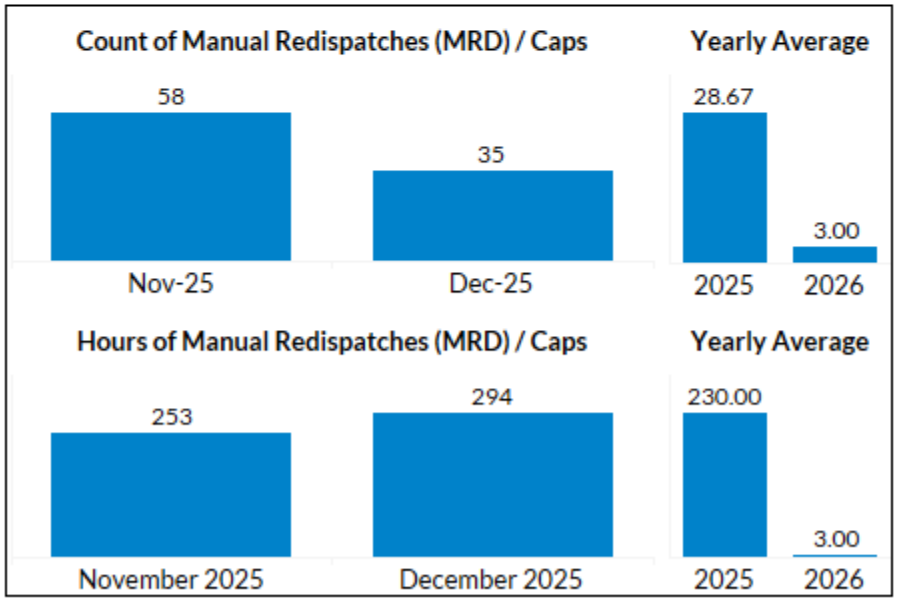


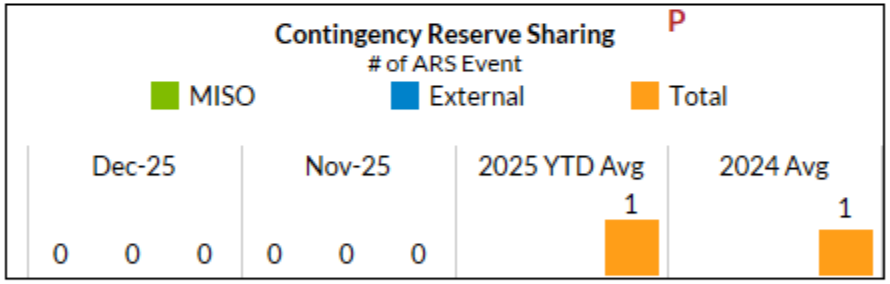
Per NERC Standard BAL-001-0 and MISO OP-044, the MISO will monitor CPS 1 performance and implement actions to ensure the MISO's rolling 12-month CPS 1 performance exceeds 100%
Source: MISO Real-Time Operations Department

Reliability — Other Metrics







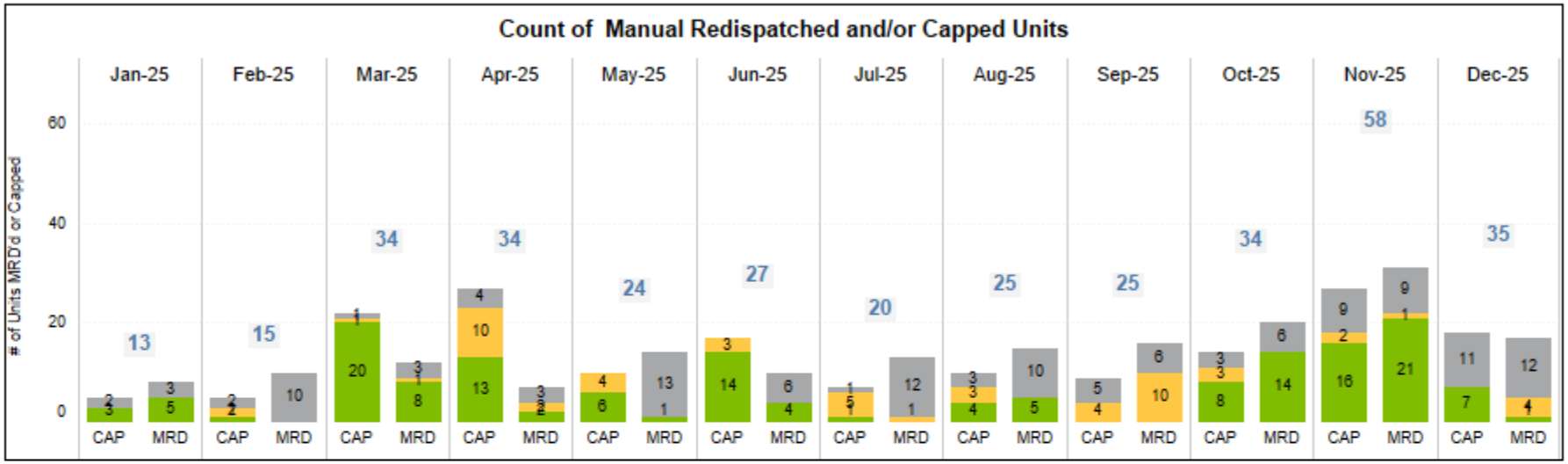


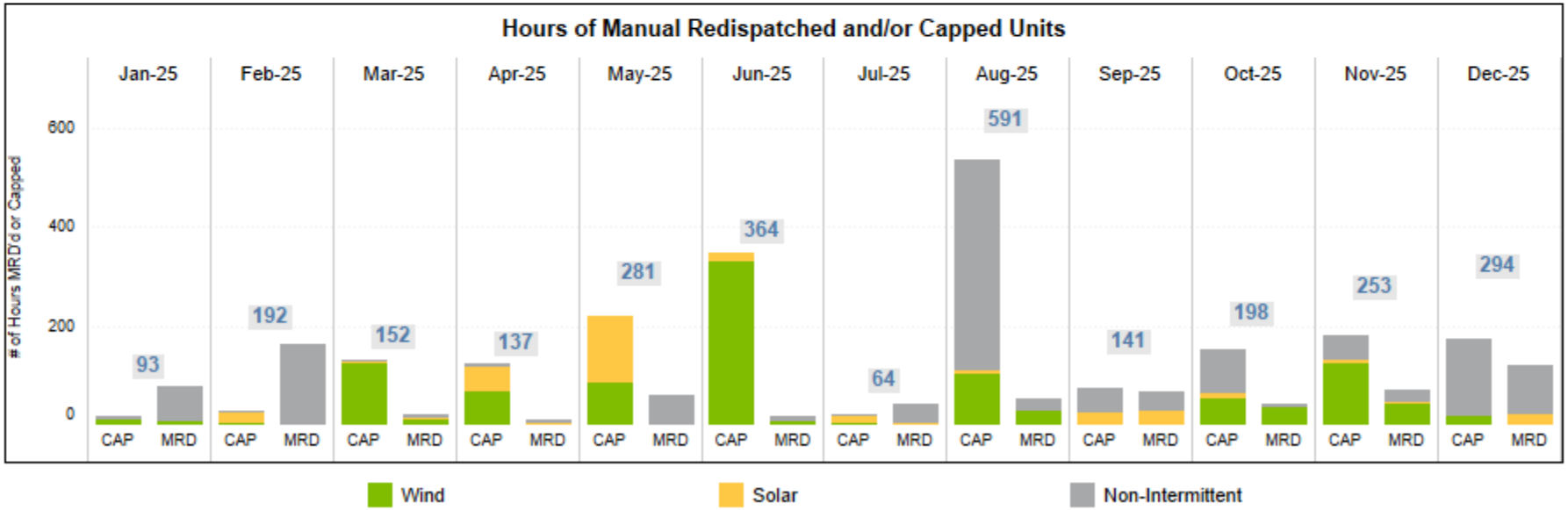
MISO deployed Contingency Reserves **

Source: MISO Real-Time Operations Department

**Historical Contingency Deployment data located in *Related Documents* at https://cdn.misoenergy.org/202001-202103%20Additional%20Inform...

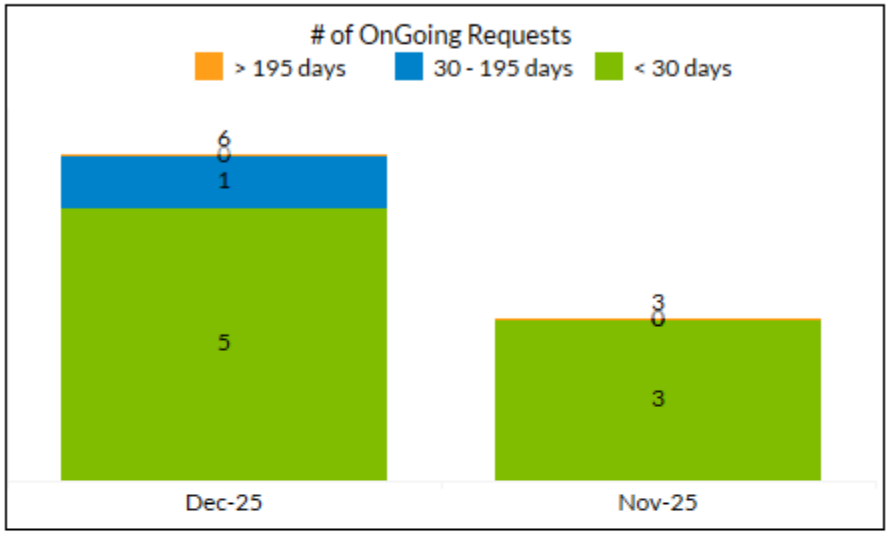
Operator Actions - Manual Redispatch and Caps

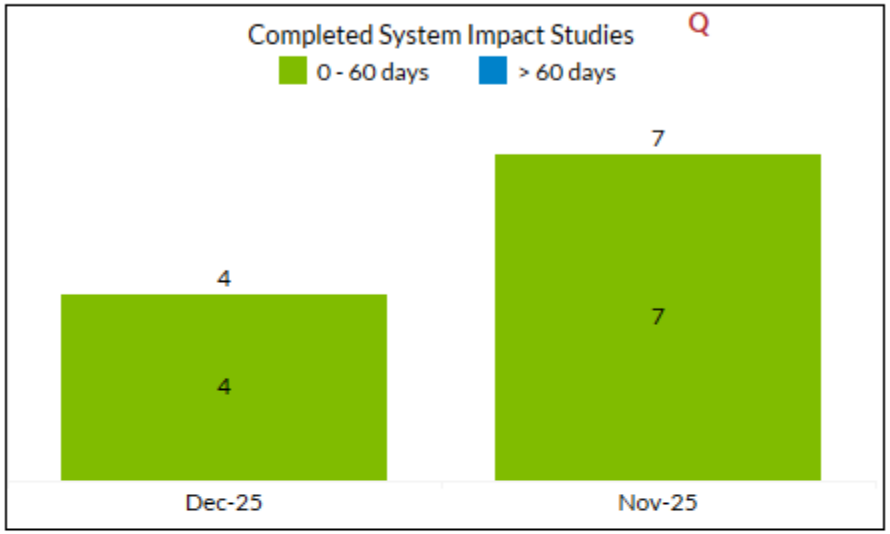


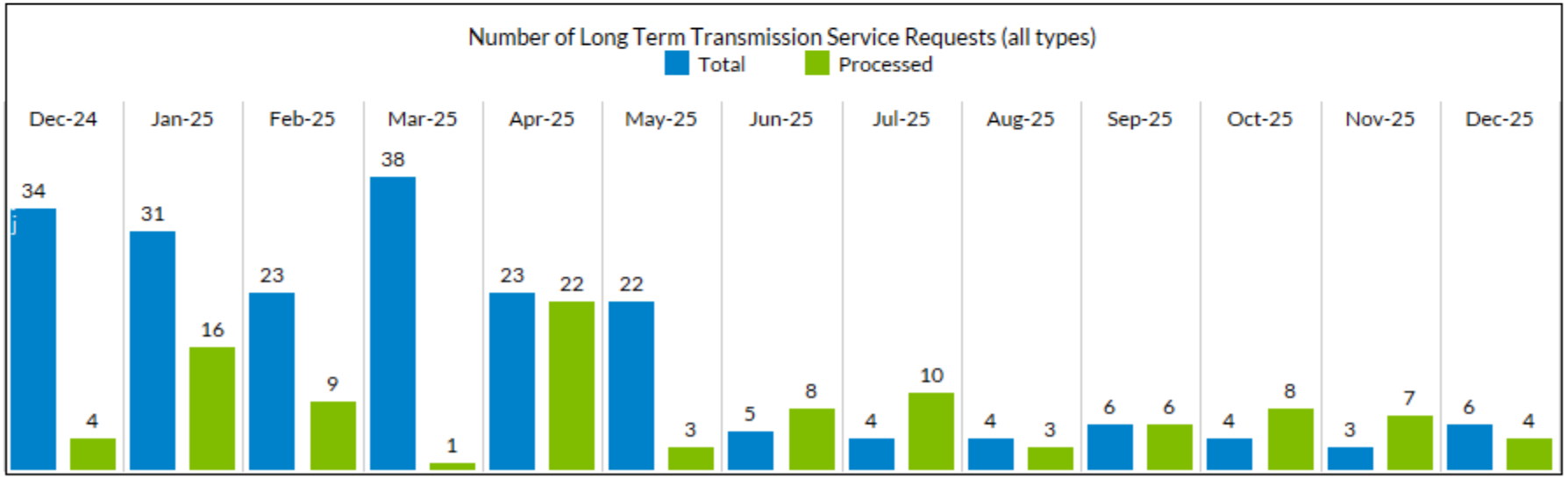


Source: MISO Market and Operations Analytics Department

Transmission Service Request

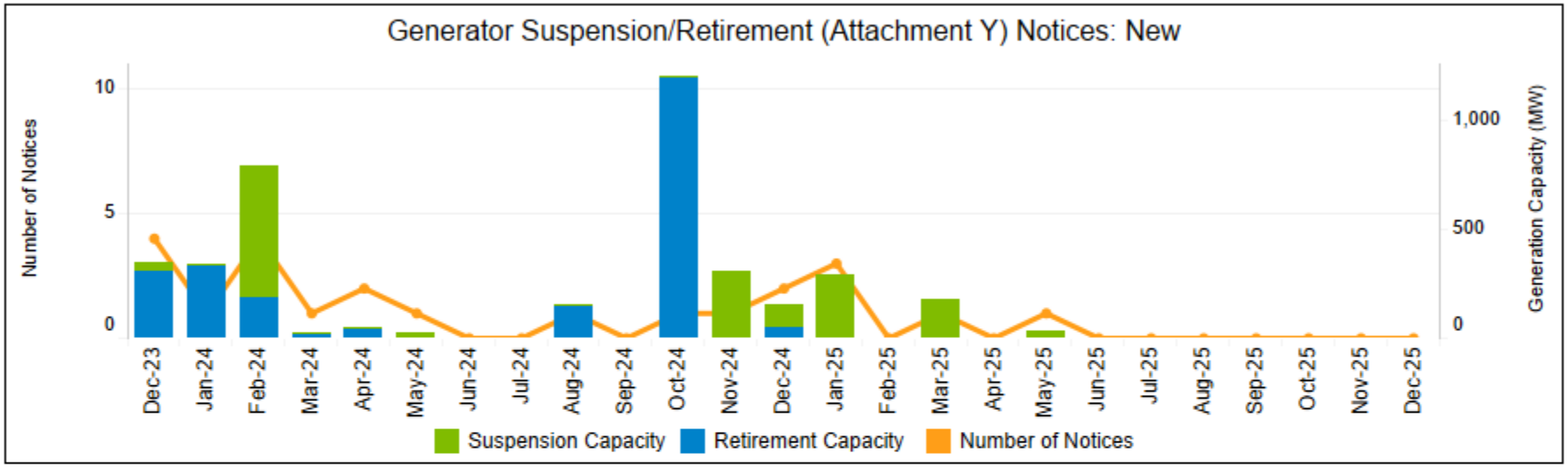


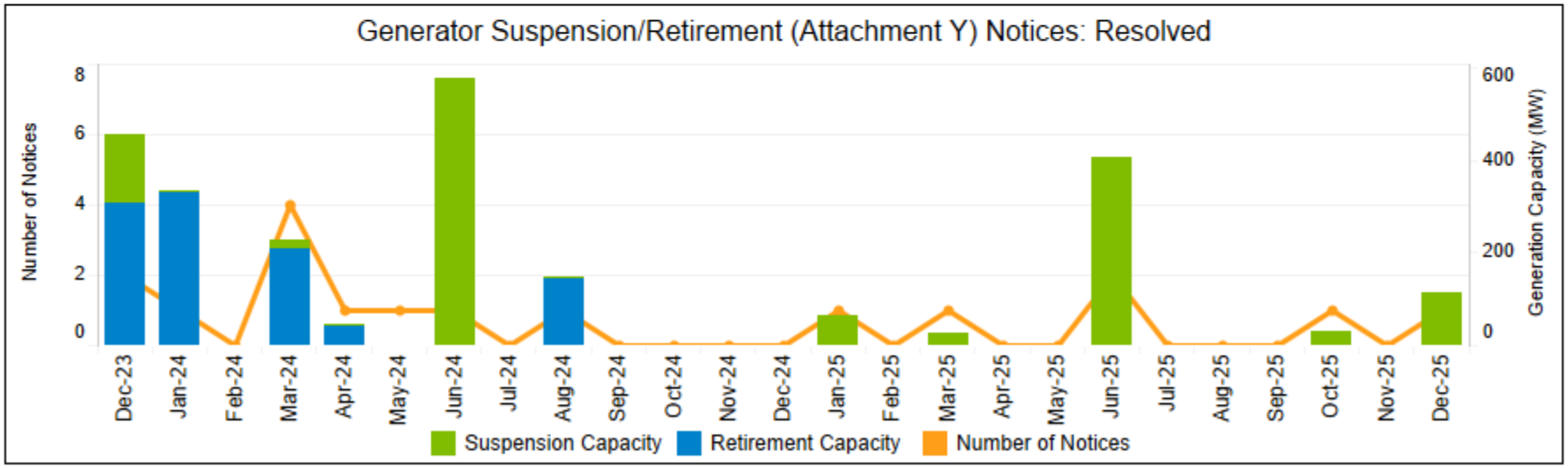




Source: MISO Resource Utilization

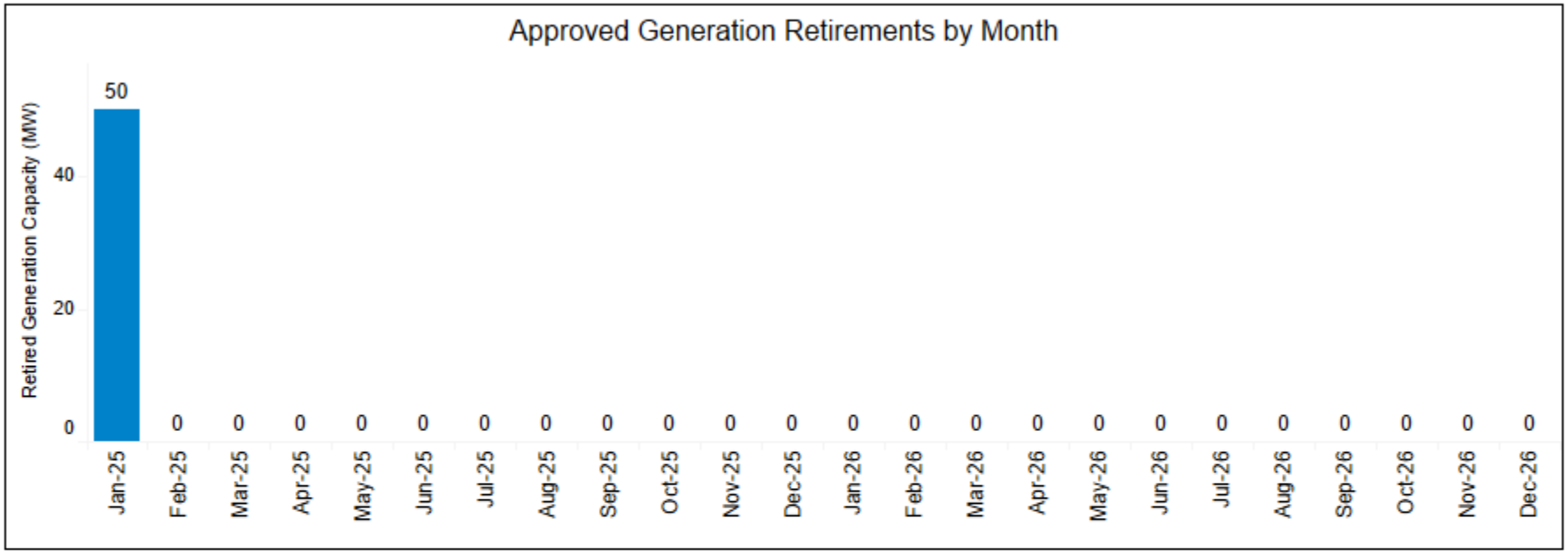
Generator Suspension/Retirement - New and Resolved

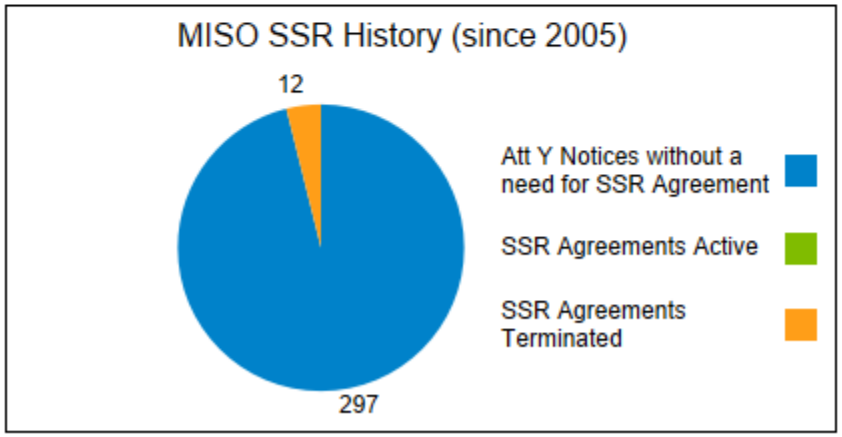




Source: MISO Transmission Planning Department

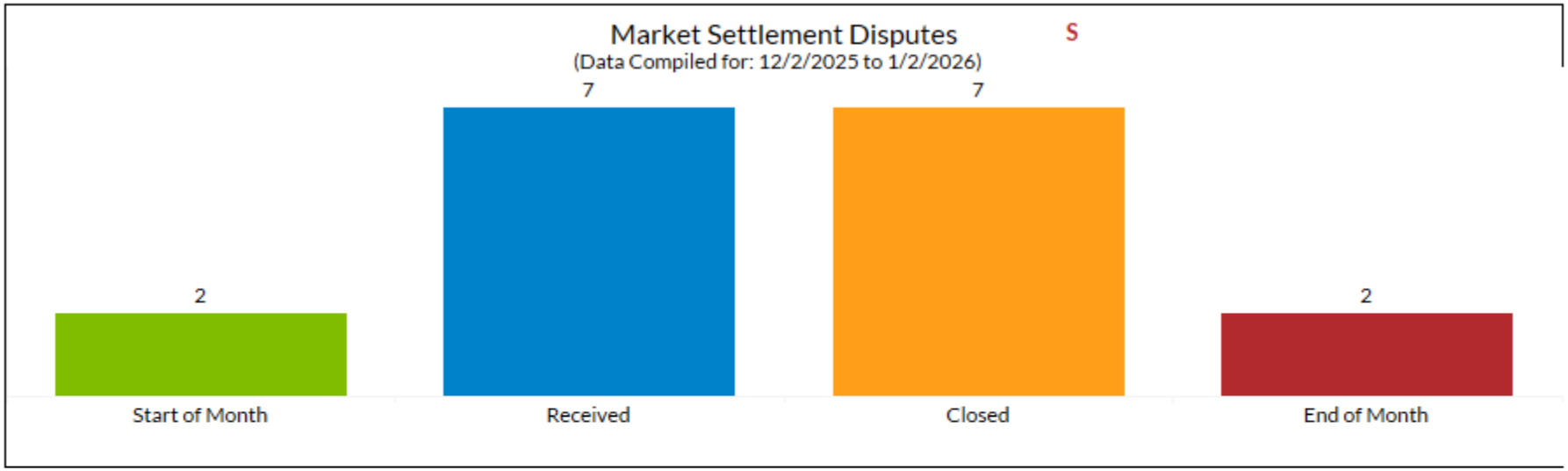
Generator Suspension/Retirement - Overall

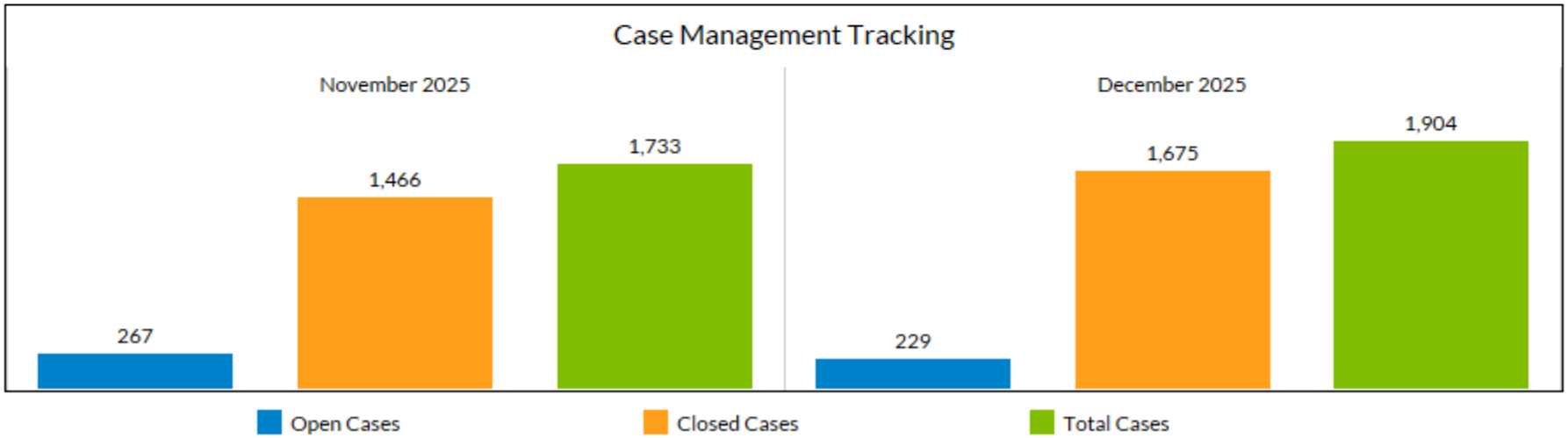




Source - MISO Transmission Planning Department

Settlements/Client Services and Readiness





Source: MISO Settlements and Client Services and Readiness Departments
Settlement values may change due to resettlement
Resource Adequacy, Tariff Pricing, Market Settlements, and Credit cases are included in Case Management Tracking data

The Technology Committee reviews the performance requirements for system availability, and the results are evaluated in the Human Resources Committee

2025 Metrics

Short-Term Incentive Metrics	JAN25	FEB25	MAR25	APR25	MAY25	JUNE25	JULY25	AUG25	SEPT25	OCT25	NOV25	DEC25	YTD	Threshold | Target | Excellent
Critical Systems Availability (Downtime in Hours)	0	0	1.5	0	0	0.1	0	0	0	0	0	0	**1.6**	4 Hours | 3 Hours | 2 Hours
Number of Critical System Incidents Exceeding 30 Minutes	0	0	1	0	0	0	0	0	0	0	0	0	**1**	2 | 1 | 0

Other Availability Metrics	JAN25	FEB25	MAR25	APR25	MAY25	JUNE25	JULY25	AUG25	SEPT25	OCT25	NOV25	DEC25	Monthly Target
ICCP (Availability %)	100	100	100	100	100	100	100	100	100	100	100	100	99.5
Customer Facing Applications – Portals (Availability Index)	10	10	10	9	10	10	9	10	10	10	10	10	10 of 10
Markets (Availability Index)	4	4	4	4	4	4	4	4	4	4	4	4	4 of 4
Reliability Targets (Availability Index)	3	3	3	3	3	3	3	3	3	3	3	3	3 of 3

**Trend lines represent quarter-over-quarter performance*
***ICCP = Inter-Control Center Communications Protocol*

2025 Dashboard Metric Criteria (1 of 2)

**New or revised 2025 Metric*

Operational Excellence									
Metric	**Chart**	**● Expected**	**■ Monitor**	**▼ Review**	**Metric**	**Chart**	**● Expected**	**■ Monitor**	**▼ Review**
Percentage Price Deviation*	A	Absolute DA-RT price difference divided by DA LMP <=28.6%	Absolute DA-RT price difference divided by DA LMP is >28.6% but <=34.3%	Absolute DA-RT price difference divided by DA LMP >34.3%	Unit Commitment Efficiency*	H	>=93%		<93%
Monthly Average Gross Virtual Profitability*	B	Within the standard deviation bands (threshold $0.44/MWh)	Outside the standard deviation bands		Real-Time Obligation fulfilled by Day-Ahead Supply at the Peak Hour	I	>=95%	>=93% but <95%	<93%
FTR Funding	C	Monthly FTR Allocation % is >=92% and YTD FTR Allocation % is >=96%	Not in good status AND Monthly FTR Allocation % is >=87% AND Rolling 12-month FTR Allocation % is >=93%	Not in Good AND not in Monitor status	Day Ahead Wind Generation Forecast Error	K	# of days that the hourly average forecast error exceeds 10% <= 6	# of days that the forecast error exceeds 10% >6 or Forecast error exceeds 15% in = 3 days	# of days that the forecast error exceeds 10% >8 or Forecast error exceeds 15% in > 3 days or Forecast error resulted in declaring 1 Real Time Event
Market Efficiency Metric	D	>= 95%		<95%	Day Ahead Solar Generation Forecast Error	T	# of days that the hourly average forecast error exceeds 10% <= 6	# of days that the forecast error exceeds 10% >6 or Forecast error exceeds 15% in = 3 days	# of days that the forecast error exceeds 10% >8 or Forecast error exceeds 15% in > 3 days or Forecast error resulted in declaring 1 Real Time Event
RSG per MWh to Energy Price*	E	<=0.38%	>0.38% and <=0.46%	>0.46%	Tie Line Error	L	<=1	>1 but <=3	>3
Day Ahead Mid-Term Load Forecast**	F	# of days that forecast error exceeds 3% <=6 AND # days that forecast error exceeds 4% <=4	# of days that forecast error exceeds 3% > 6 OR # days that forecast error exceeds 4%> 4 OR forecast error exceeds 6% on >= 1 day	# of days that forecast error exceeds 3% > 10 OR # days that forecast error exceeds 4%> 8 OR forecast error exceeds 7% on >= 1 day OR Forecast error resulted in declaring 1 Real Time Event	Control Performance – BAAL	M	Monthly performance score >=2	Monthly performance score<2 but >=1	Monthly performance score <1

FTR YTD metric is applied beginning April

*** Forecast errors observed in March, April, October and November will be measured by 1% lower thresholds*

2025 Dashboard Metric Criteria (2 of 2)

**New or revised 2025 Metric*

Operational Excellence									
Metric	**Chart**	**● Expected**	**■ Monitor**	**▼ Review**	**Metric**	**Chart**	**● Expected**	**■ Monitor**	**▼ Review**
Short-Term Load Forecast*	G	Forecast error exceeding the 95% percentile of forecast error for the past year <= 2 days	3 days <= Forecast error exceeding the 95% percentile of forecast error for the past year <= 5 days	Forecast error exceeding the 95% percentile of forecast error for the past year > 5 days	Control Performance – CPS1 and CPS1 12-month rolling	N	>=100%		<100%
					ARS Deployment	P	DCS monthly average % recovery (APR) = 100%	Analysis of event not yet complete	DCS monthly average % recovery (APR) confirmed <100%
Customer Service									
System Impact Study Performance	Q	Studies completed in less than 60 days >=85%	Studies completed in less than 60 days <85% but >=75%	Studies completed in less than 60 days <75%	Settlement Disputes	S	Increase of up to 20 disputes	Increase of between 20 and 50 disputes	Increase of more than 50 disputes

FTR YTD metric is applied beginning April
*** Forecast errors observed in March, April, October and November will be measured by 1% lower thresholds*
Two days in December 2022 have been removed from threshold calculations..

Exhibit 112

Counsel for Public Interest Organizations stated that this document was published in full, including the material labelled "Confidential" beginning on page 39, on December 13, 2024, on the website of the Federal Energy Regulatory Commission.

The previously published document can be found here:

https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20241213-5063&optimized=false&sid=1e90ede4-da17-4482-8e6d-e346192d0609 (click "Tab A" link within this webpage)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 112
Witmeier 2024 Queue Cap Testimony

TAB A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)**	**Docket No. ER25-___-000**

PREPARED DIRECT TESTIMONY OF ANDREW WITMEIER

ON BEHALF OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

November 21, 2024

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)**	**Docket No. ER25-___-000**

PREPARED DIRECT TESTIMONY OF
ANDREW WITMEIER

I. PROFESSIONAL BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, CURRENT POSITION AND YOUR BUSINESS ADDRESS.

A. My name is Andrew Witmeier. I am the Director of Resource Utilization for the Midcontinent Independent System Operator, Inc. ("MISO"). My business address is: 720 City Center Drive, Carmel, IN 46032-7574.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I joined MISO in 2003 after graduating from Purdue University with a bachelor's degree in electrical engineering. I spent the first 17 years of my career in various positions in MISO Operations. During that time, I worked as a North American Electric Reliability Corporation ("NERC") certified system operator in scheduling, engineering, and as a reliability coordinator. I also led several groups within MISO Operations as a manager in engineering, reliability coordination, and seams administration. In January 2020, I was appointed to my current position.

Q. PLEASE DESCRIBE YOUR JOB RESPONSIBILITIES WITH MISO AS THEY RELATE TO THIS FILING.

A. As the Director of Resource Utilization, I am responsible for the administration of MISO's Generator Interconnection Procedures ("GIP"), which are set forth in Attachment X of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff" or "MISO Tariff").[1] I oversee MISO's generation interconnection queue, including the negotiation and execution of Generator Interconnection Agreements ("GIAs"), which are based on MISO's *pro forma* GIA set forth in Appendix 6 of the GIP. I also oversee the group that manages and processes generation retirement, generator replacement, and Surplus Interconnection Service requests for generators connected to MISO's Transmission System. I have been directly involved in the preparation and development of the current proposals.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. I submitted testimony at the Federal Energy Regulatory Commission ("FERC" or "Commission") in Docket No. ER22-661-000 on issues related to MISO's generator queue reform and resource utilization and Docket Nos. ER24-340-000 and ER24-341-000 on additional issues related to MISO's generator queue reform and management.

II. OVERVIEW AND PURPOSE OF TESTIMONY

Q. ARE YOU SUBMITTING YOUR TESTIMONY ON BEHALF OF MISO?

A. Yes.

[1] Unless otherwise indicated in my Testimony, all capitalized terms used herein have the meaning as set forth in the Tariff or the proposed Tariff revisions, as applicable.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports the updated Tariff revisions that MISO is submitting in this docket to refile certain urgent quantity improvements to the GIP. As further discussed below, MISO's filing in this docket contains two severable proposals. While these proposals are separate from each other, both should be implemented as soon as possible to ensure that MISO's generator interconnection queue can continue to operate in a just and reasonable manner in the face of severe challenges precipitated by an ongoing and unprecedented increase in the number and volume of Interconnection Requests in MISO. The proposed changes will make MISO's administration of the queue more efficient and will improve MISO's compliance with the GIP timing requirements.

Q. HOW WAS THIS NEW PROPOSAL DEVELOPED?

A. MISO developed this updated proposal through a broad and inclusive stakeholder process. This filing incorporates the extensive stakeholder input we received in the past several months and reflects the lessons we learned from our previous queue reform efforts, including the Commission's guidance in Docket No. ER24-341-000. As discussed in more detail below, we have addressed the specific suggestions and concerns identified in the guidance order and have provided extensive opportunities for all interested parties to comment during the stakeholder review process. The final proposal that MISO is submitting today incorporates many of the comments and recommendations we have received in the process.

Q. HOW IS THIS FILING DIFFERENT FROM THE NOVEMBER 2023 CAP PROPOSAL?

A. MISO adjusted the formula for determining the cap, how exemptions will fit within the cap structure, and the types of exemptions presented in the current filing. With respect to the cap formula, the current proposal responds to the Commission's directives and opts for a more balanced, much simpler approach that relies on the MTEP power flow model to run the interconnection studies as the basis for the cap formula. The proposed cap formula will be 50% of the non-coincident summer peak values for each study region from the power flow model that will be used to perform the queue studies.[2] This percentage was chosen based on analysis performed by MISO that showed when queue volumes continue to rise above 50%, more Network Upgrades are required to mitigate congestion caused by new Interconnection Requests, offsetting substantially more existing generation. The purpose of a cap is to establish a more realistic dispatch that includes existing generation with new Interconnection Requests. This improved dispatch should result in less Network Upgrades, which reduces costs and reduces the need for additional facility studies and should therefore lead to faster processing and less dropouts. In light of the Commission's Order in Docket Nos. ER24-340-000 and ER24-341-000, MISO significantly modified the exemptions from its prior proposal. First, MISO removed the RERRA exemption. After special consideration of the comments and concerns brought forth by stakeholders and the Commission and the unique needs of RERRAs, MISO has committed to address RERRAs

[2] *Queue Improvements Cap Proposal* (October 16, 2024), https://cdn.misoenergy.org/20241016%20PAC%20Item%2006b%20Cap%20Proposal%20(PAC-2023-1)653144.pdf.

in a separate, newly proposed Expedited Resource Adequacy Study ("ERAS") process.[3] This new process will expedite the approval process of new generation needed to address state resource adequacy goals.[4] Second, addressing the Commission's earlier concerns regarding uncapped exemptions, MISO updated its queue cap formula to note that approved exemptions will be included in the number of Interconnection Requests needed to reach the 50% cap number. Put another way, approved exemptions will count towards the total MW queue cap of a given region. Third, any exemption must be elected at the time the interconnection application is submitted. This ensures the efficient implementation of the processing of the exemptions, less volatility in establishing the queue cap, and increases the levels of communication between MISO and stakeholders regarding when the queue cap is met. Finally, MISO is modifying the Provisional Generator Interconnection Agreement ("PGIA") exemption to stipulate that the PGIA exemption must be requested at the time of application. MISO determined that mandating an executed PGIA made it extremely difficult for Interconnection Customers to utilize this exemption for the reasons outlined above. Additionally, Interconnection Customers with a requested PGIA have assumed additional risks when their request for PGIA is made. While they are similarly situated to Replacement Generating Facilities or ERIS to NRIS conversions, MISO addressed PGIA specific concerns, such as when an Interconnection Customer can revert to non-provisional status.

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[3] *See Expeditated Resource Adequacy Study (ERAS) Introduction* (November 13, 2024), https://cdn.misoenergy.org/20241113%20PAC%20Item%2009%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Introduction660245.pdf;.

[4] *See Expedited Resource Adequacy Study (ERAS) Workshop* (November 18, 2024), https://cdn.misoenergy.org/20241118%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Workshop661622.pdf.

Q. PLEASE DESCRIBE WHY THE EXEMPTIONS, SITE CONTROL AND PAYMENTS ARE NOW REQUESTED WITH THE APPLICATION SUBMITTAL.

A. Following the Commission's Order on its first proposal, MISO reanalyzed its internal processes on how it would validate Interconnection Requests. MISO determined it was administratively inefficient to allow Interconnection Customers to retroactively request priority project status. Retroactive requests undermine the assertion that a project is truly a priority project. Retroactive requests can also unfairly game the limitation on a queue cycle. For example, under MISO's previous proposal, if a project learns that it will not be under the queue cap, then it could retroactively propose to enter into a PGIA in order to gain access to the next queue cycle. Under the previous proposal, that same project could later revert to non-provisional status with no penalty. Stakeholders expressed similar concerns. By adjusting the requirements for when an exemption must be declared and the requirements to maintain that exemption, MISO levels the playing field for all projects. These changes will necessitate that Interconnection Customers who want to make use of the PGIA exemption evaluate its project's feasibility and viability earlier in the process to determine whether they are willing to be bound by the PGIA commitments that make these projects more certain and justify their priority inclusion. This approach will allow MISO to efficiently process and prepare for a given Definitive Planning Phase ("DPP") Cycle. Additionally, MISO modified its proposal to notify its Interconnection Customers of the queue cap earlier in the process.

Q. PLEASE SUMMARIZE THE ADDITIONAL STAKHOLDER MEETINGS FOLLOWING THE ISSUES OF THE COMMISION'S REJECTION.

A. MISO re-engaged with the stakeholders and revised its initial cap proposal. The revised proposal was posted for stakeholder review and discussed in the Interconnection Process Working Group ("IPWG") and Planning Advisory Committee ("PAC") on multiple occasions. During these discussions, an alternative proposal ("Savion VPE proposal") was presented and subsequently voted on by stakeholders at the IPWG. Ultimately, the alternative proposal didn't receive enough votes to pass.

Q. PLEASE DESCRIBE THE BREAKDOWN OF THIS FILING.

A. MISO views the Queue Cap Proposal and the Exemptions to the Queue Cap Proposal as being two separate, but related, proposals included together in one filing for administrative convenience and Tariff version control. The Queue Cap Proposal is necessary and appropriate to address the unsupportable number of Interconnection Requests that MISO must process. It is a complete proposal in and of itself and does not depend on the approval of any of the exemptions to be complete or reasonable rate. While the Exemptions to the Queue Cap Proposal will necessarily depend on the acceptance of the Queue Cap Proposal, it is severable and a complete proposal. The Exemptions to the Queue Cap Proposal is intended as a standalone set of enhancements to the Queue Cap Proposal. While it is not necessary to make the cap function, the exemptions add independent value. Specifically, they allow the historically limited number of projects that have used PGIAs, sought ERIS to NRIS conversions, or sought to add additional interconnection service to a replacement facility to proceed directly into the next queue cycle in acknowledgement of the facts that these types of projects have proven highly certain given the level of commitment undertaken or the existing facilities. Even if the Commission determines the Exemptions to the Queue Cap Proposal does not adequately address the open access concerns identified

in its previous order, the state of the queue still necessitates a backstop queue cap to properly function, and the cap can function without the exemptions. I note that neither I nor my staff made any promises regarding whether the exemptions should be included in the cap filing or made any compromises to secure stakeholder support for the Queue Cap Proposal based on these exemptions. MISO commits to making a subsequent filing with the Commission to update the Tariff sheets to reflect the most up-to-date versions of the then-current Tariff provisions and within sixty (60) days of an order on each proposal is

Q. DID MISO ENGAGE THIRD PARTIES TO SUPPORT THE DEVELOPMENT OF THE PROPOSED REFORMS?

A. Yes. MISO hired Charles River Associates ("CRA") in early 2023 to perform an analysis of the MISO generator interconnection queue and to recommend changes to the process that would improve the quality of projects entering the queue, as well as MISO's ability to provide timely and consistent study results. CRA provided its findings in the stakeholder process and their final report is included as Exhibit 1 to my testimony ("CRA Report").

Q. DID MISO ADOPT ALL OF CRA'S RECOMMENDATIONS IN THIS PROPOSAL?

A. MISO adopted a significant number of CRA recommendations, with some adjustments. MISO adjusted the Proposals based on guidance of the Commission's Order in Docket No. ER24-341-000. These final proposals reflect the collaborative input from MISO, its stakeholders, and the additional CRA analysis on the need for a cap. An example of the CRA recommendation that was not included was to consider an individual developer cap on proposed projects, in addition to the overall MW value cap. The intent of this CRA recommendation was to provide a protection mechanism such that smaller developers are

not crowded out of the process by larger developers. This concept potentially could be necessary at some point in the future, but at this time MISO believes there is insufficient evidence to support a per-developer cap in the Queue Cap Proposal as needed.

Q. HOW DO THESE FILINGS RELATE TO MISO'S COMPLIANCE OBLIGATIONS UNDER ORDER NO. 2023/2023-A?

A. At the time of this submission, MISO submitted its Order No. 2023-2023-A compliance filings pursuant to the independent entity variation requirements set forth in Order No. 2003.[5] If the Commission accepts the proposed revisions, they will become part of the MISO Tariff. The proposal is submitted as a necessary independent entity variation to MISO's compliance with Order No. 2023-2023-A.

III. THE CURRENT STATE OF THE MISO QUEUE AND THE CONTINUED NEED FOR A CAP

Q. PLEASE DESCRIBE MISO'S INTERCONNECTION QUEUE PROCESS.

A. MISO's generator interconnection queue process generally follows the Commission's *pro forma* Large Generator Interconnection Procedures ("LGIP"), with changes and improvements adopted over the years pursuant to the Commission's independent entity variation. The current framework was put in effect in January 2017 as a result of extensive stakeholder driven reforms, which implemented a novel three-phase DPP structure to study Interconnection Requests, which since has been successfully adopted in some other regional transmission organizations ("RTOs"). MISO uses clusters to study

[5] *See Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

Interconnection Requests, with each calendar year producing one or two study clusters, known as "cycles." The clusters are studied on a subregional basis and, as I previously noted, MISO currently has five interconnection queue study regions.

Q. PLEASE EXPLAIN HOW THE THREE-PHASE DPP PROCESS WORKS.

A. The DPP structure provides for a sequential process to study Interconnection Requests in the queue. MISO conducts one System Impact Study ("SIS") in each of the three DPP Phases (*i.e.*, Preliminary SIS in DPP Phase I, Revised SIS in DPP Phase II, and Final SIS in DPP Phase III) to account for project withdrawals and to refine and update the analysis. Facilities Studies are conducted in DPP Phases II and III. The DPP process also includes three milestone payments—M2, M3, and M4, and provides for two designated off-ramps—Interconnection Customer Decision Points I and II ("Decision Points"). The first milestone payment, M2, is fixed at $8,000 per MW of Interconnection Service requested and is payable at entry into the queue. The second milestone, M3, is equal to the greater of twenty (20) percent of the amount of Network Upgrades identified in the Preliminary SIS less the amount previously posted as M2 or $1,000/MW. M3 is due at the end of Decision Point I. The third milestone, M4, is equal to 30 percent of the amount of Network Upgrades identified in the Revised SIS less than the amount previously posted as M2 and M3 payments. M4 is due at the end of Decision Point II. These milestones may be partially refundable upon withdrawal depending on the time of withdrawal and on whether they increase the Network Upgrade cost to other Interconnection Customers in the same cycle pursuant to a calculation of financial harm to other Interconnection Customers, as set forth in Section 7.8 of the GIP (*i.e.*, the "harm test"). The GIP also provides for penalty-free withdrawals in specified circumstances, as set forth in Section 7.6.2.4 of the GIP, less any

Automatic Withdrawal Penalty that was established in reforms approved by FERC in January 2024.6 The two off-ramps, Decision Points I and II, each last fifteen (15) Business Days and allow Interconnection Customers to review the study results from the most recent phase, pay the applicable milestone, and decide whether to proceed to the next DPP phase or withdraw from the queue.

Q. PLEASE DESCRIBE THE CURRENT STATUS OF MISO'S GENERATOR INTERCONNECTION QUEUE.

A. As of October 30, 2024, MISO's generator interconnection queue contained 1,706 active Interconnection Requests comprising of nearly 312 GW of proposed new generator interconnection capacity, which is a considerable backlog. This backlog is spread over all five queue study regions and includes queue cycles going back to 2019. It should be noted that when MISO previously made this cap filing in November of 2023, MISO's generator interconnection queue contained 1,371 active Interconnection Requests comprising nearly 236 GW of proposed new generator interconnection capacity. In contrast, MISO's peak load is only 127.1 GW and, as of December 2023, 191 GW of functioning total installed generation capacity already exists in the MISO Region.

Q. HOW DOES THE CURRENT QUEUE SIZE COMPARE TO PRIOR YEARS?

A. The current queue size is extraordinary and unprecedented. The most recent queue cycle, DPP-2023, alone is 124 GW. The two immediately preceding cycles, DPP-2022 and DPP-2021, were 170.8 GW and 76.8 GW, respectively. In contrast, the two cycles that started in 2017 following the implementation of the three-phase DPP process, DPP-2017-FEB and

6 *Midcontinent Indep. Sys. Operator*, 186 FERC ¶ 61,054 (January 19, 2024).
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DPP-2017-AUG, were only 30.7 GW, which generally is in line with the average queue cycle size in 2014-2016. It is important to note that the queue reforms approved by FERC in January 2024 did result in lower number of submitted projects. DPP-2023 had 30% less Interconnection Requests submitted than the amount of DPP-2022. However, the 124 GW in DPP-2023 is still as large as MISO's typical summer peak load. This shows that the previous reforms were not enough to facilitate a more efficient queue, and a MW cap is still necessary.

Q. WHAT IS THE CURRENT FUEL PROFILE OF THIS PROPOSED GENERATION?

A. Virtually all the proposed generating capacity in the latest queue cycles involves intermittent and weather-dependent resources, with solar facilities accounting for the lion's share of those.

Q. WHAT IS THE PERCENTAGE OF PROPOSED GENERATION IN THE MISO QUEUE THAT USUALLY GETS BUILT?

A. The CRA Report analyzed queue withdrawals in the latest queue cycles. *See* Exhibit 1 at 7-10. In the most recent completed cycles at the time of the report, DPP-2017-FEB, DPP-2017-AUG, and DPP-2018-APR, nearly 70% of the total generation capacity that entered these cycles was eventually withdrawn. *Id*. at 8-9. The remaining approximately 30% got their GIAs, but the actual MWs of generating capacity that will be constructed and energized will be less than 30% due to financial and construction stage challenges. Some of these GIAs have already been terminated, and various delays impacting some of the remaining GIAs will reduce the number of projects that achieve commercial operation still further.

Q. DO YOU EXPECT THE CURRENT QUEUE TRENDS TO CONTINUE?

A. Yes. I expect the queue to continue to grow in the next several years, with the bulk of the new proposed generating resources continuing to be intermittent and weather dependent.

Q. WHAT IS THE BASIS FOR YOUR EXPECTATION?

A. I attribute this trend to growing customer demand for renewable generation, the considerable financial incentives for renewable generation implemented in the *Infrastructure Investment and Jobs Act of 2021* and the *Inflation Reduction Act of 2022*,[7] and the backbone transmission MISO has approved, and plans to approve, through our Long Range Transmission Planning ("LRTP") effort. In July 2022, the MISO Board of Directors approved the first tranche of LRTP projects worth an estimated $10.3 billion of regional transmission facilities, which will provide access to the MISO grid for many new renewable resources. MISO anticipates a second tranche of projects to be approved in December 2024, currently estimated at $21.8 billion and known as LRTP Tranche 2.1. These contributing factors make a growth in Interconnection Requests very likely, and it is critical to implement the proposed reforms to ensure that MISO can manage the continuing growth.

Q. IF THE MAJORITY OF INTERCONNECTION REQUESTS IN THE QUEUE WITHDRAW, WHY IS THE CURRENT QUEUE GROWTH PROBLEMATIC?

A. The increasing number and volume of speculative Interconnection Requests in the queue strains MISO's resources and ability to process Interconnection Requests in accordance with the Commission's timing requirements and causes delays in the completion of required Interconnection Studies. This leads to increasing withdrawals, less certain DPP

Phase I and II study results, and ultimately, uncertainty and delays for all Interconnection Customers in the queue. Currently, queue delays are one of the largest contributing factors that negatively impact Interconnection Customers' ability to timely execute a GIA and, potentially, receive timely capacity accreditation under MISO's Resource Adequacy construct. Although cluster studies allow for multiple Interconnection Requests to be studied together, many administrative tasks required to process the queue are performed on an individual Interconnection Request basis. Such tasks include application processing to review modeling data, Site Control, and financial security and certain other tasks. Also, each Interconnection Request usually has one POI that requires its own individual studies, and each GIA is negotiated and executed individually.

Furthermore, independent from these timing challenges, the growth of the interconnection queue jeopardizes the ability of Interconnection Customers to receive study results that reflect actual system impacts, and the costs needed to mitigate them, especially in earlier phases of the DPP. To capture the actual impact of an Interconnection Request on the Transmission System, MISO must study that Interconnection Request at its full output, according to fuel-based dispatch assumptions, to establish the Network Upgrades needed to accommodate that request. Because a project is allowed to operate up to the service levels specified in its GIA, failure to capture the impacts of operating at such a level would artificially understate the impact of that project. This, in turn, can lead to overloads and other reliability cost problems if not mitigated, and cause cost shifts if the mitigations are identified in later studies for other projects. Thus, it is important to capture the full impact of a proposed project in an Interconnection Study. However, this becomes increasingly challenging when the amount of generation proposed in a queue cycle begins to exceed

projected peak load. Proposed generating facilities do not exist in a vacuum on MISO's system. In addition to what is proposed in a given queue cycle, there is existing generation already in commercial operation on the Transmission System and higher queued projects whose output must be accounted for in studies for new Interconnection Requests. When the total of this generation far exceeds load, MISO must use assumptions in order to develop a valid mathematical solution that will allow for a model that studies new generation at its authorized output while still sinking that power in the MISO region. MISO has some limited flexibility in model building to address these problems. However, the larger the queue size, the more aggressively MISO must adjust its assumptions to allow the model to solve (*i.e.*, to balance generation and load). Past a certain point, these assumptions begin to diverge sufficiently from reality and the model is no longer modelling how MISO's Transmission System and generation resources are expected to behave. The results of a study built on such models have diminished value because some existing generation will continue to dispatch well above the artificially lowered assumptions resulting in reliability issues on the Transmission System that were not studied. This, in turn, will require new studies in the interconnection process or in annual transmission planning studies resulting in potential cost shifts to future Interconnection Requests or to load, which creates risks and cost uncertainty for both existing and future projects, can lead to reliability issues on the Transmission System, and ultimately delays in deploying new generation. In short, assumptions diverging from expected conditions is a necessary result of study clusters that are too large to study under realistic system conditions, particularly when populated with increasing numbers of speculative Interconnection Requests. And, while Interconnection Customers will receive some "results" from these studies, those

results have a diminished value and, will ultimately cause more risk to the Transmission System and Interconnection Customers than study results based on cluster sizes that allow for realistic assumptions to be used.

Q. HAS MISO ATTEMPTED TO ADDRESS THESE CHALLENEGES WITHOUT LIMITING ITS QUEUE SIZE ?

A. MISO is continuously striving to improve its GIP. Following the introduction of the three-phase DPP in 2017, MISO made several targeted efforts to improve various aspects of the DPP process, such as milestone and penalty provisions, Site Control requirements, expedited processing options and other improvements, as summarized in the transmittal letters accompanying the MISO filings in the dockets. Nonetheless, no material changes have been made to the milestone amounts and penalty-free withdrawal provisions since 2017. Accordingly, the new challenges that have recently arisen require an urgent response and change to those GIP requirements. Additionally, MISO submitted and received approval for a set of queue reforms in early 2024 regarding increased financial payments and penalties along with increased site control requirements.

D. TRANSITION PROVISIONS

Q. IS MISO PROPOSING ANY TRANSITION PROVISIONS FOR THE REFORMS INCLUDED IN THE GIP IMPROVEMENTS FILING?

A. Yes, the transition provisions are included in proposed section 5.11 of the GIP. Generally, the proposed reforms will apply only to Interconnection Requests submitted in study cycles with application deadlines after the effective date of the reforms, starting with the DPP 2025 cycle. All preceding cycles will be exempt from the proposed changes.

IV. THE NEW CAP FILING

Q. PLEASE DESCRIBE THE UPDATED PERCENTAGE-BASED CAP MECHANISM.

A. The percentage-based load nature of the cap ensures that the studies are appropriately scaled to consider existing generation, new Interconnection Requests, and the load MISO serves while still enabling competition. The new queue cap formula is noted below:

*MISO study region cap = 50% * study region non-coincident summer peak*

The proposed cap formula will be 50% of the non-coincident summer peak values for each study region from the power flow model that will be used to perform the queue studies. MISO will use the most recent available MTEP model series. Open access is maintained as Interconnection Requests that are included in the cap are based on the timing of their request. This formula will ensure more reasonable study volumes and subsequently result in more certain study outcomes. The new proposed cap formula differs in three ways from the rejected cap formula. First, the new proposed cap formula uses non-coincident summer peak values while the original cap formula used non-coincident shoulder peak values. Second, the old cap formula utilized the Pmin value as floor to which existing generation can be turned down to accommodate to generation. The new cap formula does not. Finally, the old cap formula adjusted for estimated withdrawals and exemptions. MISO will review the need for a queue cap after three (3) years.

Q. WHY IS IT REASONABLE TO REQUIRE A 50% QUEUE CAP?

A. The 50% queue cap is reasonable because it allows MISO to balance the appropriate level of the interconnection queue size to ensure that Interconnection Requests are processed efficiently, increasing certainty for active projects and reduces the risk of future cost shifts,

while also addressing the base load needs of each study region. After numerous rounds of internal analysis, MISO determined that 50% of the non-coincident peak best strikes that balance. The analysis entailed performing iterative model builds at a reduced non-coincident peak value until the model could be built and solved without the need for Backbone Network Upgrades or needing exports to neighboring systems. This threshold was met at 50%. Backbone Network Upgrades are an indication that the model, before taking any contingencies, is in such a state that the power flow can't be solved without the addition of Network Upgrade(s). Typically, this is an indication of voltage collapse. Similar, exports to neighbors are indication of further Affected System costs. The internal analysis recommended that the appropriate level of the queue cap as well would be 50%**.** This would balance out the backbone upgrades to a reasonable level where it is appropriate to obtain a usable model and run the DPP studies from. MISO provides the results below based on that internal analysis:

Power flow model	**Total GW of Queue Projects**	**% of Non-Coincident Peak Load**	**Backbone Network Upgrades**	**Export to Neighbors (GW)**
2022 Cycle test cases	67.6	50%	0	0
2022 Cycle test cases	80.9	60%	0	0
2022 Cycle test cases	84.3	63%	0	10.2
2022 Cycle test cases	90.9	68%	1 Transmission line	12.2
2022 Cycle test cases	95.9	72%	1 Transmission line	15.0

2022 Cycle Kickoff	142.0	106%	21.5 GVAR of voltage support	6.4
2022 Cycle Prescreen	177.0	132%	3 Transmission lines 42.5 GVAR of voltage support	10.3

As noted in the chart, while the 60% test case did eliminate the need to make Backbone Network Upgrades under the previous formula, MISO also accounted for shoulder peak load and Pmin evaluation, which are no longer accounted for in the newly proposed queue cap formula. Based upon this evidence, MISO elected to move forward with the 50% cap value. This new formula represents a balance between MISO's need to efficiently manage the queue while also addressing regional load needs and open access concerns.

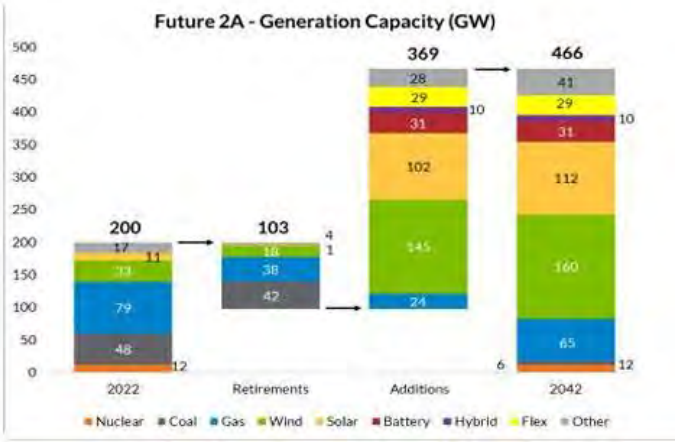
Q. WHY ARE THE PROPOSED CAP CHANGES STILL NECESSARY AND URGENT GIVEN THE EARLIER APPROVED QUEUE REFORMS?

A. While MISO noted that the increased GIP financial commitments and penalties along with updated site control evidence requirements that were approved in early 2024 resulted in a 30% reduction of "uncertain" interconnection applications from the previous cycle, it still represents a large number of projects for the team to study. Adding in the 2023 study cycle, MISO's current interconnection queue is sitting at roughly 312 GW. To put this into more context, MISO's all-time system peak load is 127 GW. Even with notable reductions of interconnection applications, the current interconnection service proposed in the queue is more than twice the all-time system peak load. This only further demonstrates purely qualitative improvements do not sufficiently increase in the queue size and ability to efficiently manage that queue. A MW limitation on individual interconnection queue

cycles will ensure that MISO can continue to produce more realistic resource dispatch, models, reduce queue timelines and produce lower Interconnection costs and therefore improving the success rate of the Queue, thereby increasing overall certainty in the interconnection queue. Additionally, MISO notes that the application portal is currently open and available for projects to be submitted into the next available study cycle; the cap is needed urgently to ensure that the appropriate balance of interconnection requests is processed in that study cycle.

Q. PLEASE DESCRIBE HOW THIS NEW PROPOSED CAP ADDRESSES THE COMMISSIONS EARLIER CONCERNS REGARDING FUTURE RESOURCE ADEQUACY NEEDS?

A. MISO re-engaged with its stakeholder to develop a proposal that would adequately address future adequacy needs. Per FERC's guidance, MISO reviewed the Future Planning Scenarios developed in conjunction with the Transmission Planning process("Futures"). MISO calls these scenarios "Futures," and they help MISO envision a set of possible resource adequacy outcomes up to twenty (20) years in the future. The scenarios establish a bookended range of economic, policy, and technological possibilities—such as load growth, electrification, decarbonization, renewable energy levels, generator retirements, fuel prices, and generation capital costs. The Futures hedge uncertainty by utilizing stakeholder information, policy direction, industry trends, and capacity expansion modeling to create the forecasts. Futures are updated with new or changing information. In reviewing the Futures 2A Planning Scenario, it was noted that 248 GW of Net Additions would be needed in the years 2025-2042 (17 years):



Taking this into account, MISO compared how the cap would impact this forecasted need.

Active Interconnection Requests in the Queue8	321 GW
Assumed completion rate of 21%	67.4 GW
Proposed Queue Cap	68 GW
Per Year additions (21% completion rate)	14.3 GW

Per the CRA report, using a historical completion rate of 21%, MISO estimates per year additions of 14.3 GW. From 2025 to 2042 and adding to the existing active Interconnection Requests already in the queue, this equates to 310 GW. Based on this analysis MISO believes there will be adequate throughput even with the cap to meet our future Resource Adequacy needs even with a queue cap of 50% of the non-coincidental peak load.

Q. PLEASE DESCRIBE HOW THIS NEW PROPOSED CAP FORMULA ADDRESSES THE COMMISSIONS EARLIER CONCERNS REGARDING EXEMPTIONS?

A. While limited in use given their inherent nature that minimize their submittals, MISO has found that projects related to increases in replacements, ERIS to NRIS conversions and PGIAs tend to reflect a greater commitment of the Interconnection Customer to the project and a lower withdrawal rate, leading to a greater level of certainty, given they are comprised of instances where an Interconnection Customer seeks to add incremental new service to an existing generating facility or have committed to a higher level of financial commitment. Given this criterion of existing generation facilities, MISO anticipates the continued limited use of these exemptions based on the inherent practical nature of these products that have historically limited their submittals. Additionally, in rejecting MISO's initial cap filing, citing the RERRA exemption, FERC noted an "uncapped exemption" potential that might undermine the benefits of having a cap in place. MISO ultimately found that the RERRA exemption engendered strong criticism from the stakeholders and the Commission, and the filing was ultimately rejected. Under the current proposal, MISO is amending Section 4.1.2 of Attachment X to remove the RERRA exemption. MISO has recognized that this as a more distinct queue issue that should be addressed in a separate filing. MISO has committed to working on addressing the needs of RERRA entities through a newly proposed ERAS process that will expedite the approval process of new generation needed to address resource adequacy. Furthermore, MISO has updated the cap formula to note that approved exemptions will be included with all projects that are used to meet the cap limit.

Q. DID CRA RECOMMEND A QUEUE CAP?

A. Yes. In fact, the CRA Report recommends two separate caps: (1) a queue cap per cycle; and (2) a per developer cap. *See* Exhibit 1 at 17-18. The CRA Report views a queue cap as a critical remedy to address the challenges outlined in my testimony. CRA recommended that MISO determine the level of the queue cap as well as its application across study regions, queue cycles and potentially individual entities. *Id*. at 17. The CRA Report further suggested that the following criteria could be considered in designing an appropriate queue cap: (1) peak load and forecasted peak load, (2) installed capacity, guaranteed additions, and expected retirements, and (3) reliability and resource adequacy. *Id*. at 18.

Q. WHAT ARE THE BENEFITS OF A STUDY CYCLE CAP?

A. The proposed cap will ensure that Interconnection Study results are based on a more realistic dispatch, thereby removing the need for prohibitively expensive and unrealistic Network Upgrades. Currently, Interconnection Customers receive realistic and informative study results only after enough projects exit the queue to achieve a realistic dispatch. The proposed cap will ensure more realistic and informative study results at an earlier point in the study process, without the delays and uncertainty caused by withdrawals after studies are performed with unrealistic Network Upgrade assumptions. The cap benefits Interconnection Customers by providing better cost estimates and a timelier study process. As discussed above, the cap also will provide benefits to the engineers performing these studies by improving their ability to solve these complex models and will reduce the amount of unnecessary engineering analyses, which are performed on a study model using unrealistic assumptions.

Q. WHERE WILL THIS CAP FORMULA BE STATED?

A. MISO will put the queue cap formula in the Tariff. In addition, MISO will post a report to its website prior to each study cycle describing the cap calculation and results.

Q. WILL MISO USE THE SAME FORMULA FOR POST-2025 QUEUE CYCLES?

A. MISO will continue to work with stakeholders to determine if the calculation should be modified for future cycles. MISO purposely used a simple calculation that more than adequately meets regional load needs. MISO also has committed to revisiting its cap-related Tariff provisions in three (3) years. MISO is willing to either provide an informational report discussing the effectiveness of these provisions after the third cluster study cycle or propose changes in a subsequent FERC filing based on the accumulated experience.

Q. HOW WILL MISO PROCESS APPLICATIONS ONCE THE CAP IS ESTABLISHED?

A. Once the cap amount has been calculated and posted, MISO will process the applications using a serial "first-come, first-served" approach based on when the applications were queued during the open application window. MISO will subsequently review the interconnection applications until the cap amount is reached. This process will provide an incentive to submit an Interconnection Request earlier in the open application window as opposed to right up until the application deadline as is often the case today. In addition, this process will have the added effect of "flattening the curve" for application submittals, *i.e.*, the projects would enter the queue when they are ready rather than wait until the last moment, thereby allowing MISO to manage the study cycle more efficiently. Meaning we expect projects to enter the queue when they are ready and will meet all necessary

requirements to secure their spot. MISO recognizes that this flattening of the curve will not hold true for the 2023 cycle, as it is expected that most applications will be submitted on the first day that MISO opens the web-based application tool to accept new applications.

Q. CAN YOU PLEASE EXPAND ON WHAT HAPPENS TO THOSE INTECONNECTION REQUESTS THAT FOUND TO BE "OVER THE CAP"?

A. Interconnection Requests that are processed after the cap has been met will continue to be evaluated by MISO to ensure they are valid requests, including necessary items such as milestones, Site Control, and modeling data. Once approved as valid, these Interconnection Requests will remain in the queue and will be studied in the next available queue cycle. Therefore, all Interconnection Customers, even those that are "above the cap", have comparable access to the interconnection process. A subset of the Interconnection Requests, i.e., those submitted closest to the time when the cap was met, can potentially replace projects that withdraw up to 30 days before the start of the DPP process. If a project that was under the cap withdraws, then MISO will pull the first project in the next cycle forward. This will be done up until the model needs to be built for the pre-screening analysis, which is 30 days before the start of the DPP process. This will allow 15 days to develop the model and post the pre-screening results, and then another 15 days for Interconnection Customers to review the analysis and determine if they should withdraw or remain in the queue and be included in the DPP process. Any dropouts that occur between the window when the pre-screening model is being developed and the start of the DPP process will not be replaced.

Q. CAN INTERCONNECTION REQUESTS IN THE QUEUE THAT ARE WAITING FOR THE NEXT CYCLE BE MODIFIED?

A. Yes, these Interconnection Requests will be able to make all the modifications allowable per section 4.4 of the GIP, which could include, but are not limited to: POI changes, MW reduction, removal of one fuel source for hybrids. Once these Interconnection Requests are included in a DPP study cycle, any changes will be evaluated as a potential material modification per Section 4.4.

Q. WILL DEVELOPERS KNOW THE MAXIMUM AMOUNT OF MEGAWATTS THAT CAN BE SUBMITTED IN A GIVEN QUEUE CYCLE?

A. Yes, the MW value for each DPP study cycle will be posted on the MISO public website at least ten (10) Business Days prior to the application deadline of that Definitive Planning study cycle. Additionally, MISO will post an associated whitepaper to the MISO public website to inform stakeholders how the cap was developed and set. It should be noted that as part of this process, MISO will be re-evaluating the formula prior to each study cycle, including the cap amount and the associated margins. There will be no cap on the number of individual requests any Interconnection Customer can submit. All applications will be evaluated against the cap on a "first come, first served" basis. This could result in an Interconnection Customer having a higher percentage of projects within any given queue cycle than another. If MISO determines this could create an unfair advantage over other Interconnection Customers, then MISO will develop an individual cap per Interconnection Customer and will file that tariff change with FERC for future queue cycles.

Q. IS MISO PROPOSING ANY EXEMPTIONS FROM THE QUEUE CAP?

A. Yes. MISO recognized in the early stages of development of its queue reform proposals the importance for a narrow set of Interconnection Requests to be included in a cycle if they already have an existing Generating Facility or Interconnection Service in place or otherwise exhibit a high level of certainty. These proposed exemptions are set forth in Section 4.1.2 of the GIP and include: 1) Interconnection Requests involving an increase in the capacity of an approved Replacement Generating Facility; (2) Interconnection Requests involving a conversion of ERIS into NRIS; (3) Interconnection Requests involving a Generating Facility with a requirement to request a PGIA. MISO initially proposed that these projects be exempt from the queue size limitations and other aspects of the initial proposal. In consideration of the concerns highlighted by the Commission, these projects will no longer be exempt from the queue cap limitations. However, as described herein, these projects will be exempt from certain requirements that will allow these exemptions to receive first access to the cycle for which it applies. Exemption requests must be submitted with their application submittal.

Q. PLEASE EXPLAIN THE REPLACEMENT FACILITY EXEMPTION.

A. Under the Tariff, Replacement Generating Facility requests generally are processed outside the interconnection queue. One exception to this process is when a Replacement Generating Facility requires Interconnection Service (in MW) in excess of that of the Existing Generating Facility that is being replaced. In such instances, the Replacement Generating Facility is allowed to generate up to the existing Interconnection Service of the Existing Generating Facility. However, an Interconnection Request associated with the excess MW value must proceed through the regular DPP cycle procedures. The proposed

exemption is for such excess capacity requests. Such requests are highly valuable to the MISO Transmission System because they are certain: the Replacement Generating Facility was already approved through the replacement process and exists under an executed replacement GIA.

Q. PLEASE EXPLAIN THE ERIS TO NRIS CONVERSION EXEMPTION.

A. The Tariff allows Interconnection Customers to convert their ERIS to NRIS, which is a higher level of Interconnection Service. The conversion requires submission of an Interconnection Request and proceeding through the queue. MISO proposes to exempt such "NRIS conversion" Interconnection Requests from the cap. The rationale is similar to that for the Replacement Generating Facility exemption discussed above. The Interconnection Request seeking conversion already has an executed GIA and as such, are highly valuable to the MISO Transmission System.

Q. PLEASE EXPLAIN THE PGIA EXEMPTION.

A. MISO's Tariff currently includes a process that allows its Interconnection Customers to enter into a PGIA before the end of the DPP cycle. The PGIA allows limited operation, based upon the results of available studies. This option allows an Interconnection Customer with a ready project to connect to the MISO Transmission System and inject power into the grid before the completion of all studies. The potential downside of the PGIA is that Interconnection Customers assume the risk of interconnecting prior to the completion of Network Upgrades being identified through the DPP process. Because Interconnection Customers with a requested PGIA have assumed additional risks and commit to proceeding through the DPP cycle regardless of the potential costs of Network Upgrades, MISO views these types of Interconnection Requests are as certain as existing

generation—so long as the ability to revert is limited. Unlike MISO's current PGIA process, which allows reversion from provisional to non-provisional status, Interconnection Customers that claim this exemption will forfeit its ability to revert with no consequences. Any Interconnection Customer that elects to proceed under the PGIA exemption and reverts back to non-provisional status will lose all monies and will forfeit its queue position. This exemption is available to any Interconnection Customer willing to assume PGIA risks, thus allowing an exception for Interconnection Customers who are willing to make commitments that a reasonable developer would not undertake for an uncertain project.

Q. PLEASE EXPLAIN WHY THE RERRA EXEMPTION WAS REMOVED FROM THIS UPDATED CAP FILING.

A. In early 2024, MISO and its stakeholders embarked on a joint effort to address the challenges introduced with the RERRA exemption. MISO engaged in discussions with stakeholders to identify the challenges associated with the implementation of the RERRA exemption for the cap. MISO identified several concerns with the original RERRA exemption process. First, MISO was concerned with how to limit the size of RERRA exemptions. The RERRA exemptions, unlike the included exemptions, posed a particular risk to diminishing the value of the cap. Second, multiple stakeholders brought forth comments regarding the standardization of format and processing of the RERRA exemptions. Third. MISO further recognized this as a more distinct queue issue that should be addressed in a separate process. There is a fundamental necessity for a short-term generator interconnector product to handle direct urgent resource adequacy needs for the states within the MISO system. Due to these challenges, MISO removed the RERRA

exemption from the current filing. However, the importance of RERRAs to the MISO Transmission System is not lost on MISO. To better respond to the unique needs of RERRAs, MISO will work with stakeholders on a separate, concentrated effort to address the unique resource adequacy needs of a RERRA. MISO has committed to working on addressing the needs of RERRA entities through a new ERAS process that is being developed with stakeholders now and will more comprehensively address the approval process of new generation needed to address resource adequacy.

VI. STAKEHOLDER PROCESS

Q. PLEASE DESCRIBE THE STAKEHOLDER PROCESS USED TO DEVELOP THIS PROPOSAL.

A. MISO engaged in an extensive stakeholder process throughout the development of its updated queue cap proposal. MISO obtained feedback through the PAC and the IPWG, conducted dozens of calls with stakeholders across the MISO sectors, and receiving multiple rounds of formal and informal written feedback. During the stakeholder process, MISO considered the advantages and disadvantages of multiple approaches for addressing the identified challenges and risks, collaborating with stakeholders on identifying areas where flexibility could be increased. MISO revised its initial proposal considerably, incorporating the input received.

The key milestones of the stakeholder process were as follows:

- January 30, 2024: MISO provided an update to the IPWG regarding FERC's response on MISO's GIP Improvements and Cap filings, along with next steps.
- July 23, 2024: MISO presented several updates to the cap proposal to address FERC concerns with the original filing at the IPWG

- September 3, 2024: MISO provided refined proposal and responded to feedback at the IPWG.
- September 30, 2024: MISO held a special IPWG workshop to review the current proposal and answer stakeholder questions
- October 16, 2024: MISO presented a final package of reforms at the PAC. MISO also introduced its Expedited Resource Adequacy Study proposal.[9]

Q. WHAT WAS MISO'S RESPONSE TO CONCERNS AND RECOMMENDATIONS FROM STAKEHOLDERS?

A. Stakeholders asked MISO to justify a rationale for the 50% limitation, with some expressing concern that this cap would "arbitrarily" reduce the number of projects that can compete. MISO understands these concerns but notes that the rationale for selecting 50% is to ensure a balance of supply to demand while also addressing the queue administration difficulties MISO faces due to the volume of Interconnection Requests. Without limiting the amount of Interconnection Requests, the interconnection queue will continue to grow at an unsustainable rate, slowing study processes and making results less accurate. MISO supports many of the objectives of the alternative Savion VPE Proposal and is committed to working with stakeholders to incorporate elements of that proposal to meet those objectives.

Q. IS MISO STILL CONINUING TO IMPROVE QUEUE COORDINATION WITH INTERCONNECTION CUSTOMERS AND TRANSMISSION OWNERS?

A. Yes. In addition to the proposed Tariff changes, MISO has multiple efforts underway to enhance the queue experience. These transparent initiatives will facilitate enhanced

9 ERAS Workshop Citation

Interconnection Customer workflow throughout Interconnection Request lifecycle. MISO is coordinating the development of these enhancements through the stakeholder process.

VII. CONCLUSION

Q. IN YOUR OPINION, ARE MISO'S FILINGS JUST AND REASONABLE?

A. Yes. This updated cap Filing address certain specific needs that MISO, the Commission and the stakeholder process identified. To ensure that MISO is on the right track to resolving its interconnection backlog, MISO requests that the Commission approve this updated proposal. The proposed new Tariff revisions address the Commissions earlier concerns and will significantly enhance the GIP by reducing queue delays and by improving the precision and timeliness of Interconnection Studies and will enable MISO to take the necessary steps to manage the size of individual cluster studies performed during the interconnection queue process.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Affidavit of Andrew Witmeier

COUNTY OF HAMILTON)

)

STATE OF INDIANA)

Andrew Witmeier, being duly sworn, deposes and states that he prepared the Prepared Direct Testimony of Andrew Witmeier, and the statements contained therein are true and correct to the best of his knowledge and belief.

Andrew Witmeier

SUBSCRIBED AND SWORN BEFORE ME, this 7th day of November, 2024.

Jennifer L. Miller
Notary Public, State of Indiana
Boone County
Commission Number 697079
My Commission Expires
February 22, 2025

EXHIBIT 1
TO
PREPARED DIRECT TESTIMONY OF
ANDREW WITMEIER

Prepared for:
Midcontinent Independent System Operator
720 City Center Drive
Carmel, IN 46032

MISO Generator Interconnection Queue: M2, M3, and M4 Security Deposits and Return Procedures

Evaluation and Suggested Adjustments

Prepared by:
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Date: September 27, 2023

CONFIDENTIAL MATERIAL

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1. BACKGROUND

The Midcontinent Independent System Operator (MISO) generator interconnection queue has experienced significant growth, leading to a substantial backlog of projects that is negatively impacting MISO stakeholders and interconnection customers. Recognizing this challenge, MISO has undertaken efforts to improve the efficiency of the interconnection queue process and reduce the backlog.

In pursuit of these objectives, MISO has enlisted the expertise of Charles River Associates (CRA) to provide an independent review of current rules for entry to and exit from the interconnection queue. Within the review, we evaluate the security deposits required within the MISO Definitive Planning study process, with a specific focus on the M2, M3, and M4 deposit amounts. The analysis conducted by CRA has relied upon data from the 2017-2022 study cycles, which forms the basis for the charts and recommendations presented in this report.

CRA's historical analysis has concentrated on the volume of interconnection requests, the magnitude of network upgrade costs assessed at different stages of the queue process, and withdrawal rates. These analyses have provided insights into how deposit amounts, policies, and the overall study process can be restructured to enhance the efficiency of the interconnection queue.

2. STATE OF THE QUEUE

A prevailing trend observed with respect to the interconnection queue studies published in recent years[1] is the consistent rise in queue sizes, accompanied by prolonged wait times and elevated withdrawal rates.

2.1. QUEUE SIZE

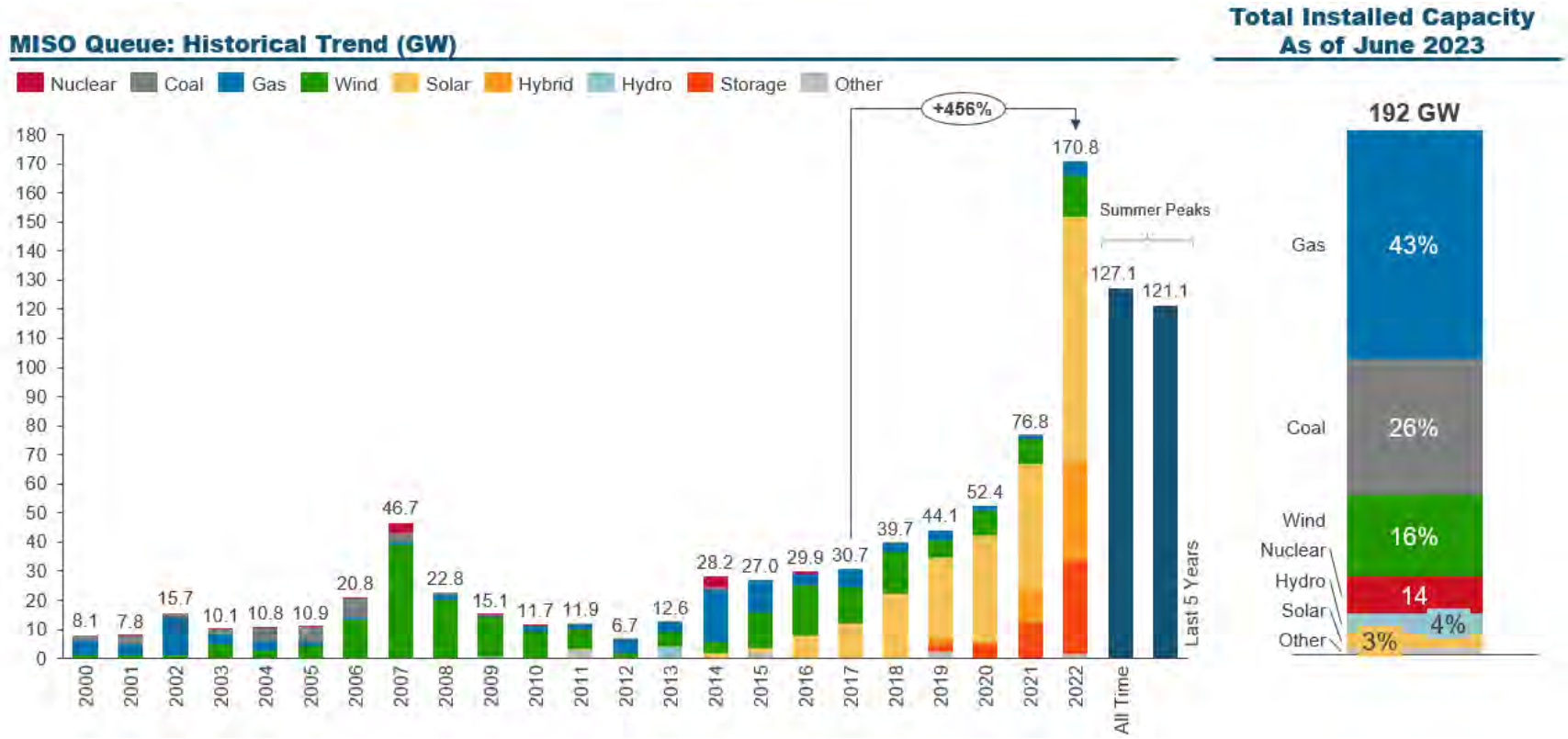
Figure 1 illustrates a concerning trend in the MISO queue. For years, the queue remained relatively stable but has inflated significantly in recent years to increasingly unmanageable levels. Comparing the 2022 queue size to the 2017 cycle, the queue has grown by 4.5 times. Moreover, the 2022 queue size, which stands at 170.8 GW, surpasses the all-time MISO summer peak demand of 127.1 GW and approaches the total MISO installed capacity of 192 GW.

The analysis of the 2022 interconnection queue, as presented in Figure 1, examines the costs associated with bringing all submitted capacity online as installed capacity. Results will likely show that significant costs are required, in the form of network upgrade and affected system costs, to bring all submitted capacity online. This data has been examined to give context to the proposed reforms outlined in this report and to help quantify the suggested magnitudes of deposits required and deposits at risk of forfeiture.

[1] For example, “Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection” published by Berkeley Lab https://emp.lbl.gov/queues

As a practical matter, a significant portion of the queued generation will not ultimately be placed in service and much of the study effort will, arguably, be wasted.

Figure 1. MISO Queue: Historical Trend (GW)



Source: MISO

2.2. QUEUE PHASES, MILESTONES, AND TIMING [2]

The MISO interconnection queue study process is structured into distinct phases and incorporates milestone payments. In the pre-queue phase, interconnection customers (ICs) submit interconnection requests and MISO carries out essential preliminary tasks before commencing a formal study. These tasks include a set of initial screenings and a scoping meeting. A completed application includes an M2 milestone payment of $4,000 per MW studied.

The MISO Definitive Planning Phase (DPP) follows the pre-queue phase. During this phase, detailed studies and planning activities are conducted to assess the feasibility and impact of the proposed project on the MISO transmission system. The DPP consists of three phases: DPP Phase 1 (DPP 1), DPP Phase 2 (DPP 2), and DPP Phase 3 (DPP 3).

In the initial phase of the Definitive Planning Phase (DPP 1), the interconnection customer receives a comprehensive preliminary analysis of their request's impact on the reliability of the transmission system. During this phase, MISO conducts the initial Model Building and Review, followed by the preliminary System Impact Study (SIS). After completing the analysis, interconnection customers reach Decision Point I, where they have two options: (1) withdraw their request and potentially be subject to harm calculations (i.e., calculations to determine whether withdrawal shifted cost from the withdrawn project to other projects), with a potential to lose up to 50% of the M2 deposit, or (2) choose to proceed further in the queue process by paying an additional security deposit (M3). The M3 security deposit equals 10 percent of the network upgrade cost, as assessed in DPP 1, minus the M2 deposit.

DPP 2 is designed to provide the interconnection customer with a revised and more detailed analysis of the interconnection project's impact on the reliability of the transmission system after incorporating updated generation assumptions resulting from the withdrawal of interconnection requests during DPP 1. Once the revised SIS and affected system analysis are completed, inclusive of estimated upgrade costs, the interconnection customer enters Decision Point 2. Here, if the interconnection customer decides to withdraw, 100% of the M2 deposit becomes at risk (subject to harm calculations), and 100% of M3 is returned. If the project meets penalty-free withdrawal criteria,[3] 100% of the M2 deposit is returned. If the interconnection customer decides to continue in the queue, they are required to submit an M4 deposit. The M4 deposit equals 20% of the network upgrade cost calculated in DPP 2, minus the M3 and M2 deposits.

DPP Phase 3 is designed to provide ICs with a final, detailed analysis of their interconnection project's impact on the reliability of the transmission system after incorporating updated generation assumptions due to the withdrawals of interconnection requests during Decision Point 2. All milestone deposits (M2, M3, and M4) become at risk and subject to harm calculations upon entry into Phase 3. However, all three deposits may be returned in full upon withdrawal in DPP 3 if the project meets penalty-free withdrawal criteria.

[2] Information in this section is based on MISO's Generation Interconnection Business Practices Manual PM-015-r25

[3] Section 7.6.2.4 Withdrawal and refund due to increase in network upgrade costs of Generator Interconnection Procedures

The Generation Interconnection Agreement (GIA) Execution Phase follows DPP 3. For more detail, see MISO's Generator Interconnection Procedures, and Generation Interconnection Business Practices Manual.

We find that in our sample, the average length of the pre-kick off phase is 305 days and the average length of the DPP1 is 298 days, see Figure 2 below.

Figure 2. Days spent in each queue cycle (2017-2022)

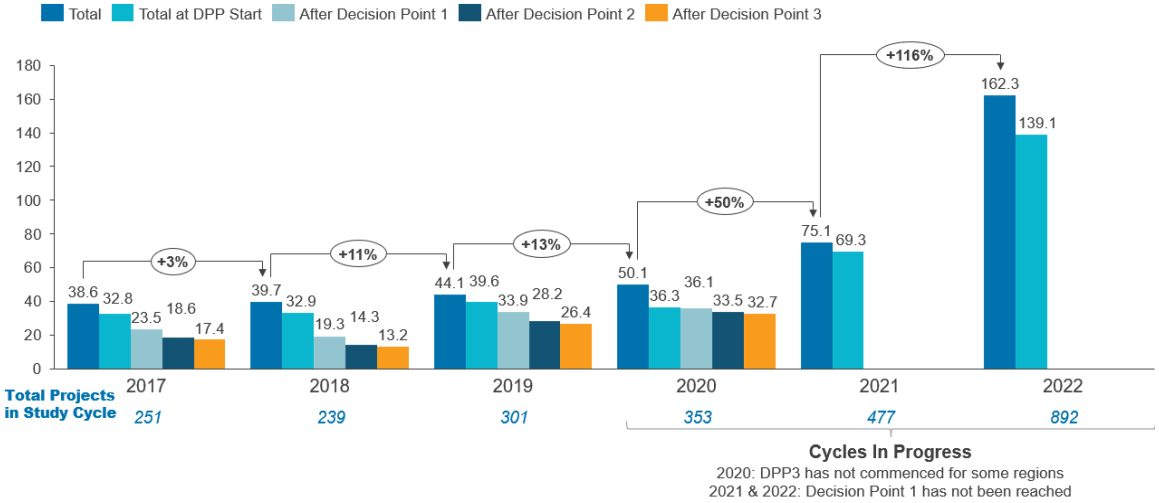
Queue Phase	Average # days in phase
Pre-Kick-Off	305
DPP 1	298
DPP 2	200
DPP 3	187
GIA Execution	142

Source: MISO

2.3. WITHDRAWALS

Figure 3 further illustrates the year-over-year percentage increase in the size of the interconnection queue along with the dynamics of withdrawals. The queue size has experienced significant growth, with the steepest increase occurring between the 2021 and 2022 cycles, where the queue expanded by 116%. The withdrawals are significant and occur at every stage.

Figure 3. MISO Queue Withdrawals by Cycle (GW)



Source: MISO. Note: This figure does not include withdrawals without a specified date.

Table 1. MISO Queue Withdrawals by Cycle, percentages based on MW withdrawn

Status	Withdrawal Phase	DPP-2017-AUG	DPP-2017-FEB	DPP-2018-APR	DPP-2019-Cycle	DPP-2020-Cycle	DPP-2021-Cycle	DPP-2022-Cycle
Active		2%	0%	0%	13%	53%	88%	86%
Done		35%	26%	32%	44%	6%	0%	0%
Withdrawn								
	Pre Kick-off	19%	1%	17%	10%	28%	8%	14%
	Decision Point 1 (DPP 1)	22%	34%	34%	13%	0%	2%	0%
	Decision Point 2 (DPP 2)	11%	17%	13%	13%	5%	0%	0%
	During DPP Phase 3	1%	11%	3%	4%	2%	0%	0%
	During GIA Execution Phase	8%	0%	0%	0%	1%	0%	0%
	Post GIA	2%	11%	1%	0%	0%	0%	0%
	Withdrawn (Other)	0%	0%	0%	2%	6%	2%	0%
Withdrawn Total		63%	74%	68%	43%	41%	12%	14%

Source: MISO.

Table 1 provides an overview of the percentage of total MW in the queue that has been withdrawn at various stages, including Active and Done[4] . Note that as of now, the 2019-2022 queue cycles remain active. Looking at the fully completed cycles in our sample (2017-2018

[4] Done means the project has completed the interconnection queue process.

cycles), nearly 70% of the total generation capacity that entered these cycles was eventually withdrawn. We observe that a considerable percentage of capacity is withdrawn during the Pre-Kick-off phase. The 2022 Cycle for example, which has not yet reached the DPP Phase, has already had 14% of the initially entered capacity withdrawn. This raises concerns about whether some projects are being entered into the queue speculatively without undergoing proper due diligence. Most of the withdrawn projects exit either before the DPP Start or at Decision Point 1, which highlights the need to incentivize more careful project assessment before entry into the queue.

Next, we examine the withdrawal dynamics based on the relative portion of the queue that each participant holds. The company size is determined by considering the total MW of projects within our sample. Table 2 illustrates the overall share of projects and the withdrawal pattern for the top developers in MISO territory.

According to the data in Table 2, the top 3 companies (as defined by requests to enter into the queue) collectively accounted for 30% of the capacity entered into the 2017 - 2022 interconnection queues. Of all applications submitted by these top 3 companies, 72% were eventually withdrawn. As we expand our analysis to include more companies, the overall percentage of withdrawn applications decreases. In comparison, when considering all companies in the sample, the withdrawal rate was 53%. This observation may imply a greater likelihood of speculative entry among the most active companies.

Table 2. MISO Queue Withdrawals by Top Interconnection Customers

	Withdrawn MW 2017 – 2020 Cycles		Point of Withdrawal			
	MW submitted into queue as % of all projects	Out of submitted, % withdrawn	% Withdrawn before DPP Start	% Withdrawn at DPP1	% Withdrawn at DPP2	% Withdrawn Phase 3 and after
Top 3 Companies	30%	72%	32.5%	37.8%	22.6%	5.5%
Top 5 Companies	34%	69%	36.3%	34.8%	21.6%	5.9%
Top 10 Companies	40%	68%	38.4%	32.1%	20.9%	7.4%
Top 15 Companies	43%	67%	37.0%	33.4%	20.2%	6.9%
Top 20 Companies	46%	66%	38.0%	33.2%	19.3%	7.1%
Top 25 Companies	49%	67%	36.4%	32.8%	19.3%	8.6%
All Companies	**100%**	**53%**	**33.6%**	**31.4%**	**19.7%**	**11.0%**

Source: MISO. Note: figures by row may not sum to 100% due to missing withdrawal dates for some projects.

When we consider the timing of withdrawals, the top companies' withdrawal patterns differ from the broader pool of companies in the sample. The top developers are more likely to withdraw in the initial stages of the process and less likely to withdraw in Phase 3 or beyond. This finding suggests that top companies might have greater resources enabling follow-through and

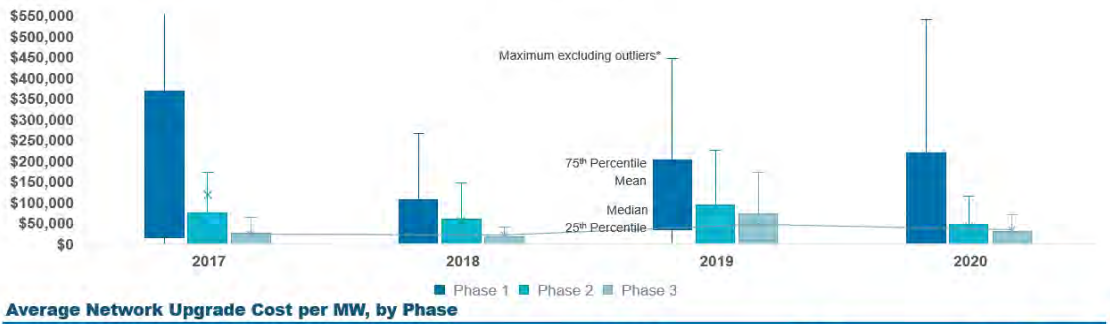
commitment, which explains the lower withdrawal rates at later phases as compared to other companies in the sample.

2.4. NETWORK UPGRADE COSTS

In this section, we analyze the network upgrade costs per MW. As previously discussed in Section 2.2, the network upgrade costs are initially calculated in DPP 1, followed by DPP 2, and ultimately finalized in DPP 3. For a comprehensive overview, Figure 4 illustrates the network upgrade costs for the cycles spanning from 2017 to 2020, allowing for a comparison of average costs across the three DPP phases.

The average network upgrade costs in DPP 1 are notably higher compared to those in DPP 2 and DPP 3. This outcome is not surprising, considering the larger size of the initial queue. As projects progress through the phases, many drop out, leading to a more manageable number of projects being analyzed and, consequently, more realistic network upgrade costs. Additionally, the projects with the highest network upgrade costs are expected to drop out first.

Figure 4. Network Upgrade Cost per MW, by DPP Phase[5]



Average Network Upgrade Cost per MW, by Phase

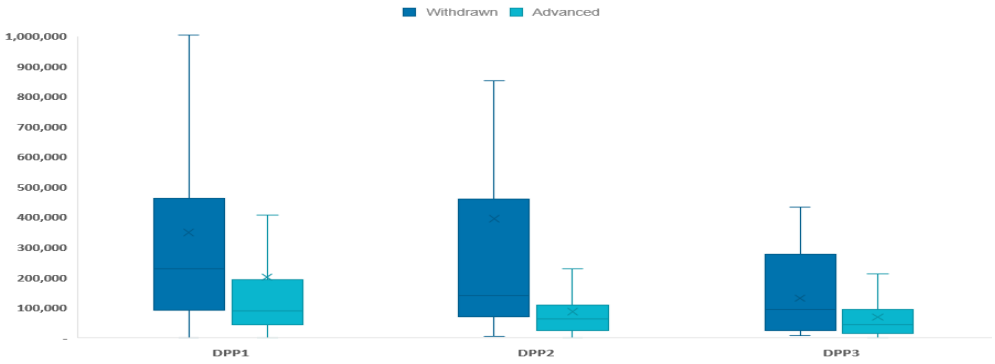
	2017	2018	2019	2020	Average
Phase 1	$341,916	$101,703	$170,781	$297,694	$232,051
Phase 2	$216,525	$100,492	$122,008	$112,098	$138,353
Phase 3	$53,518	$56,483	$82,037	$94,279	$72,514

Source: MISO.

[5] A box plot consists of a rectangular "box" that represents the interquartile range (IQR) of the data, (25th to 75Th percentile), and the "whiskers" show the range of the data. Any data points beyond the whiskers are considered outliers and are not shown on this chart.

We observe that the sample mean (marked as 'x') consistently exceeds the median (denoted by a line). This suggests that most of the projects within each plotted distribution have network upgrade costs lower than the average.

Figure 5. Network Upgrade Cost per MW, by Phase and Status



Average Network Upgrade Cost per MW, by Phase and Status

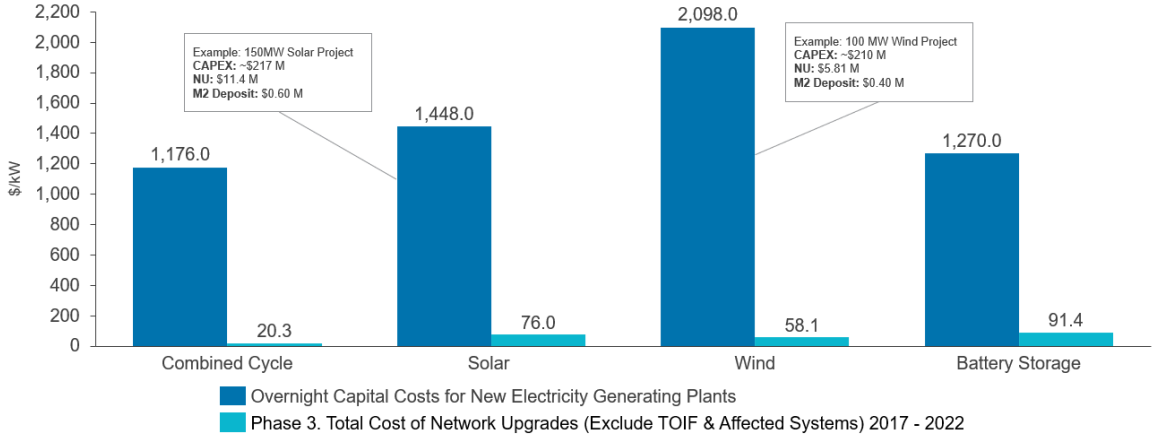
	DPP1	DPP2	DPP3
Withdrawn	$349,601	$395,560	$132,849
Advanced	$201,878	$87,747	$70,059

Source: MISO.

Figure 5 presents the aggregate data for the 2017 – 2020 cycles. It illustrates the distinct cost distributions of network upgrades for projects that either proceeded to the subsequent DPP stage or were withdrawn at each respective DPP stage. At Decision Point 1, the average network upgrade cost per MW for a withdrawn project was $349,601, and projects that advanced to the next stage had an average network upgrade cost of $201,878. As anticipated, the projects that were advanced tend to, on average, have lower costs compared to those that were withdrawn.

The average network upgrade cost for projects that advanced beyond DPP 1 is notably higher than those advanced beyond DPP 2. This suggests that developers have an understanding that the network upgrade costs are likely to decrease in subsequent phases.

Figure 6. Network Upgrade Cost per MW vs. CapEx



Source: MISO (2017-2022 Cycles), EIA AEO (March 2023) Overnight Capital Costs for New Electricity Generating Plants

Figure 6 illustrates the comparison between the capital costs needed to construct a new generation facility and the average network upgrade costs that the same facility is anticipated to incur for securing interconnection in MISO. The network upgrade costs constitute only a fraction of the overall budget that developers are required to allocate.

This consideration plays a role when discussing incentives to deter speculative entry into the interconnection queue. The accepted economic deterrents for unwanted behavior are penalties. To be effective, penalties should be assessed within the context of overall costs and budgets.

3. RECOMMENDATIONS

This section presents our recommendations for MISO queue policies, aiming to achieve the dual goals of reducing the size of the interconnection queue and decreasing the withdrawal rate. Once these challenges are successfully addressed, study times will decrease, leading to enhanced efficiency within the MISO interconnection queue. This improvement will enable MISO to process more projects more quickly than the current situation allows and should result in customers receiving more dependable information with which to make business decisions regarding their projects.

3.1. DEFINITION OF HARM

The interconnection queue within MISO has reached a point where it has become unmanageable at entry, and modeling upgrade costs in the early phases has become unrealistic. Additionally, the frequent dropouts within the interconnection queue create significant uncertainty, making the results of studies unreliable and subject to significant change over the course of the study process. This constant fluctuation requires continual reevaluation, adding complexity to the process. We observed that interconnection requests are withdrawn at every stage, leading to changes in results and even more withdrawals.

Two behavioral aspects behind the problems identified above are (1) speculative entry and (2) frequent withdrawals. The two aspects are intertwined as projects that enter the queue without due diligence regarding readiness and feasibility are more likely to be withdrawn.

Effective preventive measures should be implemented to discourage these harmful behaviors. Creating and enforcing these measures establishes a more responsible environment, minimizing harm. To achieve this, harmful behavior must be clearly defined. Once appropriately defined, it becomes the basis for levying penalties where harmful behavior is proven to exist.

Withdrawals are unlikely to be penalized under the present definition of harm, which is narrowly focused on cost increases to remaining projects due to required Network Upgrades following a project's withdrawal. This definition accounts for situations where shares of required transmission upgrades are allocated to remaining projects after a re-study analysis. However, it may also result in less expensive required transmission upgrades and lower allocated shares, reflecting the stepped nature of upgrade costs as incremental generation capacity is accommodated. Such outcomes do not mean that the remaining projects are unharmed by the withdrawal. On the contrary, they suffer from the additional time required for necessary re-studies and the uncertainty engendered by the constantly changing queue.

Interdependencies among projects and shared information mean that withdrawals inevitably impact other projects through delays and increased uncertainty; these two impacts should be recognized as harmful:

> Delays: The study process is delayed when projects withdraw, and previously identified upgrades may no longer be applicable. This leads to more time required for analysis.
>
> Uncertainty: Projects in the queue rely on network upgrade estimates for crucial business decisions, and these decisions are undermined when projects are withdrawn.

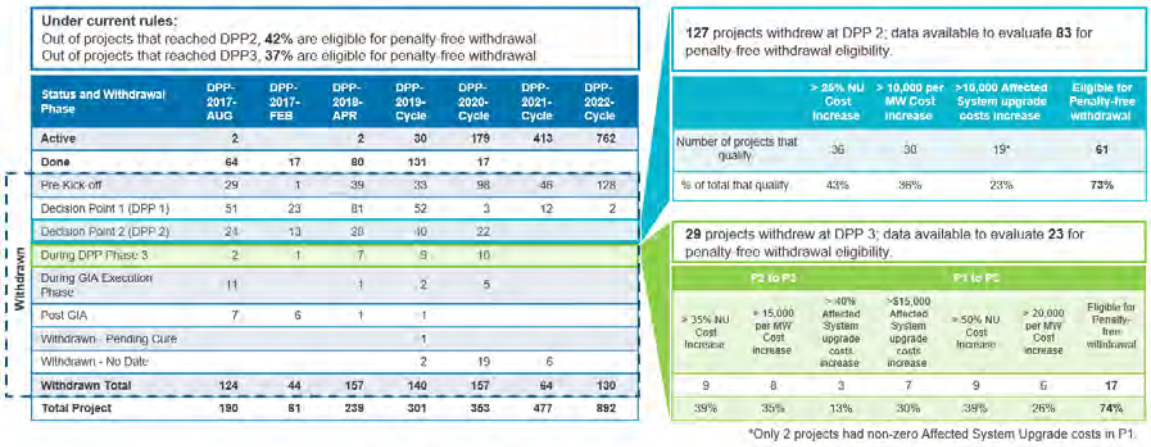
Regardless of why a project is withdrawn from the interconnection queue, such withdrawal invariably inflicts some harm on remaining projects. This harm might be quantifiable in monetary terms but is often intangible and can only be described qualitatively.

Besides the measurable harm of increased upgrade costs, the delays and uncertainty inherent in the process argue for a harm penalty. This penalty, even when the harm isn't directly measurable, should escalate with each stage of the process to encourage early decision-making regarding non-viable projects. The presence of such a penalty recognizes that harm extends beyond mere dollars and cents, encompassing broader impacts on the queue's efficiency and reliability.

3.2. PENALTY FREE WITHDRAWAL ADJUSTMENT

Penalty-free withdrawal should be eligible only for projects facing a significant increase in total costs. Current MISO rules that allow for penalty-free withdrawal are outlined in Section 7.6.2 Refunds of Definitive Planning Phase Milestones (M2, M3, M4) of the Generator Interconnection Procedures (GIP). Figure 7 below summarizes our analysis of the penalty-free withdrawal rules.

Figure 7. Penalty-free withdrawal rules application



Under current rules:
Out of projects that reached DPP2, **42%** are eligible for penalty free withdrawal
Out of projects that reached DPP3, **37%** are eligible for penalty free withdrawal

Status and Withdrawal Phase	DPP-2017-AUG	DPP-2017-FEB	DPP-2018-APR	DPP-2019-Cycle	DPP-2020-Cycle	DPP-2021-Cycle	DPP-2022-Cycle
Active	2		2	30	179	413	762
Done	64	17	80	131	17		
Pre Kick-off	29	1	39	33	98	46	128
Decision Point 1 (DPP 1)	51	23	81	52	3	12	2
Decision Point 2 (DPP 2)	24	13	28	10	22		
During DPP Phase 3	2	1	7	9	10		
During GIA Execution Phase	11		1	2	5		
Post GIA	7	6	1	1			
Withdrawn - Pending Cure				1			
Withdrawn - No Date				2	19	6	
Withdrawn Total	124	44	157	140	157	64	130
Total Project	190	61	239	301	363	477	892

Withdrawn

127 projects withdrew at DPP 2; data available to evaluate **83** for penalty-free withdrawal eligibility.

	> 35% NU Cost increase	> 10,000 per MW Cost increase	>10,000 Affected System upgrade costs increase	Eligible for Penalty-free withdrawal
Number of projects that qualify	36	30	19*	61
% of total that qualify	43%	36%	23%	73%

29 projects withdrew at DPP 3; data available to evaluate **23** for penalty-free withdrawal eligibility.

P2 to P3				P1 to P2		
> 35% NU Cost increase	> 15,000 per MW Cost increase	> 40% Affected System upgrade costs increase	>$15,000 Affected System upgrade costs increase	> 50% NU Cost increase	> 20,000 per MW Cost increase	Eligible for Penalty-free withdrawal
9	8	3	7	9	6	17
39%	35%	13%	30%	39%	26%	74%

*Only 2 projects had non-zero Affected System Upgrade costs in P1.

Source: MISO

The penalty-free withdrawal procedure is based on a comparison between the previously estimated network upgrade cost within the same cycle and the new estimates. As such, this procedure is only applicable at Decision Point 2 and when the DPP3 cost estimates become available.

Current rules allow for a broad set of circumstances to qualify. For example, projects that experience a significant decrease in network upgrade costs may still qualify if affected systems costs increase. This is one of the key reasons why penalty-free withdrawals apply to a large number of projects in the queue. For example, 42% of all projects that reached DPP2 are eligible for penalty-free withdrawal, and 37% of all projects that received network upgrade costs in phase 3 are eligible for penalty-free withdrawal in that phase.

Simple and efficient rules ensure that only projects facing significant increases in overall costs qualify for penalty-free withdrawal. We suggest streamlining the rules and applying only a percentage increase in combined network upgrade and affected systems costs from DPP1 to DPP2 or DPP2 to DPP3. That is, streamline rules to allow penalty-free withdrawal if:

Combined NU + AS cost increased by 50% from P1 and P2 (1)

Combined NU + AS cost increased by 35% from P2 and P3 (2)

The suggested thresholds of 50% and 35% are selected using data in Table 3 below. First column in Table 3 is the threshold, second shows the % of projects that reached DPP2 that would be eligible for penalty free withdrawal under (1) above, and the third column shows the % of projects that reached DPP3 eligible for withdrawal penalty-free withdrawal under (2) above.

At the suggested threshold of 50% cost increase from P1 to P2, 30% of all projects that reached DPP2 would be eligible for penalty-free withdrawal. At the suggested threshold of 35% cost increase from P2 to P3, 20% of all projects that reached DPP3 would be eligible for penalty-free withdrawal.

Table 3. Sensitivity of Withdrawal Eligibility to NU + AS Threshold

Combined NU + AS % Increase Threshold	P2 to P1: % of Projects that Reached DPP2 Eligible for Withdrawal	P3 to P2: % of Projects that Reached DPP3 Eligible for Withdrawal
10%	43%	27%
20%	37%	22%
25%	36%	21%
30%	**34%**	20%
35%	33%	20%
40%	31%	**18%**
45%	31%	16%
50%	30%	15%
55%	29%	14%
60%	29%	13%
65%	27%	13%

Source: MISO

3.3. M2, M3 AND M4 ADJUSTMENTS

We recommend that MISO adjusts M2, M3, and M4 deposits to better reflect potential harm caused by a withdrawal at each study phase.

In The M2 deposit should be more representative of the final NU payment and significant enough to discourage speculative behavior. To aid our analysis of the appropriate deposit we consider average per MW costs in each phase of DPP cycle. We consider a range of 15% to 25% of the average NU cost in Phase 3 to determine a reasonable value range for the M2 deposit amount.

Table 4. Network Upgrade Costs[6]

Study Cycle	Average of NU Cost per MW, Phase 1	Average of NU Cost per MW, Phase 2	Average of NU Cost per MW, Phase 3	15% of NU Cost in Phase 3	20% of the NU Cost in Phase 3	25% of NU Cost in Phase 3
DPP-2017-AUG	$177,999	$118,107	$53,583	$8,038	$10,717	$13,396
DPP-2017-FEB	$840,358	$521,006	$53,247	$7,987	$10,649	$13,312
DPP-2018-APR	$101,703	$100,492	$56,483	$8,472	$11,297	$14,121
DPP-2019-Cycle	$170,781	$122,008	$82,037	$12,306	$16,407	$20,509
DPP-2020-Cycle	$297,694	$112,098	$94,279	$14,142	$18,856	$23,570
Total In-Sample Average	**$232,051**	**$138,353**	**$72,514**	**$10,877**	**$14,503**	**$18,129**
Total in-Sample Median	**$80,624**	**$70,690**	**$48,420**	**$7,263**	**$9,684**	**$12,105**

Source: MISO

We recommend an increase of the M2 amount from $4,000 / MW to a value in the range of $10,000 to $14,000 / MW.

Deposits should increase at each stage, reflecting harm that occurs with withdrawal at later stages in the study process. Additionally, we suggest that M3 and M4 deposits should never be negative. Negative or zero deposits are not representative of harm that occurs should a project withdraw. We suggest adjusting M3 and M4 formulas to:

$$M3 = \text{Max of } \$1{,}000 \text{ and } ((10\% * NU) - M2)$$

$$M4 = \text{Max of } \$1{,}000 \text{ and } ((20\% * NU) - M3 - M2)$$

We believe that this deposit structure more accurately aligns with the network upgrade costs that developers are likely to incur.

3.4. Fixed Penalty Schedule

To mitigate the issues of an unwieldy queue size and frequent withdrawals, it is essential to implement penalties for detrimental practices. As previously discussed, both entering the queue without adequate due diligence and exiting the queue by interconnection customers contribute to an unmanageable queue size and create significant uncertainty.

Penalties are a proven economic lever for curbing undesirable behavior. For such penalties to be effective, they must be both substantial and consistently applied when unwanted actions occur.

Requiring a deposit alone is not a sufficient deterrent unless it is integrated with a comprehensive penalty structure. We propose implementing a fixed penalty schedule in conjunction with the current penalties to address this. Specifically, the current total amounts at risk from the DPP1 and beyond will remain unchanged. However, a predetermined percentage of the M2 deposit will be forfeited at withdrawal, regardless of the specific harm calculations. This percentage should

[6] Similar table based on median values is included in the Appendix

escalate with each successive phase of the DPP. We recommend that this penalty be applied to every withdrawal, extending even to those that occur before the commencement of the DPP.

Table 5 illustrates the suggested penalty schedule with an example.

Table 5. Current and Potential Penalties by DPP Cycle

Withdrawal Time/ Stage of the Cycle	Current Penalties: at risk subject to harm calculations	Suggested Penalty Schedule: Example		
		Fixed Penalty Schedule	*Harm Calculation*	*Penalty-Free withdrawal*
Before DPP Start	No penalty	10% of M2 Deposit	Doesn't apply	Doesn't apply
Decision Point 1	50% of M2 at risk	25% of M2 Deposit	Applies	Doesn't apply
Decision Point 2	100% of M2 at risk	50% of M2 Deposit	Applies	Applies
During Phase 3	M2, M3, and M4 at risk	75% of M2 Deposit	Applies	Applies
GIA Execution Phase and beyond	M2, M3, and M4 at risk	100% of M2 Deposit	Applies	Doesn't apply

Source: MISO

We suggest distributing the collected penalties pro-rata to completed projects of the same cycle. This provides additional support for projects that go through the process and additional incentive for interconnection customers to complete projects.

3.5. QUEUE CAP PER CYCLE

Robust demand for generation interconnection has caused the MISO queue to grow to an unmanageable size, with interconnection requests exceeding what MISO can process in a single cycle, contributing to a substantial backlog.

To mitigate the negative impact of excessive requests on participants and the overall study process, establishing a queue cap might be a solution. The implementation of a queue cap not only limits these detrimental effects but also strengthens the case for withdrawal penalties at every stage, including pre-kick-off.

The excessive interconnection requests compromise other study cycle participants and the overall integrity of the study process. As previously shown, these excessive requests can artificially inflate the magnitude of network upgrade costs in the early stages of the study cycle, leading to escalating financial and manpower burdens on MISO and other stakeholders as the queue size surpasses reasonable limits. Moreover, dissatisfaction with the process could fuel more speculative requests, and projects forced to drop out may swell the number of requests seen in subsequent study cycles.

MISO should determine the level of the queue cap along with its application across study regions, cycles, and possibly entities. The cap should be designed considering certain criteria for MISO overall and by region. For example, the following could be considered:

- Peak load and forecasted peak load.
- Installed capacity, guaranteed additions, and expected retirements.
- Reliability and resource adequacy.

All applications in excess of the cycle queue cap should be entered into the next cycle.

To give a tangible example, the queue cap per cycle could be set as a percentage of the forecasted peak load and/or installed capacity.

3.6. PER DEVELOPER CAP

Implementing a per-developer cap can be an approach to ensuring fairness within the interconnection queue, though it may present challenges in execution. To prevent a single developer from having disproportionate control or excessively entering multiple projects, it is advisable to consider specific safeguards when putting an overall queue cap in place.

These safeguards should be designed to maintain a balanced playing field among developers. It's important to recognize that no specific threshold is universally accepted to spark antitrust concerns; rather, this depends on a variety of factors, including market concentration, the potential for market manipulation, barriers to entry, and the possibility of harm to competition.

If an overall queue cap is put in place, we recommend considering a per-developer cap as well, set at a level between 5% and 15% of the overall queue cap per cycle. The implementation of a per-developer cap would necessitate a robust administrative process, with certain key elements to be included. These could encompass:

- **Authentication**: Define the entity or organization that is subject to the cap. Clear procedures should be established to ensure that all branches or subsidiaries of the same organization are included under the same cap.
- **Monitoring and Reporting**: Establish a system to track the project entries of each developer.
- **Verification**: Develop processes to validate the reported information provided by developers.
- **Transfers**: Ensure that transfers do not result in cap violations.
- **Penalties**: Define penalties for developers who exceed the prescribed limits.
- **Appeals and Dispute Resolution**: Establish a process for developers to appeal decisions related to cap enforcement.
- **Regular Review and Adjustment**: Conduct regular reviews of the cap's effectiveness and consider adjustments if necessary.

4. SUMMARY

CRA’s analysis supports the argument that reform to generator interconnection queue rules for queue entry and exit could alleviate interconnection constraints. A key step to reform is an

adjustment to the definition of harm. The new definition should acknowledge that withdrawn projects harm those remaining in the queue beyond cost shifting via queue delay and uncertainty. One suggestion to reducing queue sizes is that MISO establish queue cap rules. These caps, either in the form of regional caps or developer caps per cycle, could limit excessive requests detrimental to other participants and the overall study process. Updating the monetary value placed on entering, remaining in, and withdrawing from the queue will prevent speculative projects from entering the interconnection process. CRA recommends increasing the M2 deposit to a value in the range of $10,000-$14,000/MW and adjusting the M3 and M4 deposit formulas to a minimum of $1,000 to reflect final costs better. CRA also recommends that MISO implement an escalating fixed penalty schedule, including a minimum pre-kick-off stage withdrawal penalty to support the queue cap implementation. The penalty-free withdrawal rules should be updated to consider the overall percentage increase in combined network upgrades and affected system costs. Penalty-free rules should not apply after phase 3.

5. APPENDIX

The table presented below is a revised version of Table 4 from the report, adjusted to reflect median values. We've incorporated this table in response to feedback from stakeholders.

The values in this table support our recommendation for the M2 deposit, particularly when greater emphasis is placed on values from the latest cycles. Giving more weight to values from recent studies offers a more accurate representation of the queue's current status.

Table 6. Network Upgrade Costs, Median Values

Study Cycle	Median of NU Cost per MW, Phase 1	Median of NU Cost per MW, Phase 2	Median of NU Cost per MW, Phase 3	15% of Median NU Cost in Phase 3	20% of Median NU Cost in Phase 3	25% of Median NU Cost in Phase 3
DPP-2017-AUG	$ 89,051	$ 52,000	$ 42,948	$ 6,442	$ 8,590	$ 10,737
DPP-2017-FEB	$ 655,871	$ 111,467	$ 35,815	$ 5,372	$ 7,163	$ 8,954
DPP-2018-APR	$ 67,918	$ 55,860	$ 36,524	$ 5,479	$ 7,305	$ 9,131
DPP-2019-Cycle	**$ 100,511**	**$ 75,228**	**$ 56,814**	**$ 8,522**	**$ 11,363**	**$ 14,203**
DPP-2020-Cycle	**$ 135,621**	**$ 80,175**	**$ 65,872**	**$ 9,881**	**$ 13,174**	**$ 16,468**
Total in-Sample Median	$ 80,624	$ 70,690	$ 48,420	$ 7,263	$ 9,684	$ 12,105

Source: MISO

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 113
Inst. Pol'y Integrity Report

Enough Energy

A Review of DOE's Resource Adequacy Methodology

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July 2025

Institute *for*
Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

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This report does not purport to present the views, if any, of NYU School of Law.

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Executive Summary

On April 8, 2025, President Trump issued an Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) requiring the Department of Energy (DOE) to (1) "identify current and anticipated regions with reserve margins below acceptable thresholds" and (2) "establish . . . a protocol to identify which generation resources within a region are critical to system reliability."[1] DOE responded on July 7, 2025 with its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[2]

This report reviews best practices for analyzing whether a region is resource adequate and for identifying whether a particular resource is critical for resource adequacy. It next analyzes the DOE Study as compared to those best practices. Finally, it examines next steps for U.S. resource adequacy policy following the DOE Study, in light of different entities' respective authorities over the issue.

In Part 1, this report outlines a four-step process for evaluating whether a region is resource adequate and then identifying which resources are critical. Each step involves choices between traditional methods and best practices adapted to the evolving risks posed by the energy transition and the new conditions brought about by climate change.

- *Step 1*: *Set a Resource Adequacy Target*: Planners should define resource adequacy targets using a multi-metric approach that captures not just outage frequency but also magnitude and duration, possibly supplemented by metrics focused on tail risks instead of expected values. Targets should be region-specific and reflect a local cost-benefit analysis that weighs the incremental benefits and costs of achieving reduced outages.
- *Step 2: Conduct Resource Adequacy Modeling:* Rather than focusing narrowly on annual peak load, planners should assess whether a region achieves the target from Step 1 by modeling all 8,760 hours of the year in chronological order using probabilistic techniques that account for uncertainty like the Monte Carlo method. Best practices include incorporating weather-linked dependencies; climate-adjusted inputs; and realistic assumptions about retirements and additions, interregional imports, and storage and demand response dynamics. This modeling more accurately reflects the risks posed by variable generation and energy-limited resources.
- *Step 3: Establish Accreditation Values:* Resource accreditations—the specific contribution of a resource or resource type to resource adequacy—should be derived from Step 2's probabilistic modeling of a resource's ability to contribute during hours of highest risk.

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1 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

2 U.S. Dep't of Energy, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (2025), https://perma.cc/A587-S88S.

Effective Load Carrying Capability or related probabilistic methods should be applied to all resource types, including thermal plants, to accurately describe their contributions under a wide range of possible futures and hard-to-predict risk periods. Accreditation methods should be applied equally to thermal and variable resources to allow for technology-neutral comparisons.

- *Step 4: Calculate the Reference Margin Level and the Reserve Margin:* Using the resource adequacy modeling and accreditation values from Steps 2 and 3, planners should calculate a reference margin level—the amount of accredited capacity that corresponds to achieving the resource adequacy target. Comparing a region's actual resource fleet to this benchmark allows planners to determine whether the exit or entry of specific resources would affect achievement of the reference margin level and thus the resource adequacy target, given the resources' accreditations.

Part 2 compares the best practices from Part 1 to DOE's methodology in the DOE Study—in which DOE concluded that all transmission planning regions except ERCOT are currently resource adequate but that all regions except ISO-NE and NYISO will be resource inadequate in 2030. Across multiple dimensions, DOE's approach departs from best practices in ways that call these results into question.

- *Resource Adequacy Targets:* DOE's use of a multi-metric standard—2.4 hours of lost load per year and 0.002% normalized unserved energy—is consistent with best practices, but the choice of values is not. Neither value is appropriately justified based on a cost-benefit framework, and the use of a one-size-fits-all target for the entire country ignores regional differences. Additionally, DOE inappropriately attempts to label PJM as currently resource inadequate even though the region achieves DOE's own target according to DOE's modeling.

- *Resource Adequacy Modeling:* DOE models all 8,760 hours of the year chronologically but relies on a deterministic rather than probabilistic framework, limiting its ability to assess uncertainty or tail risks. This less accurate approach evaluates adequacy only under a fixed set of historical weather and load years. Further, DOE's truncated description of how its model decides whether an outage has been triggered makes this assumption impossible to fully evaluate, but DOE's limited explanation does suggest that it may have adopted an overly conservative approach that exaggerates resource adequacy risk. Finally, DOE's 2030 results are significantly shaped by unrealistic assumptions about additions, retirements, load, and possibly interregional imports.

- *Accreditation and Reference Margin Levels:* The DOE Study does not attempt to identify resources that are critical for any region's resource adequacy, and thus does not calculate accreditation values or reference margin levels. But DOE does estimate the amount of perfect capacity required to bring certain regions to the 0.002% NUSE target. DOE could build upon this approach in the future to calculate reference margin levels, but any future efforts should attend to all prongs of its multi-metric resource adequacy target. Additionally, DOE's perfect capacity additions inexplicably bring regions far beyond 0.002% NUSE, meaning that DOE overstates how difficult it would be to cure the purported resource adequacy shortfalls.

Part 3 answers what should happen next for U.S. resource adequacy policy now that DOE has published its study.

- Given how DOE's statutory authority under Section 202(c) of the Federal Power Act is limited to emergencies, DOE's own conclusion that most regions are not currently experiencing resource adequacy shortfalls suggests that DOE has limited legal authority to address potential problems in 2030. Moreover, the limitations of the DOE Study call into question the accuracy of DOE's forecasts.
- Instead of DOE, the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation could more appropriately—and less intrusively from the perspective of states, grid operators, and markets—support resource adequacy by issuing reliability standards that require best practices for regions' resource adequacy efforts. Rather than establishing a national resource adequacy target, these standards would govern how regions select resource adequacy targets, evaluate if they are achieving them, and measure the contributions of specific resources. This step would be in line with the Federal Energy Regulatory Commission's Order No. 747, which approved analytical guardrails for resource adequacy analysis for a portion of the U.S.

Introduction

How does a regional electric grid operator know when its region has enough electricity to meet demand and whether any specific generation resource, like a particular coal plant, is essential for doing so? President Trump's Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) implicates these questions: The EO directs the Department of Energy (DOE) to assess if each region of the United States has sufficient energy resources to meet current and future demand, and to identify and retain critical resources.[3] On July 7, 2025, DOE responded to the EO by publishing its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[4]

This report addresses the EO and the DOE Study's fundamental concern: resource adequacy. Resource adequacy is one key aspect of a power system's reliability. It refers to a system's "ability . . . to generate and transmit adequate quantities of electricity to meet demand, taking into account scheduled and reasonably expected unscheduled system outages."[5] Resource adequacy thus concerns whether a system's supply of energy exceeds demand. Determining whether an area is resource adequate is, however, ultimately a policy question, rather than an engineering one, because it would be prohibitively expensive to build a system that serves 100% of demand under all conditions.[6] Deciding whether a region is resource adequate always explicitly or implicitly balances society's desire for reliable electricity with the cost of providing that reliability.

Starting from first principles, Part 1 examines how to determine whether a region meets its selected resource adequacy target and how a planner can know whether any one particular resource is critical for resource adequacy. Part 2 discusses whether the DOE Study reflects, rejects, or obscure these first principles. Part 3 explores next steps for U.S. resource adequacy policy following the publication of the DOE Study, considering the respective roles of the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), DOE, grid operators, and states.

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3 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

4 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2.

5 Burçin Ünel & Avi Zevin, Inst. for Pol'y Integrity, Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System 11 (2018), https://perma.cc/UDB5-DEEM (citing a NERC "Frequently Asked Questions" page that is no longer available).

6 Energy Sys. Integration Grp., New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements 38 (2024), https://perma.cc/NXU4-N4UG.

Part 1: Best Practices for Resource Adequacy

The EO requires DOE to evaluate the sufficiency of regions' "reserve margins" and establish a resulting protocol to identify "critical" resources that should be retained.[7] To figure out what kind of buffer will ensure that a region achieves a given level of resource adequacy, and to label specific generators as essential for that resource adequacy, a planner would need to undertake a four-step process. At each step, the planner must pick between antiquated approaches and newer best practices.

First, the planner must make the policy choice of selecting a resource adequacy target for the region that, if achieved, would indicate resource adequacy. Second, it should use resource adequacy modeling to determine whether a region has achieved and will continue to achieve the selected target under foreseeable future conditions. Third, the planner should use its resource adequacy modeling with accurate data curation to derive how each generation and storage resource contributes to meeting the target (their "accreditation" values). Fourth, it should use the resource adequacy modeling plus resources' accreditation values to derive an acceptable reserve margin for the region (the "reference margin level"). At this fourth step, the planner can use the accreditation values to check whether the exit of a particular resource would cause a region to dip below the reference margin level.

These best practices have largely emerged to address the resource adequacy challenges caused by the energy transition and extreme weather events caused by climate change. Whereas traditional methods have focused on whether demand would exceed supply during peak load hours, system risk has shifted to *net* peak hours, i.e., when load minus variable generation is highest.[8] Measuring whether supply will meet demand has itself become more complicated. Increasingly, it has become important to perform modeling resource adequacy chronologically—each hour reflecting the conditions that came before it—to account for the dynamics of battery storage resources and demand response.[9] And policymakers now are also confronting the outdated idea that thermal resources are "perfect" capacity, given their weather-related vulnerabilities.[10]

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7 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

8 Juan Pablo Carvallo et al., Lawrence Berkeley Nat'l Lab'y, A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems: Institutional and Technical Dimensions 13 (2023), https://perma.cc/5VLY-B7HF.

9 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report 9 (2024), https://perma.cc/KE8D-W6VX.

10 Nat'l Ass'n of Regul. Util. Comm'rs, Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms 32–34 (Nov. 2023), https://perma.cc/K88X-2JCR.

Step 1: Pick a Resource Adequacy Target

Before any analysis can determine if a system is resource adequate, policymakers must set a clear resource adequacy *target*.[11] This first step involves two distinct choices: (1) selecting one or more metrics to represent the variables by which resource adequacy will be judged, and (2) setting the numerical values for those chosen metrics to achieve the resource adequacy target.

Consider what it would take to set a target, not for resource adequacy, but for human health. First, you would pick the metrics that you think would best define whether a person is healthy, e.g., blood pressure, resting heart rate, or cholesterol levels. Using only one metric would not give you enough information. And paying attention to only each metric's average levels without also examining whether the metric ever reaches dangerous levels could obscure risk of a catastrophic health event. Second, you would pick a value for each metric, like a blood pressure of less than less than 120/80 mmHg. To pick that value, you would consider the best available evidence on what level is optimal.

Similarly, when it comes to resource adequacy, the best practice is to move beyond the standard approach of attending primarily to the *frequency* of outages and to also consider their *magnitude* and *duration*. Additionally, regions should consider metrics focused on the extremes of the probability distribution, rather than expected value metrics that could label a system as resource adequate when a low probability (but plausible) event would be catastrophic.

When selecting numerical values for the chosen resource adequacy metrics, the best practice is to consider the best available evidence on the tradeoff between the benefits and costs of additional resource adequacy. The optimal level of resource adequacy may be different in each region, depending on the local costs of the investments that would be needed to reduce shortfall events and the local consequences of a shortfall.[12] A resource adequacy target should ideally represent the level of resource adequacy that the system planner has identified as socially optimal because it balances costs and benefits.

Metrics

Historically, U.S. policymakers have framed their resource adequacy targets in terms of loss of load expectation (LOLE),[13] and this metric remains widespread.[14] LOLE typically refers to the number of days per year in which an outage occurs and is largely a measure of frequency.[15]

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11 *See* Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 2 tbl.1.

12 *Id.* at 39, 41.

13 Elec. Power Rsch. Inst., Metrics and Criteria: Insights from Case Studies and Recommendations and Considerations for Future Practice 31 (2024), https://perma.cc/W4VF-VQPD.

14 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8 tbl.2.

15 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future 3, 8 (Apr. 2022), https://perma.cc/7G9V-CNWB. Technically, the number of days per year in which an outage occurs is "loss of load days" (LOLD), which is a special case of the broader concept of LOLE, which can be used with different event-periods. *Id.* at 7–8. In North America, however, LOLE typically means LOLD. *Id.* at 7; *accord* Gord Stephen et al., *Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric* at 2, https://perma.cc/A9DJ-C3B5.

Frequency is an important characteristic to track because consumers prefer fewer outages.[16] LOLE coarsely accounts for duration, too, in that an outage that stretches multiple days will count as an additional event for each additional day.

LOLE does, however, obscure important aspects of resource adequacy. It will not differentiate between (1) a 10-hour event with 1 GWh of load shed that is followed by a second identical event within the same day and (2) a 30-minute event with 5 MWh of load shed. Customers are not indifferent, however, between these two situations.[17] Because damages depend on outages' frequency, magnitude, and duration, LOLE neglects key dimensions of resource adequacy affecting customers' wellbeing.[18] Attending to these characteristics when setting resource adequacy targets is more important than ever, because changes in the resource mix and extreme weather due to climate change mean that loss-of-load events have become less uniform and thus less interchangeable.[19]

The Multi-Metric Approach

The best practice is to supplement the traditional LOLE metric (or a different frequency-focused metric like "loss of load events," which separately counts all events within a year and thus differentiates between events that occur during the same day[20]) with additional metrics that capture other dimensions of resource adequacy.[21] Both the Electric Reliability Council of Texas (ERCOT) and the Northwest Power and Conservation Council (NWPCC) have done exactly this, augmenting their LOLE-based targets to include magnitude and duration metrics.[22] Under a multi-metric approach, a system could be declared resource adequate if it achieves selected value targets for each and every metric,[23] or if it achieves some minimum number or combination of the metrics (e.g., any two of a system's three metrics).[24]

A leading magnitude metric that could be incorporated into a multi-metric approach is expected unserved energy (EUE): the amount of demand that the system will fail to serve during a period, typically a year.[25] A region's EUE can be contextualized by dividing it by the region's total annual load—this is called normalized unserved energy (NEUE).[26] Australia uses an annual unserved

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16 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

17 *Id.* at 3.

18 *Id.* at 10.

19 *Id.* at 11, 15, 22.

20 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

21 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 33–37; Elec. Power Rsch. Inst., Resource Adequacy Philosophy: A Guide to Resource Adequacy Concepts and Approaches 23 (2022), https://perma.cc/ZH4Y-ZD7J; Juan Pablo Carvallo et al., *supra* note 8, at 28–29; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at vii.

22 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

23 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 35.

24 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 31–32.

25 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

26 *Id.* at 18.

energy metric,[27] as does NWPCC.[28] Planning around these magnitude metrics can help a region avoid catastrophic events associated with significant unserved energy.[29]

But, like LOLE, magnitude-focused metrics like EUE and NEUE are incomplete alone; they do not account for how the unserved energy is distributed throughout the year.[30] An alternative or complementary magnitude metric is "peak shortfall," defined as the largest expected outage of the period.[31] Peak shortfall is potentially useful because damages from a single outage increase nonlinearly with its scale.[32] Both ERCOT and NWPCC have versions of a peak shortfall metric (NWPCC's complements its EUE metric).[33]

For duration, a popular metric that could supplement frequency and magnitude metrics is loss of load hours (LOLH), which measures the number of hours per year in which an outage occurs.[34] LOLH fundamentally resembles LOLE, but is more granular because it analyzes each hour, rather than each day. As such, LOLH does a better job at expressing the aggregate duration of all shortfalls in a region.[35]

Many countries use LOLH as their sole resource adequacy metric,[36] but, in aggregating hours, it neglects the duration of individual events—even though damages increase nonlinearly with an outage's duration.[37] Supplemental metrics such as average shortfall duration[38] and the maximum shortfall length (used in Texas and NWPCC)[39] can capture this aspect of duration.

Accounting for Tail Risks

Beyond questions of frequency, magnitude, and duration, a separate question when using any chosen metric is whether to look at the mean of the distribution, extremes, or both. Traditionally, regions have framed their LOLE, EUE, and LOLH goals in terms of their *mean* values.[40] But the energy transition and climate change have increased the risk of extremely damaging tail risks,[41]

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27 *Id.* at 9.

28 Nw. Power & Conservation Council, *supra* note 22.

29 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 19 tbl.4.

30 *Id.*

31 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide 18 (2024), https://perma.cc/CB7Q-MXZM (using the equivalent phrase "MW Short").

32 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 3.

33 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

34 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

35 *Id.* at 8.

36 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8.

37 *Id.* at 3.

38 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

39 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

40 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment 4 (2023), https://perma.cc/M3A5-2WAL; Juan Pablo Carvallo et al., *supra* note 8, at 12.

41 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 22.

making it increasingly appropriate to factor these risks into regions' metrics.[42] When it comes to resource adequacy, customers care not just about how the how severe and common outages will be on average, but also about how bad the worst outages they will experience could be.

One option for assessing these potentially severe consequences is the "value at risk" method. This method defines the selected metric (whether it is focused on frequency, magnitude, or duration), not in terms of its expected value, but in terms of how bad some relatively unlikely but still plausible scenario would be.[43] For example, one of NWPCC's metrics is the maximum shortfall length, framed in terms of what the maximum shortfall length will be at the 97.5th percentile of the distribution, i.e., how long the shortfall would be if there were only a 2.5% chance that the shortfall could be longer.[44] Planners can also frame a metric both in terms of expected value *and* value at risk for the same system: Belgium previously had an LOLE metric that simultaneously required an expected value of less than 3 LOLH and required the 95th percentile of the distribution to be less than 20 LOLH.[45]

An alternative to the value at risk method is the "conditional value at risk" method, in which the metric is framed not in terms of the value at some percentile of the distribution, but in terms of the average value of the distribution beyond the percentile.[46] Policymakers' preference between these two options will depend on their risk tolerance, as the value at risk method will equally weight all tail events while the conditional value at risk method effectively places more weight on extreme events even within the tail.[47]

Values

After picking resource adequacy metrics—whether singular or multi-valued, and based on expected values, tail risks, or a combination of the two—the second step for setting a resource adequacy target is picking the numerical value for the metric(s). In the U.S., the most common value for the LOLE metric is 0.1, i.e., outages should occur no more than 0.1 days per year.[48] Selecting a value inherently involves balancing customers' desire for resource adequacy with the cost of achieving it.[49]

Notwithstanding that tradeoff, U.S. resource adequacy planners have largely set these values without any economic analysis. The origin of the widespread 0.1 LOLE target is somewhat enigmatic, especially relative to its contemporary significance, but it appears to describe the

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42 *See* Juan Pablo Carvallo et al., *supra* note 8, at 29; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 8; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

43 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

44 Nw. Power & Conservation Council, Pacific Northwest Power Supply Adequacy Assessment for 2029 12 (2024), https://perma.cc/GZY2-PKY7.

45 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 17.

46 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

47 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 27 fig.8.

48 *Id.* at 8.

49 *Id.* at 38.

level of resource adequacy that happened to exist in the 1940s.[50]

The values used in NERC's reports on regions' long-term resource adequacy similarly seem arbitrary. NERC uses a LOLH metric, labeling regions with greater than 2.4 LOLH as high risk, 0.1-2.4 as elevated risk, and less than 0.1 as normal risk. NERC does not explain the basis for these categories, but they appear to stem this from a common (but widely criticized) hourly conversion of the 0.1 LOLE standard.[51] And NERC's values for the NEUE metric—above 0.002% is high risk, less than 0.002% but above zero is elevated risk, negligible or zero is normal risk—is adapted from Australia's 0.002% NEUE target without considering the different national contexts.[52] Context matters because the U.S. and Australia may vary in terms of how damaging outages would be (e.g., how bad it would be to lose electric heating and cooling in light of the region's temperatures) and how expensive it would be to avert them (e.g., the country-specific cost of building a natural gas peaker plant).

A better practice would be to use economic principles to select a socially efficient resource adequacy target, i.e., to select the value at which the incremental costs of additional resource adequacy equal the incremental benefits of achieving it.[53] Where policymakers do estimate the *costs* of improving resource adequacy, they often turn to the concept of "cost of new entry" (CONE).[54] CONE, expressed in $/MWh, represents the marginal investment and fixed costs of adding additional capacity to the system to achieve a more stringent resource adequacy standard.[55] Historically, planners assumed the marginal resource was a combustion turbine, but today it is more accurate to assume a portfolio of diverse resources.[56] Considering CONE by itself, however, does not accurately capture the social marginal cost of achieving higher levels of resource adequacy, because adding capacity can have follow-on effects like reducing the cost of energy.[57] Accordingly, it is better to estimate total net CONE, which nets out potential system benefits such as reduced energy costs for loads and lower operating costs.[58]

To estimate the *benefits* of additional resource adequacy, planners typically rely on the value of lost load (VOLL).[59] The VOLL represents the societal cost of failing to serve a unit of energy

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50 Kevin Carden et al., Nat'l Regul. Rsch. Inst., The Economics of Resource Adequacy: Why Reserve Margins Are Not Just About Keeping the Lights On 2 (2011), https://perma.cc/LS2F-2EZR; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

51 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment 11–12 (2024), https://perma.cc/GJB2-VCZQ; Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

52 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

53 Kevin Carden et al., *supra* note 50, at 1; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 38–42; Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

54 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 13, 41–42.

55 *Id.* at 42.

56 *Id.*

57 Christoph Graf et al., *Cost-Effective Capacity Markets* 29, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4864513 (posted June 21, 2024); Kevin Carden et al., *supra* note 50, at 8–9.

58 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 42.

59 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

demanded by consumers and is denominated in $/MWh.[60] Estimates vary significantly across customer classes,[61] but modelers can capture this through averaging.[62] More challenging is capturing how the VOLL varies with an outage's particular characteristics. For relatively short outages, the first hour tends to the most expensive,[63] indicating that many frequent outages could be more socially disruptive than a consolidated one of equal length. Long-duration outages result in damages that increase nonlinearly (food spoilage, jeopardized medical care, and loss of access to safe drinking water).[64] Similarly, the VOLL can increase nonlinearly with magnitude: When the grid operator can no longer manage the situation through rotating outages, the resulting uncontrolled outage is much more damaging.[65] Accordingly, undertaking a cost-benefit analysis that allows VOLL to vary with duration and magnitude would produce a more accurate, cost-benefit-justified resource adequacy target.

Many jurisdictions use some version a cost-benefit analysis when setting their resource adequacy targets. In the European Union, countries solve for their specific LOLH targets by dividing a local CONE value by the local VOLL, which, in 2023, resulted in a range from 1 LOLH (Sweden) to 15 LOLH (Czechia).[66] The United Kingdom uses this same approach.[67] Australia periodically reviews its 0.002% NEUE target to ensure that the implied "value of customer reliability," which is akin the VOLL, is close to its estimated value.[68] Somewhat analogous to these examples, the administratively set, downward-sloping demand curves for capacity markets in U.S. regions like PJM embody the tradeoff between the benefits and costs of additional resource adequacy, because the curves dictate how much regions are willing to pay for each increment of additional capacity given the capacity's incremental benefits.[69] Technically, though, this cost-benefit thinking happens not when *setting* the resource adequacy target, but in deciding whether to under-, over-, or exactly *achieve* an already-determined target.

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60 Jennifer Danis et al., Inst. for Pol'y Integrity, Transmission Planning for the Energy Transition: Rethinking Modeling Approaches 6 (2023), https://perma.cc/5A6L-DJHL.

61 Michael J. Sullivan et al., Ernest Orlando Lawrence Berkeley Nat'l Lab'y, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States xii, tbl.ES-1 (2015), https://perma.cc/CT53-8WEA.

62 *See* Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

63 Michael J. Sullivan et al., *supra* note 61, at xii, tbl.ES-1.

64 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 23 fig.5.

65 *See, e.g.*, Joshua W. Busby et al., *Cascading Risks: Understanding the 2021 Winter Blackout in Texas*, 77 Energy Rsch. & Soc. Sci. (2021); Sergio Castellanos et al., *A Synthesis and Review of Exacerbated Inequities from the February 2021 Winter Storm (Uri) in Texas and the Risks Moving Forward*, 5 Progress in Energy (2023); Hassan Haes Alhelou et al., *A Survey on Power System Blackout and Cascading Events: Research Motivations and Challenges*, 12 Energies 1, 16–17 (2019).

66 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 39 fig.12, 40.

67 *Id.* at 40.

68 Reliability Panel AEMC, Final Report: Reliability Standard and Settings Review 2018 i, 14 (2018), https://perma.cc/TAN8-TPXZ.

69 *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 76 (2006) ("In addition, we agree with PJM that a downward-sloping demand curve provides a better indication of the incremental value of capacity at different capacity levels than the current vertical demand curve. Under a vertical demand curve, capacity above the Installed Reserve Margin is deemed to have no value. Incremental capacity above the Installed Reserve Margin is likely to provide additional reliability benefits, albeit at a declining level. This value is reflected in the positive (but declining) prices in the sloped demand curve to the right of the Installed Reserve Margin, but is not reflected in the current capacity market.").

Step 2: Conduct Resource Adequacy Modeling

Once the policymaker sets a resource adequacy target, a resource adequacy model can predict whether a region is achieving it (and will continue to do so). Traditionally, modeling was limited to examining whether demand would exceed supply during one or a few peak load hours. But the energy transition, combined with extreme weather from climate change, requires planners to rethink prevailing resource adequacy modeling techniques. For most systems, it is now important to model all 8,760 hours of the year, in chronological order, to accurately capture the risk of load shed.

Along with improving models' temporal resolution, it has become important to make more sophisticated assumptions about modeling inputs. In particular, it has become critical to capture how supply and demand have become more dependent on the weather, which, in turn, has become more extreme. In general, a best practice is to use the Monte Carlo method, and run many (on the order of hundreds or thousands) simulations of grid operations, allowing the model to randomly pull from a distribution of possible values for every input.[70] Additionally, best practices exist for curating the data for each input and their interdependencies, such as representing the relationship between the weather and thermal outages.[71]

Temporal Scope

Historically, resource adequacy modeling focused on the likelihood that supply would exceed demand during one (or a few) top demand hours, ignoring the risk of inadequate supply during the rest of the year.[72] This simplification was more plausible when the grid was dominated by dispatchable resources with relatively predicable outputs.[73]

Now, with the increased penetration of wind and solar, periods of resource adequacy risk have shifted from peak demand to "net peak" demand, defined as load minus energy from non-dispatchable resources.[74] In this new reality, the system is most likely to lack sufficient supply when there is high demand unserved by wind or solar. And, just as weather dictates the performance of these variable resources, it also affects outages at thermal generators (e.g., interruptions of natural gas supply) and load (not just by influencing customers' demand, but also by altering

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70 See Inputs, below, for a more detailed description of the Monte Carlo method.

71 For example, cold winter snaps have historically yielded correlated outages of thermal generators. Nick Wintermantel & Nick Simmons, Astrapé Consulting 8 (2022), https://perma.cc/6D7Y-QCZ2. Similarly, extreme hot weather can require both thermal and nuclear units to cease operations, if the unit can no longer use intake water bodies for cooling. *E.g., High French River Temperatures to Hit Nuclear Production Next Week*, Reuters (June 20, 2025), https://www.reuters.com/business/energy/high-french-river-temperatures-hit-nuclear-production-next-week-2025-06-20.

72 Juan Pablo Carvallo et al., *supra* note 8, at 9; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2.

73 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2; Juan Pablo Carvallo et al., *supra* note 8, at 1, 27.

74 Jill Moraski et al., Clean Air Task Force, Beyond LCOE: A Systems-Oriented Perspective for Evaluating Electricity Decarbonization Pathways 21 (2025), https://perma.cc/3A39-FQLW.

behind-the-meter generation that typically provides "negative" load).[75] Given this confluence of variables, the best practice is now to examine all 8,760 hours of the year when evaluating the likelihood and expected characteristics of shortfalls.[76]

The increased prevalence of energy-limited resources like battery storage and demand response have similarly complicated more traditional resource adequacy modeling assumptions. Battery storage's ability to avoid a resource adequacy shortfall will depend on its state of charge.[77] For example, a battery could have sufficient energy to prevent a shortfall in the morning and then, if it has no opportunity to recharge, be empty for a second event that same afternoon. Similarly, demand response participants have only a limited willingness to curtail or shift their demand; activating the program degrades its later effectiveness.[78] Accordingly, the best practice for resource adequacy modeling is to not just to consider all 8,760 hours, but to do so sequentially, capturing how storage and demand response used in one hour can affect their subsequent availability.[79]

Inputs

To keep pace with the many uncertainties of contemporary resource adequacy analysis, planners have shifted to probabilistic modeling approaches like the Monte Carlo method.[80] Under this best practice, rather than assessing resource adequacy using specific expected values for each input, the user provides the model with a probability distribution for different inputs, and the model randomly samples from those distributions across hundreds or thousands of simulated scenarios.[81] The model will draw the load for each hour, along with potentially correlated variable generation, thermal resource availability, and transmission outages.[82]

While the Monte Carlo method can yield more accurate resource adequacy estimates than simpler methods, its accuracy depends on the user-provided probability distributions, as well as accurate specification of key interdependencies.[83] For weather data, the current best practice is to use as many years as are available, with hourly resolution and geographic granularity.[84] And, especially when forecasting longer-term resource adequacy, it has become important to account

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75 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

76 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

77 Energy Sys. Integration Grp., Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation 11 (2023), https://perma.cc/4ETD-JQK2.

78 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 55–56.

79 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 9; Juan Pablo Carvallo et al., *supra* note 8, at 9; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 44.

80 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 9.

81 *Id.* at 10.

82 Juan Pablo Carvallo et al., *supra* note 8, at 13.

83 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 12.

84 Juan Pablo Carvallo et al., *supra* note 8, at 30.

for climate change projections,[85] including the increasing severity of extreme events.[86]

For load, the best practice is to capture its relationship to the weather, and to add a probabilistically determined amount of distributed generation as negative load.[87] Similarly, for generation, the best practice is to derive the relationship between weather and its output, while also accounting for how technological improvements will improve production profiles,[88] along with the possibility of other types of common mode failures.[89]

Other important considerations include realistic assumptions about electricity imports from neighboring regions (e.g., probabilistically modeling neighbors' operations during tight periods),[90] intraregional transmission constraints,[91] the impact of probabilistic intraregional transmission failures,[92] and for when the model decides that an outage has been triggered.[93]

Additionally, for forecasting longer-term resource adequacy, modelers need to make assumptions about which resources retire and come online. These assumptions will have a large bearing on model outputs. For retirements, modelers should include announced retirements while also forecasting unannounced retirements by accounting for likely retirements due to federal and state policy, age-based retirements, and retirements driven by economics.[94] For near-term new generation and storage, modelers should consider projects that have cleared or will soon clear the interconnection queue, along with expected build times.[95] To anticipate later-term resource additions, modelers should consider resource costs and trajectories, regulatory incentives and barriers, and other relevant drivers. As with other inputs, modelers can implement retirements and additions through a distribution of probabilities, rather than strict assumptions about what will occur.[96]

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85 *Id.*

86 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 22.

87 Juan Pablo Carvallo et al., *supra* note 8, at 31.

88 *Id.* at 32.

89 Elec. Power Rsch. Inst., Modeling New and Existing Technologies and System Components in Resource Adequacy 17–18 (2023), https://perma.cc/3CWR-G5LM; Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 37–38; *How MISO Utilizes PLEXOS for Enhanced Resource Adequacy*, Energy Exemplar (Oct. 9, 2024), https://perma.cc/VQY8-WAVX.

90 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 31; Adria E. Brooks et al., Grid Strategies LLC, Resource Adequacy Value of Interregional Transmission 31 (2025), https://perma.cc/77FQ-L94V; Sam Hostetter & Derek Stenclik, Analysis of Resource Adequacy Across the Eastern Interconnection 7, 16 (2025), https://perma.cc/LCU4-LBZF.

91 Elec. Power Rsch. Inst., Resource Adequacy Scenario Selection Guide 6, (2024), https://perma.cc/FZ5A-5G2M.

92 Juan Pablo Carvallo et al., *supra* note 8, at 13–14; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 12.

93 Kevin Carden et al., *supra* note 50, at 7.

94 Inst. for Pol'y Integrity, Comments on Policy-Driven Retirements in the Context of Order No. 1920 at 4–6 (Oct. 18, 2024), https://perma.cc/GB4R-X55D.

95 *E.g.,* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

96 *See* Inst. for Pol'y Integrity, Comments, *supra* note 94, at 7–8.

Step 3: Accreditation

After resource adequacy modeling, the next step is to derive how much credit each resource deserves for its contribution towards the system's resource adequacy—a process called "accreditation." A resource's accreditation, typically expressed as a fraction of its nameplate capacity, captures the resource's estimated availability during the periods when resource adequacy is most strained.[97]

If a planner is interested in determining only whether a system is achieving its resource adequacy target, this step is unnecessary because Step 2 will accomplish that.[98] Nor is this step strictly necessary to determine how the retirement of any particular resource would affect reaching the resource adequacy target; a planner can accomplish that by re-running Step 2 without the resource included.

But, as explained further in Step 4, accreditation is important to calculate a region's *reference reserve margin*, i.e., the resource adequacy cushion that, when obtained, suggests that the system will achieve its resource adequacy target. Accreditation is also valuable because, once a planner calculates the reference margin level, having these accreditation values can allow a policymaker to quickly estimate how the retirement or addition of particular resources would affect maintaining that margin, without needing to re-run the resource adequacy modeling. This kind of analysis could satisfy the EO's call for a protocol to "identify which generation resources within a region are critical to system reliability."[99]

Historically, planners accredited thermal resources at their full nameplate capacity—reflecting an assumption that they could always generate at maximum capacity during the moments of greatest resource adequacy risk—or accredited them based on their nameplate capacity discounted by their average forced outage rate.[100] Variable resources have often been accredited based on their historical performance during peak load hours.[101]

With the energy transition and climate change, however, the best practice is to derive a resource's accreditation from the resource adequacy modeling described in Step 2 using a probabilistic

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97 An Pham et al., Nat'l Renewable Energy Lab'y, Average and Marginal Capacity Credit Values of Renewable Energy and Battery Storage in the United States Power System 5 (2024) (using the equivalent phrase "capacity credit"). These times have become increasingly decoupled with peak load events. Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 4.

98 Juan Pablo Carvallo et al., *supra* note 8, at 36 ("Capacity accreditation is not inherent to resource adequacy assessments . . . ."); Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at vii ("While resource adequacy analysis assesses whether there are enough resources to serve load across the system, capacity accreditation measures the contribution of individual resources toward meeting that goal, both in terms of capacity and energy.").

99 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15522 (Apr. 14, 2025).

100 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 9, 37; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 5.

101 Juan Pablo Carvallo et al., *supra* note 8, at 36.

method.[102] Probabilistic methods like Effective Load Carrying Capability (ELCC) analyze how slight changes in the modeled resource inputs would affect resource adequacy outcomes.[103] They typically work by adding more of the studied resource to the model, beyond what exists in the base case, and then adding load until the model's base case resource adequacy outcome is restored.[104]

The benefit of probabilistic approaches like ELCC is that, when the modeling inputs from Step 2 are well-curated, the resulting accreditations will more accurately reflect a resource's contribution to resource adequacy during the true risk periods.[105] Additionally, these methods consider a wide range of possible futures, including the possibility of tail events, rather than assuming the future will resemble the past.[106]

The best practice is to apply these ELCC-style methodologies to both variable and thermal resources, storage, and transmission.[107] It is important to treat all resource types equally because capacity accreditation provides a technology-agnostic way of comparing resources' resource adequacy contributions.[108] That purpose is compromised when the resource adequacy value of variable resources is reduced to account for myriad factors affecting their output, without parallel reductions capturing thermal resources' weather dependency and common mode outages.[109] With increased saturation of natural gas resources—which are susceptible to fuel disruptions and extreme weather—it is more important than ever to accurately account for thermal generations' winter risks, especially the risk that a significant amount of thermal capacity will become unavailable at once.[110] Probabilistic methods are ideal for understanding the effect of these risks, including tail risks, in light of the complicated interdependencies of all the factors that dictate the timing of resource adequacy shortfalls.[111]

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102 *Id.* at 36–37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning 24–27 (2011), https://perma.cc/294F-25KU.

103 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 13.

104 *Id.*

105 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 12–14; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 15; Christoph Graf et al., *supra* note 57, at 30. As explained in Step 2 above, these risk periods are becoming harder to predict due to weather's increased influence on supply and demand, and because of increased energy-limited resources in the generation mix.

106 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 14.

107 Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 28; Adria E. Brooks et al., *supra* note 90, at 31.

108 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 32, 37.

109 *Id.* at 37–38.

110 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 24; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 40–41; Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 30; Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 27.

111 *See* Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 11 ("Increasingly, periods of risk are driven by correlation among many components that are often weather-related, including high load, low renewable resource availability, drought, and correlated outages and fuel supply disruptions from the fossil fuel generators."); N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 91 ("If resource performance were to occur at the levels expected during average winter days, the system should be able to serve these high loads. However, resource performance from thermal resources on very cold days, especially natural gas resources, is more likely to be poor. This, coupled with poor performance from solar

Step 4: Calculating the Reference Margin Level and the Reserve Margin

Using Step 2's resource adequacy modeling and Step 3's accreditations, a planner can assess whether a region's fleet would achieve its appropriate reference margin level.[112] The reference margin level typically expresses the amount of accredited capacity that a region would need to achieve its resource adequacy target. The planner will conduct resource adequacy modeling, adding or subtracting additional capacity or load until the system reaches the resource adequacy target. The reference margin level is the sum of the accredited capacity needed to achieve the target.

Once the planner derives the reference margin level (how much total accredited capacity the system requires), it is also possible to answer whether any particular resource is critical to achieving the margin. To check this, the planner would subtract the accredited capacity of the resource in question from the total accredited capacity of the region, and check whether the difference exceeds the reference margin level.

Reference Margin Levels

Historically, reference margin levels were—and, in some places, continue to be—resource adequacy targets in themselves (e.g., a target of accredited capacity that is 15% above peak load).[113] But setting a target framed entirely around the summed accredited capacity, even when informed by years of operating experience at different margin levels, yields a target that does not explicitly aim to achieve any particular outcome.[114] As explained in Step 1, targets are more typically expressed in terms of outcomes: the frequency, duration, and/or magnitude of shortfalls.

Yet the idea of a reference margin level has persisted, as planners often convert their outcome-focused targets into the equivalent reference margin levels.[115] For example, a region might have a 0.1 LOLE target and then determine that the 0.1 LOLE target is achieved when the region's installed capacity has an accreditation of at least 15% above peak load.[116] The same type of translation is possible for targets set using other metrics, like EUE or LOLH.[117]

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resources, results in very low total electricity supply and causes loss-of-load events in the ProbA analysis. The winter load-loss events tend to occur during morning and evening demand peaks and coincide with poor thermal performance and poor solar performance.").

112 This is also commonly referred to as a planning reserve margin, connoting that it includes resources that are in reserve and only be dispatched in highly constrained scenarios.

113 Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 24; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8–9.

114 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 5–6; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 29–30.

115 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 7; Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 1.

116 Juan Pablo Carvallo et al., *supra* note 8, at 28.

117 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 15; Juan Pablo Carvallo et al., *supra* note 8, at 29.

Given how resource adequacy risk has evolved, however, the best practice is to derive the reference margin level using the probabilistic resource adequacy modeling from Step 2 (itself conducted in accordance with best practices).[118] Doing this helps to ensure that the margin is calculated to comprehensively reflect year-round risks. Indeed, when resource adequacy risk shifts beyond peak load hours, the amount of accredited capacity necessary to achieve the resource adequacy target can become *lower* than peak load—because resources' accreditations will be based on their outputs during moments of greatest risk, which may be lower than their outputs at peak load.[119] Accordingly, calculating a reference margin level that matches accredited capacity to peak load would overestimate the necessary margin.

While there are multiple plausible ways to use probabilistic resource adequacy modeling to convert the resource adequacy target to a reference margin level, the general approach depends on whether the modeling reveals that the system is exactly achieving the target, underachieving it, or overachieving it. For the rare case in which the system happens to be exactly achieving the resource adequacy target, then the sum of the total accredited capacity installed on the system equals the reference margin level. It can be expressed as MW of accredited capacity, or in reference to some other amount, like a percentage of peak load.[120]

It is more likely, however, that the system is either above or below the resource adequacy target. In these instances, it is common to add or subtract accredited capacity in the model until the system achieves the target.[121] Then, the reference margin level will be the amount of accredited capacity on the modeled system when the target is achieved, again expressed as a quantity of MWs or as a percentage of peak load.

Effect of Particular Resources

Once the reference margin level and accreditation values have been calculated, it becomes possible to test how the exit (or entry) of a particular resource would affect the region's resource adequacy.

An example is useful in understanding how. Imagine that the reference margin level for a region is 25 GW, and its resource mix has 26 GW of accredited capacity. As is, the region would be exceeding its reference margin level by 1 GW. If any resource with an accreditation greater than 1 GW were to exit the grid, that would cause the actual reserve margin to dip below the reference margin level. Because the reference margin level was calculated following Steps 1–3,

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118 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 6, 11; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 11.

119 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 18.

120 *Id.*; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 6.

121 Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also, e.g.*, MISO, Planning Year 2025–2026 Loss of Load Expectation Study Report 34–35, https://perma.cc/4VV5-4FHU; Western Power Pool, Western Resource Adequacy Program, 102 Forward Showing Reliability Metrics 14 (2024), https://perma.cc/7A6Q-A96E; NYISO, 2024 Reliability Needs Assessment 44 (2024), https://perma.cc/LD5E-RMV9; IESO, Annual Planning Outlook: Resource Adequacy and Energy Assessments Methodology 19 (2024), https://perma.cc/26N7-QC5J.

this dip would indicate that the region can no longer be expected to achieve the resource adequacy target (e.g., 0.1 LOLE) underlying the 25 GW reference margin level. In contrast, any resource with an accredited capacity of 1 GW or less could retire without causing the system to violate its resource adequacy target.

Importantly, this technique for evaluating individual resources' impact works only for relatively small changes to the system, such as the exit or entry of one or a few plants. When larger changes happen in the region's resource composition, the new mix will itself affect resources' accreditation values, because these values inherently depend on the entire fleet composition.[122] To calculate the resource adequacy effect of major changes to the fleet (e.g., the retirement of half of the coal capacity in a region), it would be necessary to re-run the modeling from Step 2 with different inputs.

Having reviewed resource adequacy terms, methodologies, and best practices, Part 2 next uses this understanding to discuss DOE's recent resource adequacy modeling endeavor.

[122] Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 30.

Part 2: DOE's *Resource Adequacy Report*

On July 7, 2025, DOE published its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study), responding to the EO's request for a "uniform methodology to identify at-risk region(s) and guide reliability interventions."[123] The report does not fulfill the EO's separate request for a "a protocol to identify which generation resources within a region are critical to system reliability."[124]

The DOE Study generally examines the resource adequacy of two time periods: today and 2030. According to the study, today, only ERCOT currently fails to achieve DOE's selected resource adequacy targets.[125] Under DOE's assumptions about load growth (including load growth from data centers), resource additions, and retirements, its modeling shows that all transmission planning regions will be resource inadequate in 2030 except ISO-NE and NYISO.[126] When reporting that a region is or would be resource inadequate, DOE sometimes calculates the amount of perfect capacity that could restore the region to resource adequacy.[127]

The DOE Study borrows heavily from NERC's recent Interregional Transfer Capability Study, which analyzed interregional transmission capacity and evaluated how additional interregional capacity could improve resource adequacy.[128] In contrast to NERC's Interregional Transfer Capability Study, the DOE Study does not consider how shortfalls could be mitigated through additional interregional transmission, which can be an alternative to new generation.[129]

Building on Part 1's discussion of how a resource adequacy model's metrics, values, and input assumptions drive its results, this Part evaluates DOE's resource adequacy methodology, including its input choices for load growth, resource additions, and retirements. At each step, it discusses the assumptions embedded in DOE's modeling choices, and reviews why those assumptions provide a weak basis for commanding specific, aging resources to continue serving load at consumers' expense and outside of existing market structures.

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123 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at vi.

124 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

125 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7.

126 *Id.* at 8.

127 *Id.* at 5. The exact meaning of these perfect capacity quantities is unclear due to contradictions within the DOE Study. At times, DOE explains that these are the perfect capacity quantities that restore the system to 0.002% while assuming projected retirements. *Id.* At other points, though, DOE states that these quantities assume no retirements. *Id.* at 9.

128 *Id.* at 2; N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study vi, ix (2024), https://perma.cc/U7M3-L56J.

129 *See generally* Adria E. Brooks et al., *supra* note 90.

Resource Adequacy Targets

The DOE Study uses a multi-metric resource adequacy target of 2.4 LOLH and 0.002% normalized unserved energy (NUSE), which is the deterministic equivalent to NEUE.[130] DOE's decision to use a multi-metric target aligns with best practices, and its decision to use LOLH and NEUE together is reasonable. But DOE's value selections for these metrics are problematic.

For LOLH, DOE indicated that it picked 2.4 because that value "translates into one day of lost load in ten years," i.e., the traditional 0.1 LOLE standard.[131] This decision does not align with best practices for two reasons. First, it seeks to unquestioningly replicate the already arbitrary 0.1 LOLE standard (which merely captures the level of resource adequacy that happened to exist in the 1940s).[132] DOE's choice thus does not reflect any meaningful cost-benefit analysis.

Second, DOE's conversion of 0.1 LOLE to 2.4 LOLH is inaccurate.[133] A region with 0.1 LOLE will experience only one day with an outage—of any length—across ten years, which will be 24 hours in only the most extreme case. A region with 2.4 LOLH will have 24 hours of outages across the decade, across any combination of hours. DOE's selection of 2.4 LOLH metric would therefore, in the vast majority of cases, permit a greater duration and frequency of outages.[134] Although this 2.4 LOLH target might indicate that, all else being equal, DOE's methodology is too permissive, DOE's inputs and assumptions likely dominate its analysis and lead DOE to overestimate potential shortfalls.

Turning to NUSE, DOE reports that it selected 0.002% because NERC uses that same value in its long-term resource adequacy assessments.[135] But, as discussed in Part 2, NERC adopted that value from Australia without any consideration of how the costs and benefits of resource adequacy differ in the U.S. context.[136] In contrast, DOE previously used 0.001% in the National Transmission Planning Study.[137]

Moreover, contrary to best practices, for both LOLH and NUSE, DOE imposes the same resource adequacy target across the entire continental United States, without considering regional differences. As noted in Part 1, when it comes to averting outages, regions face different costs and benefits with regard to resource adequacy and thus different socially optimal levels of resource adequacy.

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130 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4, 14 ("This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.").

131 *Id.* at 4.

132 Kevin Carden et al., *supra* note 50, at 2; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

133 Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

134 Gord Stephen et al., *supra* note 15, at 3, https://perma.cc/A9DJ-C3B5.

135 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4 n.10.

136 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

137 U.S. Dep't of Energy, National Transmission Planning Study: Chapter 2: Long-Term U.S. Transmission Planning Scenarios 4, 82 (2024), https://perma.cc/R8RA-23E2.

Finally, at times, the DOE Study appears to struggle with the very meaning of a resource adequacy standard: It questions both PJM's and SPP's resource adequacy, even though each satisfies the metrics DOE's itself picked for its analysis. For PJM in particular, DOE notes that the region currently satisfies both prongs of the resource adequacy metric, but not for the particular weather year that includes Winter Storm Elliot.[138] Seemingly for this reason, DOE concludes that PJM needs 2.4 GW of additional perfect capacity to be resource adequate now.[139] But DOE's resource adequacy targets are, in DOE's own words, "average indicators" to be achieved across all modeled scenarios, not a requirement that must be achieved in each and every scenario.[140] PJM is resource adequate today according to DOE's targets.

Of course, as discussed in Part 1, it may be reasonable for a system planner to set a resource adequacy target that depends, in part, on each region's performance during tail risks. But DOE has not done so here.

Resource Adequacy Modeling

DOE's resource adequacy modeling is inconsistent with best practices. DOE's high-level decisions about the study's overall modeling approach and data input decisions both diverge from the best practices described in Part 1.

Deterministic Model

While the DOE Study appropriately examines all 8,760 hours of the year in chronological order,[141] DOE departs from best practices by using deterministic modeling rather than a probabilistic approach (like the Monte Carlo method), perhaps because of the EO's relatively short timeline.[142] Rather than randomly sampling probability distributions for each input to construct hundreds or thousands of plausible scenarios, DOE "evaluates whether a power system has sufficient resources . . . under a pre-defined set of conditions which correspond to the past few years of real-world events."[143] DOE uses twelve years of data (2007–2013 and 2019–2023) for weather, load, and generation.[144]

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138 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7, 9, 27.

139 *Id.* at 9.

140 *Id.* at 7.

141 *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10, 12–13.

142 *Id.* at 2. The EO provided an extremely accelerated deadline of 90-days for DOE to produce results. *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025). The DOE Study itself provides additional evidence for this conclusion, with its acknowledgement that "[p]robabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty" but "require more computing power." U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.

143 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10.

144 *Id.* at 11. While DOE uses historical data for the years 2019–2023, it uses "synthetic" data for 2007–2013. *Id.* "The synthetic approach used historical weather data to estimate load and resource availability if those same weather conditions were to occur again in the future. The historic approach used historical measured data for load, as well as wind and solar resource output, from recent years and scaled it appropriately to represent future conditions." N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 74.

By examining whether regions would be resource adequate only under conditions that resemble the recent past, DOE's study does not sufficiently account for uncertainty. Indeed, in the Interregional Transfer Capability Study, from which DOE borrowed, NERC itself explains the limitations of this same deterministic approach and same data: Some regions may look resource adequate because they happened to do well during the twelve years of data, while others look resource inadequate but be unlikely to perform as poorly in the future.[145] Addressing the deterministic vs. probabilistic distinction, NERC cautions that, because a "[p]robabilistic resource adequacy analysis was not conducted[,] . . . . the [Interregional Transfer Capability Study] should not be considered a North American resource adequacy assessment."[146]

DOE grounds its use of a deterministic model in "transparency" and an interest in "model[ing] detailed historic system conditions."[147] Neither is a reason to step away from best practices: DOE could document a probabilistic approach in a transparent way, and relying on a small sample of historic years is less accurate than a probabilistic approach. Given the high stakes associated with resource adequacy planning, any future DOE resource adequacy assessment should prioritize accuracy over expediency.

Outage Threshold

Another modeling choice is the threshold for determining when a shortfall event has occurred. DOE projects a shortfall if "the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario."[148] This choice means that DOE identifies shortfall events in the hours when, after exhausting imports and demand response, a region's excess energy falls below 6% or 3% of hourly load—but it is not clear when DOE uses 6% versus 3%. DOE states that more details are available in a section of the study's appendix entitled "Outputs," but, as of publication of this report, no such section appears to be available.[149]

NERC uses a 3% threshold in its Interregional Transfer Capability Study, using 6% only in a sensitivity analysis.[150] According to NERC, the 3% value "was established based on an evaluation of average reserve requirements where load shed may occur" and reflects how "a Balancing Authority will continue to hold reserves even if involuntary load shed is underway to safeguard the system from cascading or widespread outages."[151] It is impossible to tell from the DOE Study when DOE used 6% versus 3%, but the fact that DOE listed 6% first may suggest that 6% was not limited to a sensitivity analysis.

If DOE's model instead identifies shortage events even when a region still has 6% of load available as spare capacity, then DOE's results depart from NERC's practice and may overstate

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145 *Id.* at 138.
146 *Id.* at 4.
147 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.
148 *Id.* at 12.
149 *Id.*
150 N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 84.
151 *Id.* at 91 n.90, 85.

the extent of expected outages. In NERC's Interregional Transfer Capability Study, this change alone *significantly* altered the existence and extent of predicted outages in many regions, such as producing a 690% increase in the size of the maximum outage event in SERC-Florida.[152] Under the 6% sensitivity, NERC also recommended 58 GW of transmission additions to address resource adequacy instead of 35 GW, illustrating the sizable influence of shifting this assumption from 3% to 6%.[153]

Inputs

DOE's prediction that most regions will experience resource inadequacy by 2030 depends heavily on its assumptions about resource additions, retirements, load growth, and interregional imports. In each instance, DOE makes choices that raise significant questions about the validity of its modeling results.

Additions

DOE assumes that the only resource additions by 2030 will be those NERC currently categorizes as "Tier 1."[154] To be a Tier 1 resource, the resource must have achieved at least one milestone from a NERC list that signifies the unit is "very mature in the development pipeline."[155] This assumption is very conservative: The study itself admits that "[t]his results in minimal capacity additions beyond 2026."[156] In other words, DOE's finding of widespread resource inadequacy in 2030 rests on the assumption that very little will be built from 2027–2030. For example, NERC identifies 17,047 MW of Tier 1 resources slated to come online in PJM throughout 2025 and 2026, but only 1,108 MW from 2027–2030.[157]

The drop-off in Tier 1 resources after 2026 is not due to a shortage of projects in development, but rather because NERC currently classifies much of the capacity that will come online between 2027 and 2030 as "Tier 2."[158] Tier 2 resources occupy a wide range of positions in the interconnection queue, from the earliest stages (e.g., those having completed a feasibility study) to the very end

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152 *Id.* at 105 tbl.8.4

153 *Id.*

154 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4.

155 *Id.* at A-5. More specifically, the resource must have finished construction, be under construction, have a signed/approved interconnection service agreement, have a signed/approved power purchase agreement, have a signed/approved construction service agreement, have a signed/approved wholesale market participant agreement, or (if it is in the footprint of a vertically integrated utility) be included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement. N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

156 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at A-5. *See also* Ric O'Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report*, GridLab (July 11, 2025), https://perma.cc/B3GC-T7GA ("The report assumes just 22 GW of new 'firm' capacity (narrowly defined as gas) is added which is based on NERC LTRA 'Tier 1' – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030**.") (bolded text in original).

157 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 89.

158 *See id.* at 137.

of the process (e.g., those that have requested an interconnection service agreement).[159]

In recent years, the median project has taken approximately 55 months (4.58 years) to go from entering the queue to commercial operation.[160] Extrapolating from this historical trend reveals that a large number of Tier 2 resources will likely be operating by 2030. DOE should have anticipated some of them in the 2030 resource mix, and it departed from best practices by excluding all Tier 2 resources.[161] To do this forecasting accurately, DOE should have examined historical statistics of interconnection queue time by region, resource type, and resource size, along with differentiated queue withdrawal rates, estimating Tier 2 resource additions for each region.[162]

And applying historical statistics for time spent in a region's interconnection queue would itself be a conservative methodology for DOE to use, as FERC Order 2023 and related regional interconnection queue updates are set to speed up waiting times.[163] For example, the DOE Study found a 10.5 GW resource adequacy deficit for PJM in 2030 but failed to consider the almost 12 GW of nameplate capacity—mostly gas—that PJM is fast-tracking through its Reliability Resource Initiative.[164] PJM expects that 90% of this capacity will be online by 2030.[165] PJM is simultaneously pursuing other resource adequacy interventions, including a FERC-approved change to surplus interconnection service (to allow new generators to come online faster by taking advantage of underutilized transmission capacity),[166] and a FERC-pending proposal to expedite the process to transfer capacity interconnection rights from retiring generators to new resources.[167]

Finally, recently "retired" resources represent another potential source of fast additions.[168]

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159 *Id.*

160 Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 41 (2024), https://perma.cc/5DE4-XNK6.

161 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 23 fig.2.

162 *See generally* Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 (2024), https://perma.cc/5DE4-XNK6.

163 *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (2023).

164 Donnie Bielak, PJM, Reliability Resource Initiative: Additional Summaries 2 (2025), https://perma.cc/Y2AB-3CEM; Donnie Bielak, PJM, Reliability Resource Initiative: Results Summary 6 (2025), https://perma.cc/MYQ8-Y53G. *See also* Ric O'Connell, *supra* note 156 ("The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.").

165 *PJM Chooses 51 Generation Resource Projects To Address Near-Term Electricity Demand Growth*, PJM Inside Lines (May 2, 2025), https://perma.cc/8EW2-G2XZ.

166 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,083 (2025).

167 Proposed Revisions to PJM's Open Access Transmission Tariff, PJM, Docket No. ER25-____-000 (Jan. 31, 2025), https://perma.cc/J9T3-MCGL.

168 *E.g.*, Francisco "A.J." Camacho & Daviel Schulman, *Mothballed Nuclear Plant on Brink of Revival*, EnergyWire (July 15, 2025), https://subscriber.politicopro.com/article/eenews/2025/07/15/mothablled-nuclear-plant-on-brink-of-revival-00445239.

Retirements

DOE's assumption that 104 GW of nameplate capacity will retire by 2030 likely overestimates retirements.[169] This number includes both "confirmed" retirements—resources that have notified their system operators of their impending retirements and begun the retirement process—and "announced" retirements—which are publicly stated but not officially noticed.[170] These data come from NERC's Long-Term Reliability Assessment 2024 model.[171] In turn, NERC receives reports of confirmed retirements directly from each region, while announced retirements come from multiple sources, including Energy Information Agency Form 860 data, trade press, and utility integrated resource plans.[172]

These data likely overestimate retirements.[173] First, the economics of energy production have changed since 2024. The combined effect of new demand from data centers and the elimination of federal tax credits for new wind and solar resources improves the financial outlook for thermal resources.[174] Second, federal environmental regulations that would have required thermal resources to make investments reducing their pollution or else retire were projected to result in significant retirements before 2030.[175] But the Trump Administration has begun to rescind or reexamine these rules, which could cause resources to delay their retirements.[176]

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169 *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

170 *Id.* at 12.

171 *Id.*

172 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 28 n.19.

173 Ric O'Connell, *supra* note 156 ("The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.") (bolded text in original).

174 Aurora Energy Research, Impact of Reform to Clean Energy Tax Credits on Investment, Jobs and Consumer Bills 10 (2025), https://perma.cc/VHR5-UEGP; ("Most demand is made up through more production from existing plants (35%), meaning these plants are running for longer hours and/or at higher output levels. Some projects that retired in the base case scenario see longer lifetimes in Tax Credit Removal scenario because of more favorable economics due to clean energy decline (making up 17% of lost generation), and the rest is made up for by new build thermal plants (29%)."); Energy Innovation Pol'y & Tech. LLC, Federal Clean Energy Tax Credits Make Energy More Affordable—A Meta-Analysis (2025) https://perma.cc/QH2E-7PLL ("The research is clear—repealing technology-neutral energy tax credits would raise annual energy bills up to $140–$220 per year nationally, and over $500 per year in some states."). *See also* Ethan Howland, *PJM Capacity Prices Hit Record Highs, Sending Build Signal to Generators*, Utility Dive (July 31, 2024), https://perma.cc/UC6U-QHYT ("Prices in the PJM Interconnection's latest capacity auction hit record highs, which should provide incentives for power plant companies to build new generating resources and keep existing ones operating, according to the grid operator."); Ethan Howland, *MISO Summer Capacity Prices Jump to $666.50/MW-day as Power Supplies Shrink*, Utility Dive (Apr. 29, 2025), https://perma.cc/A6S5-4A4U ("Capacity prices for the upcoming summer season jumped to $666.50/MW-day from $30/MW-day last year across the Midcontinent Independent System Operator's footprint—driven in part by declining surplus capacity, according to the results of its latest planning resource auction released Monday.").

175 PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks 8 (2023), https://perma.cc/7J3A-FL8U.

176 *EPA Launches Biggest Deregulatory Action in U.S. History*, EPA (Mar. 12, 2025), https://perma.cc/55MN-2SUB.

Load

The DOE Study assumes 50 GW of growth in data center load and 51 GW of additional non-data center load.[177] DOE does not account for the possibility that this data center load could be flexible, even as one study suggests that 76 GW of additional data center load could be accommodated today if it could be curtailed only 0.25% of the time, and relevant corporations have confirmed flexibility potential.[178]

In June 2025, Texas enacted a law that allows ERCOT to curtail certain new loads over 75 MW during emergencies.[179] DOE assumes an additional 8 GW of data center load in ERCOT by 2030 and finds a reliability shortfall of 10.5 GW (which is likely an overestimate for the reasons discussed elsewhere in this Part, including how this 10.5 GW brings ERCOT to 0.0008% NUSE instead of 0.002% NUSE).[180] Accordingly, Texas's new law could go a long way towards avoiding the DOE-identified resource adequacy problem. Other regions like PJM are considering strategies to soften the resource adequacy impact of data centers, including ways to better encourage their participation in demand response programs.[181] DOE should have considered the possibility that some of the projected data center load would be flexible, especially in ERCOT.

Additionally, how DOE chose to distribute the projected 50 GW of data center load across regions is questionable. The DOE Study explains it used state-level growth ratios to perform this allocation.[182] But it is unlikely that all the computing demand needs to be processed close to load centers (i.e., proportional to a region's current electric load). In fact, some computing demand

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177 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2–3.

178 Tyler H. Norris et al., Nicholas Inst. for Energy, Env't & Sustainability, Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems 2 (2025), https://perma.cc/6693-3HZU; *EPRI Launches Initiative to Enhance Data Center Flexibility and Grid Reliability,* Elec. Power Rsch. Inst. (Oct. 29, 2024), https://perma.cc/75LY-PSP5 ("Led by EPRI, DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit all electricity consumers. Specifically, DCFlex will establish five to ten flexibility hubs, demonstrating innovative data center and power supplier strategies that enable operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. Demonstration deployment will begin in the first half of 2025, and testing could run through 2027."); Anuja Ratnayake, *Unlocking AI Potential with Data Center Flexibility*, EnergyCentral (June 12, 2025), https://www.energycentral.com/intelligent-utility/post/unlocking-ai-potential-with-data-center-flexibility-PtPoXIAuRMzs5Ff ("In a preliminary test of the depth of computational flexibility possible in an AI data center, the Arizona demonstration site experienced some early success. It showcased the potential for an AI data center to provide grid relief during a peak system event—such as a hot summer day with high power demand—by temporarily and precisely ramping down its electricity consumption without compromising data center performance."). *See also* Ric O'Connell, *supra* note 156 ("It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact.").

179 S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170), https://perma.cc/4Z7H-9XKQ; Brian Martucci, *Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis*, Utility Dive (June 25, 2025), https://perma.cc/SYK3-V4XX; Waleed Aslam & Robin Hytowitz, Elec. Power Rsch. Inst., Texas SB6 Explained: Addressing Large Load Impacts (2025), https://perma.cc/QD8S-3M5C.

180 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 40.

181 Tim Horger, PJM, Large Load Additions Workshop 28 (2025), https://perma.cc/4HSN-CW4W.

182 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 17.

may be served from other regions if it will be cheaper to integrate the data center elsewhere. Given the scale of DOE's projected data center load compared to the relatively small resource adequacy shortfalls that the study identifies, these assumptions may have made the difference between whether a region achieves DOE's resource adequacy targets.[183]

Interregional Imports

The DOE Study states that it has adopted the interregional transfer capacities from NERC's Interregional Transfer Capability Study but also notes that transfers are "available up to the *minimum* total transfer capacity."[184] NERC's values describe the available transmission capacity between regions, including sub-regions of larger transmission-constrained regions like PJM, SPP, and MISO.[185] NERC provides a summer value and a winter value for each interregional interface and for each direction of flow.[186]

It is unclear what DOE means when it says that transfers are allowed up to their "minimum." If DOE picked the lesser of the summer and winter transfer capacities and applied that annually, doing so would inaccurately underestimate the amount of interregional transfer capacity.

Accreditation & Reference Margin Levels

While DOE issued its study in response to the EO's request for a "methodology to identify current and anticipated regions with reserve margins below acceptable thresholds,"[187] it does so through resource adequacy modeling, rather than by calculating accreditation values and using them to derive reference margin levels. As explained in Part 2, properly performed resource adequacy modeling is sufficient to determine whether a region is resource adequate.

In contrast, accreditations and reference margin levels are useful in combination to quickly evaluate how the loss or addition of a particular resource would affect whether a region achieves its resource adequacy target without re-running regional resource adequacy modeling. They are thus more applicable to EO Section 3(c)'s separate command to establish a "protocol to identify which generation resources within a region are critical to system reliability.[188] Thus far, DOE has not released a study implementing this provision. DOE may eventually supplement the DOE Study with additional accreditation and reference margin level analyses.

Nonetheless, while the DOE Study does not calculate accreditation values or reference margin levels, it does undertake the related exercise of evaluating how much additional perfect capacity would bring certain regions to resource adequacy.[189] (DOE calculated these perfect capacity

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183 *See id.* at 9, 17.

184 *Id.* at 18, 12, A-1 (emphasis added).

185 N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 7, 9–10.

186 *Id.* at 17–24.

187 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

188 *Id.* at 15522.

189 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

additions for only four of the seven regions that failed to achieve 0.002% NUSE in 2030: PJM, SPP, SERC, and ERCOT—not MISO, CAISO, or West Non-CAISO.[190]) More specifically, DOE asked how much perfect capacity it would take for regions to achieve the 0.002% NUSE resource adequacy standard in 2030.[191]

If, in the future, DOE were to also calculate the accredited capacity of a region's fleet and then add the solved-for perfect capacity, it could calculate the region's reference margin level. Similarly, although DOE did not perform any perfect capacity analysis for regions that achieve 0.002% NUSE, DOE could subtract perfect capacity from the accredited capacity of the regional fleets to solve for reference margin levels. Once DOE calculates a region's reference margin, it could look at the accredited capacity of any resource to evaluate how its exit or entry would affect achievement of the reference margin level.

In calculating any reference margin levels, DOE should attend to all prongs of its multi-metric resource adequacy target. Here, DOE Study's perfect capacity exercise focuses exclusively on 0.002% NUSE. But if a region achieves 0.002% NUSE and not 2.4 LOLH, it would be resource inadequate according to the terms of this DOE Study. Separate reference margin levels may apply to each prong, and a region would be resource adequate only when the highest reference margin level is achieved.

Additionally, going forward, DOE should better prioritize accuracy in any new studies with respect to calculating a region's need for perfect capacity additions/subtractions. Critically, while DOE asserted that it added the amount of perfect capacity needed to bring each region to 0.002% NUSE, the 10.5 GW that it added to PJM actually brought it to 0.0003% NUSE; the 500 MW added to SERC brought it to 0.0002% NUSE; the 1.5 GW added to SPP brought it to 0.0002% NUSE; and the 10.5 GW added to ERCOT brought it to 0.0008% NUSE.[192] All of these values indicate significantly greater resource adequacy that 0.002% NUSE, sometimes by an order of magnitude.

While DOE explains that its perfect capacity additions were done "by hand with a limited number of iterations (15)" such that the capacity additions "should not be considered the minimum possible capacity to accomplish these targets," that approach does not appear to explain why DOE brought these regions far beyond the 0.002% NUSE target.[193] Rather, this explanation suggests that, for each of the regions, DOE could have achieved these high levels of resource adequacy using less perfect capacity than it added. Accordingly, to achieve 0.002% NUSE, DOE likely could have added much less perfect capacity than it did. Identifying resources that meet these overestimated capacity levels could result in overpaying to achieve a different resource adequacy target than selected.

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190 *Id.* at 20–42.
191 Id. at 5.
192 *Id.* at 27, 30, 32, 40.
193 *Id.* at 19.

Part 3: Next Steps

Having reviewed best practices for resource adequacy modeling and the DOE Study, this final section discusses next steps for U.S. resource adequacy policy considering the diverse actors in this space and their respective authorities.

The Federal Power Act (FPA) gives FERC, and FERC's designated "Electric Reliability Organization" (ERO), NERC, jurisdiction over and responsibility for ensuring "[e]lectric reliability" for the "bulk power system," i.e., the high-voltage transmission network and the energy that flows through it.[194] More specifically, the FPA requires NERC to "establish and enforce reliability standards," which take effect after FERC approves them.[195] Importantly, FERC can also order NERC to submit reliability standards on particular topics and can independently enforce reliability standards.[196] NERC's six regional entities (comprising the continental U.S. plus Canada) also have authority to propose reliability standards to NERC.[197]

Achieving reliability arguably requires that bulk power system be resource adequate because, as FERC explains, "[i]f resources cannot meet load, or are insufficient to provide a reserve margin above expected load, then instability, uncontrolled separation or cascading failures can result from the unanticipated loss of a system element."[198] But, although reliable grid operations depend in part on resource adequacy, the FPA does not put FERC and NERC in the driver's seat for this aspect of reliability. FERC lacks authority to *directly achieve* resource adequacy because it cannot order construction of electric generation facilities.[199] Rather, states retain their traditional authority "over facilities used for the generation of electric energy,"[200] which some exercise by requiring utilities to submit integrated resource plans describing their plans to meet future demand.[201] Other states fully or partially delegate this authority to the Regional Transmission Organizations (RTOs) that operate their regional grids, e.g., by relying on the RTOs to achieve resource adequacy through capacity markets.[202]

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194 16 U.S.C. § 824o(a).

195 16 U.S.C. § 824o(a)(2), (d). FERC does not have authority to create reliability standards directly. *See id.* at § 824o(d).

196 16 U.S.C. § 824o(d)(5), (e)(3).

197 16 U.S.C. § 824o(e)(4); *ERO Enterprise; Regional Entities,* N. Am. Elec. Reliability Corp., https://perma.cc/EQ9E-BXJW.

198 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 25 (2011). Reliable operation also encompasses a second aspect of reliability not implicated by the EO—operational reliability—which refers to "ability of the electric system to withstand sudden disturbances while avoiding cascading blackouts." Burçin Ünel & Avi Zevin, *supra* note 5, at 11.

199 16 U.S.C. § 824o(a)(3). The FPA also prohibits FERC from directing utilities to build transmission, and states retain primary siting authority for transmission. *See id.*; *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 at P258 (2024).

200 16 U.S.C. § 824(b)(1).

201 Coley Girouard, *Understanding IRPs: How Utilities Plan for the Future*, Advanced Energy United (Aug. 11, 2015), https://perma.cc/5MDN-26QY.

202 Dena Adler & Jennifer Danis, Inst. for Pol'y Integrity, Reducing Pollution Without Sacrificing Reliability 14–16

But FERC and NERC can still play an important role for resource adequacy: FERC and NERC, through reliability standards, can ensure grid operators are proactively conducting appropriate resource adequacy assessments and analyses. In Order No. 747, FERC approved a regional reliability standard for conducting resource adequacy assessments.[203] This enforceable reliability standard requires, at a minimum, that entities within the applicable footprint conduct an annual analysis of what reserve margin would be necessary to ensure no more than 0.1 LOLE, using specific inputs like the median load forecast and accounting for important factors like fuel availability.[204] This reliability standard does not require regions to actually achieve 0.1 LOLE, only to conduct the mandated analysis.[205] A future reliability standard could require regions to instead adopt best practices comparable to those described in Part 1.

Turning to DOE, the DOE Reorganization Act put emergency grid reliability powers in DOE's hands for addressing certain emergency situations. Section 202(c) of the FPA empowers DOE, upon the finding of an emergency, to require, among any things, "such generation . . . as in its judgment will best meet the emergency and serve the public interest."[206] Section 202(c) and its implementing regulations, along with the common understanding of the word "emergency," indicate that this authority is limited to unexpected events.[207] Additionally, DOE's implementing regulations indicate that a shortage caused by a resource's poor economics would not qualify as an emergency, unless the shortage is "imminent."[208] When promulgating these regulations, DOE noted that:

> DOE does not intend these regulations to replace prudent utility planning and system expansion. This intent has been reinforced in the final rule by expanding the "Definition of Emergency" to indicate that, while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.[209]

(2024), https://perma.cc/G6J3-9ZL4. These capacity markets are FERC-jurisdictional, and operate according to rules contained in tariffs filed with FERC, specifying particulars like demand curve type, resource accreditation, and formulas for calculating reserve margins. *See, e.g.*, *PJM Interconnection, L.L.C.*, 191 FERC ¶ 61,066, at P 8 (2025).

203 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 1 (2011).

204 Standard BAL-502-RF-03, N. Am. Elec. Reliability Corp., https://perma.cc/9MB5-5H67.

205 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 33 (2011) ("The only obligations under BAL-502-RFC-02 are analysis and documentation requirements. This regional Reliability Standard does not specify how the results of the analysis required in this standard are to be used. For example, BAL-502-RFC-02 does not require state commissions to use the resource assessment analysis resulting from BAL-502-RFC-02 for economic decisions regarding resource adequacy requirements.").

206 16 U.S.C. § 824a(c)(1).

207 16 U.S.C. § 824a(c)(1); 10 C.F.R. § 205.371; Burçin Ünel & Avi Zevin, *supra* note 5, at 37–38.

208 10 C.F.R. § 205.371 ("Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent.").

209 Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39984, 39985 (Aug. 6, 1981) (codified at 10 C.F.R. pt. 205).

In a departure from prior practice,[210] DOE has now used this authority to prevent thermal plants from retiring.[211] These orders have already drawn challenges from multiple parties, including from a politically diverse coalition of utility regulators.[212] Parties argue, among other points, that the plants' retirements were not unexpected; that the regions would be resource adequate even without the plants; and that DOE's newly asserted authority over resource adequacy triggers the major questions doctrine.[213]

Having nationally set best practices and principles for determining resource adequacy in the face of rapidly escalating demand and the clean energy transition could be useful if they are well vetted and use appropriate legal constructs. The FPA in conjunction with the DOE Reorganization Act suggest that the appropriate course of action for the federal government to support resource adequacy would be for NERC and FERC to set national resource adequacy *planning* standards (not a national resource adequacy target) to help regions guard against potential resource adequacy risks that might materialize in the future, instead of allowing DOE to stretch its 202(c) emergency authorities.

The DOE study itself cautions, "the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[214] Despite DOE's press statement asserting that the study's methodology can help guide "guide Federal reliability interventions,"[215] presumably to address the EO's mandate that DOE find a way to routinize further 202(c) emergency orders,[216] the study reports a fundamental limitation for doing so: It does not find any near-term reliability risk from current levels of resource adequacy.

The study itself states that, "one of the key takeaways from this study process is the underscored 'call to action' for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our

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210 Cong. Rsch. Serv., Federal Power Act: The Department of Energy's Emergency Authority 4 (updated 2025), https://perma.cc/AU8L-VR55.

211 *DOE's Use of Federal Power Act Emergency Authority*, U.S. Dep't of Energy, https://perma.cc/DPB9-6B74.

212 Ethan Howland, *Groups Appeal DOE "Emergency" Order Keeping Michigan Plan Online*, Utility Dive (updated June 20, 2025), https://perma.cc/P9YZ-FNLK; Ethan Howland, *Eight Utility Regulators Challenge DOE Order Keeping Michigan Coal Plant* Open, Utility Dive (June 26, 2025), https://perma.cc/55FE-2RYR; Motion to Intervene and Request for Rehearing of the Joint Consumer Advocates, Dep't of Energy Order No. 202-25-4 (June 27, 2025), https://perma.cc/PD74-6CNC.

213 Request for Rehearing by Michigan Attorney General Dana Nessel, Dep't of Energy Order No. 202-25-3, at 27–31, 35–36 (June 18, 2025); Motion to Intervene and Request for Rehearing and Stay of Sierra Club et al., Dep't of Energy Order No. 202-25-3, at 29–36 (June 18, 2025), https://perma.cc/4MYN-MHZC; Petition to Intervene and Request for Rehearing of the Organization of MISO States, Inc., Dep't of Energy Order No. 202-25-3, at 2–6 (June 23, 2025), https://perma.cc/D3PG-56H2. *See also* Brief of the Institute for Policy Integrity at 4–13, V.O.S. Selections, Inc. v. Trump, No. 25-00066-GSK-TMR-JAR (Ct. Int'l Trade May 8, 2025), https://perma.cc/5Z4T-8CHG (describing the major questions doctrine).

214 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at i.

215 *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security*, U.S. Dep't of Energy (July 7, 2025), https://perma.cc/942V-L7VB.

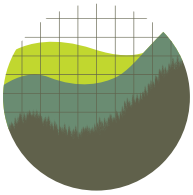
216 *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

collective economic and national security." And it presents a pathway to fulfill DOE's discussion of what will happen next: "The report will inform joint planning processes and help integrate modern metrics into national reliability assessment methodology."[217] FERC directing NERC to develop national resource adequacy planning metrics, protocols, and input parameters would fit neatly within this call to action.

[217] *Reliability*, U.S. Dep't of Energy, https://perma.cc/RSW3-FNN2.

Conclusion

Given ever-increasing demand for electricity—proliferation of data centers for artificial intelligence; electrification of heating, cooling, and transportation; and pushes to onshore manufacturing—maintaining resource adequacy is essential. But there is no single answer to the question of when a system is resource adequate, or even what constitutes resource adequacy. Still, as this report explains, there are better and worse ways to pick resource adequacy targets, to evaluate whether the system has achieved and will maintain them, and to understand the resource adequacy impacts of a particular resource entering or exiting the system. The DOE Study uses some of these best practices but not other important ones, undermining the accuracy of its predictions. The DOE Study will hopefully focus additional attention on resource adequacy and speed up federal and state endeavors already underway to bolster resource adequacy. It does not, however, provide a rational basis for DOE to take action now to thwart ongoing plans for uneconomic, aging resources to retire. DOE's next best step would be to request that FERC open a proceeding eliciting proposals for nationwide, enforceable reliability standards mandating not a national resource adequacy target, but best practices for grid planners to conduct resource adequacy assessments. Additionally, states and grid operators should continue working together to expedite resource permitting, better forecast what hyperscaler demand will materialize, engage in holistic transmission planning, and speed interconnection queues—all of which will support future resource adequacy.



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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 114
IURC 2019 CCGT Order

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH") FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE GAS TURBINE GENERATION FACILITY ("CCGT"); (2) APPROVAL OF ASSOCIATED RATEMAKING AND ACCOUNTING TREATMENT; (3) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR COMPLIANCE PROJECTS TO MEET FEDERALLY MANDATED REQUIREMENTS ("CULLEY 3 COMPLIANCE PROJECT"); (4) AUTHORITY TO TIMELY RECOVER 80% OF THE COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CULLEY 3 COMPLIANCE PROJECTS THROUGH VECTREN SOUTH'S ENVIRONMENTAL COST ADJUSTMENT MECHANISM; (5) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE REVENUE REQUIREMENT FOR COSTS, INCLUDING CAPITAL, OPERATING, MAINTENANCE, DEPRECIATION, TAX AND FINANCING COSTS ON THE CULLEY 3 COMPLIANCE PROJECT WITH CARRYING COSTS AND (B) POST-IN-SERVICE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE CCGT AND CULLEY 3 COMPLIANCE PROJECT UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; (6) ONGOING REVIEW OF THE CCGT; (7) AUTHORITY TO IMPLEMENT A PERIODIC RATE ADJUSTMENT MECHANISM FOR RECOVERY OF COSTS DEFERRED IN ACCORDANCE WITH THE ORDER IN CAUSE NO. 44446; AND (8) AUTHORITY TO ESTABLISH DEPRECIATION RATES FOR THE CCGT AND CULLEY 3 COMPLIANCE PROJECT ALL UNDER IND. CODE §§ 8-1-2-6.7, 8-1-2-23, 8-1-8.4-1 *ET SEQ*, 8-1-8.5-1 *ET SEQ.*, AND 8-1-8.8 - 1 *ET SEQ.*	CAUSE NO. 45052 APPROVED: APR 2 4 2019

DAO
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ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
David E. Veleta, Senior Administrative Law Judge

On February 20, 2018, Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South") filed its verified petition in this Cause seeking, among other relief, certificates of public convenience and necessity for a new duct-fired F-class 2x1 combined cycle gas turbine ("CCGT") providing 700 MW of baseload and 150 MW of peaking capacity pursuant to Ind. Code ch. 8-1-8.5 and for certain environmental projects at its Culley Unit 3 generating station pursuant to Ind. Code ch. 8-1-8.4. Petitions to intervene were filed by the Vectren Industrial Group; Valley Watch, Inc., the Citizens Action Coalition of Indiana, Inc., and the Sierra Club ("Joint Intervenors"); the Indiana Coal Council, Inc. ("ICC"), Sunrise Coal, and Alliance Coal, LLC (the "Coal Parties"); SABIC Innovative Plastics Mt. Vernon, LLC; St. Joseph Energy Center, LLP; St. Joseph Phase II LLC; and Evansville Western Railway. All of these petitions to intervene were subsequently granted. A public field hearing was held in Evansville on July 11, 2018, at which time members of the public presented testimony. The Indiana Utility Regulatory Commission ("Commission") held an evidentiary hearing at 9:30 a.m. on October 9, 2018, in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana.

Based upon the applicable law and the evidence presented, the Commission finds:

1. **Notice and Jurisdiction.** Notice of the hearings in this Cause was given and published as required by law. Vectren South is a "public utility" as defined in Ind. Code § 8-1-2-1(a) and Ind. Code § 8-1-8.5-1, an "energy utility" as defined in Ind. Code § 8-1-8.4-3, and an "eligible business" as defined in Ind. Code § 8-1-8.8-6. Vectren South is subject to the jurisdiction of this Commission in the manner and to the extent provided by Indiana law. Pursuant to Ind. Code chs. 8-1-8.5 and 8-1-8.4, Vectren South may seek Commission approval of Certificates of Public Convenience and Necessity. Accordingly, the Commission has jurisdiction over Vectren South and the subject matter of this proceeding.

2. **Vectren South's Characteristics.** Vectren South is an operating public utility incorporated under the laws of the State of Indiana, with its principal office and place of business in the City of Evansville. Vectren South provides electric and gas utility service to the public in Indiana and is subject to the regulation by this Commission in the manner and to the extent provided by the laws of the State of Indiana. This proceeding pertains to Vectren South's electric utility business. Vectren South renders retail electric utility service to approximately 145,000 customers in seven counties in southwestern Indiana, and owns, operates, manages and controls electric generating, transmission and distribution plant, property and equipment and related facilities which are used and useful for the convenience of the public in the production, transmission, delivery and furnishing of electric energy, heat, light and power for residential, commercial, industrial and municipal uses. Vectren South furnishes such electric utility service to retail customers located in Vanderburgh, Posey, Gibson, Pike, Warrick, Dubois and Spencer Counties, with a major portion of such customers residing in and around the City of Evansville, Indiana. Vectren South owns and operates 1,248 megawatts ("MW") of total net generating capacity. This generation capacity is primarily derived from the following five coal-fired baseload units providing a total of approximately 1,000 MW: A.B. Brown 1 (245 MW), A.B. Brown 2 (245 MW), F.B. Culley 2 (90 MW), F.B. Culley 3 (270 MW) and Warrick Unit 4 (150 MW[1]). Vectren South procures 100% of its coal supply from mines located in Indiana.

[1] Represents Vectren South's ½ interest in Warrick Unit 4, a 300 MW unit.

Vectren South's operations are subject to federal, state and local rules promulgated and/or implemented by, among others, the federal Environmental Protection Agency ("EPA"), the Indiana Department of Environmental Management ("IDEM") and by the Environmental Rules Board of the State of Indiana. Such rules establish environmental compliance standards that govern emissions and discharges from Vectren South's electric generating units.

3. Overview of the Evidence.

A. Condition of Current Fleet.

i. Vectren South. The main drivers behind Vectren South's proposal are the age and operating characteristics of Vectren South's existing baseload capacity and the upcoming deadlines for significant capital investments to address environmental regulations. Mr. Wayne D. Games, Vice President of Power Supply at Vectren South, testified regarding the condition of Vectren South's current generation fleet and the challenges facing the fleet. He testified Vectren South's fleet consists of five coal-fired baseload units totaling 1,000 MW. Mr. Games further testified that growth of renewable energy sources and low natural gas prices have negatively affected MISO's dispatch of Vectren South's coal-fired units. Instead of running continuously, Vectren South's units are now cycled up and down throughout the day, or are shut down altogether, decreasing unit efficiency and increasing wear and tear on the units. Mr. Games testified that because the units were not designed to cycle in this manner, the units cannot effectively compete with gas units in particular, which have far better operating flexibility. Continued market reforms are exacerbating this issue and jeopardizing unit availability and reliability.

Mr. Games also explained that the individual units face additional operating challenges. In particular, the A.B. Brown Units rely on scrubbers that utilize a technology that has been abandoned by the industry because of its high variable costs and the vapor it emits which causes corrosion of the unit structure. The scrubbers are already past their expected 30 year design life and present a significant risk to reliability and maintenance costs. He explained that Culley Unit 2 is Vectren South's oldest and smallest unit and that it has the worst heat rate of any coal unit in the state. Finally, he explained the unique circumstances related to the joint operation of the Warrick Unit which creates uncertainty as to the duration of its operation.

Ms. Angila Retherford, Vice President of Environmental Affairs and Corporate Sustainability, testified regarding two new major federal regulatory initiatives – Effluent Limitations Guidelines ("ELG") and Coal Combustion Residuals ("CCR") - impacting Vectren South's coal-generating units. Absent substantial investment at all of Vectren South's coal plants, they must cease operations by December 31, 2023. Ms. Retherford described Vectren South's environmental compliance strategy for the A.B. Brown and Culley units and testified future compliance costs were modeled in Vectren South's 2016 Integrated Resource Plan ("IRP") under the business as usual scenario. Ms. Retherford testified these rules and other existing federal regulatory requirements will require Vectren South to make significant further investment at the A.B. Brown and Culley generating facilities to continue their operation.

ii. Non-Utility Parties.

(1) OUCC. OUCC witnesses Lauren M. Aguilar – Utility Analyst, Anthony A. Alvarez – Utility Analyst and Peter M. Boerger – Senior Utility Analyst testified regarding Vectren South's request for a CPCN to construct the CCGT. These OUCC witnesses testified Vectren South's decision to construct the CCGT is premature because Vectren South has not explored all practical alternatives to extend the life of the A.B. Brown units. OUCC Witness Aguilar ultimately recommended that the decision to build the CCGT be delayed until the end of the 2019 IRP process, in order to allow Vectren South the opportunity to evaluate additional alternatives. The OUCC offered no alternative resource proposal, but argued for a "blended approach" with the possible continued use of existing assets, and suggested that the necessary expenditures to continue use of these assets could be viewed as buying an "option on the future." The OUCC witnesses asserted that deferring any decision until the conclusion of the 2019 IRP process would still allow sufficient time to take action without affecting reliability.

(2) Coal Parties. The Coal Parties' witnesses generally testified that Vectren South should wait to transition its baseload generation from coal to natural gas because the environmental regulations driving the transition, the ELG and CCR rules, are in flux and not yet final. Specifically, the Coal Parties' witnesses testified that recent and anticipated EPA reconsiderations of the ELG and CCR regulations, as well as the potential stay or replacement of the Clean Power Plan ("CPP"), create the potential scenario where Vectren South could operate the A.B. Brown and Culley units beyond 2023 without the need to make material investments in compliance measures. Coal Parties witness Michael J. Nasi – Partner with the law firm of Jackson Walker L.L.P. – further testified that Vectren South's decision to retire its coal plants is premature. He recommended that the decision be delayed until the environmental regulations driving the decision are better understood. With respect to the A.B. Brown units, the Coal Parties suggested that Vectren should investigate an alternative scrubber technology marketed by a Chinese firm to replace the existing dual alkali scrubbers. This technology which uses ammonia creates material that can be sold as fertilizer with revenues used to offset variable operating costs of the scrubber.

iii. Vectren South Rebuttal. Ms. Retherford, who is also a licensed attorney, testified regarding the risks associated with continuing to operate Vectren South's coal-fired fleet and delaying the decision to construct the proposed CCGT. Ms. Retherford testified that recent legal developments related to the CCR rule have made it impossible for Vectren South to continue operating its coal-fired fleet beyond 2023 without significant capital investment. She testified that the current water discharge permits require, and the groundwater monitoring results at the A.B. Brown and Culley ash ponds confirm, that Vectren South must cease discharging coal ash by December 31, 2023, pursuant to the ELG and CCR rules. She also testified that *Utility Solid Waste Activities Group v. Environmental Protection Agency*, 901 F.3d 414 (D.C. Cir. 2018), 2018 U.S. App. LEXIS 23547, confirms that the CCR Rule is final, including the final compliance deadlines at issue in this proceeding. Ms. Retherford testified that pond retirement delay is not an option, and therefore Vectren South must either make investments to comply with the CCR rule or retire the plants before 2024.

In response to the Coal Parties' position that the current administration could alleviate environmental carbon regulations applicable to the coal units, Ms. Retherford testified that the Administration's proposed replacement for CPP does not alleviate the problems. On August 31, 2018, the EPA published its proposed Affordable Clean Energy ("ACE") rule in lieu of CPP. She explained

that ACE would increase uncertainty and could actually increase the cost of compliance. For units with high heat rates – such as A.B. Brown – ACE would cause significant future compliance costs.

Vectren South also presented the testimony of Richard McMahon from Edison Electric Institute ("EEI") regarding the growing importance of Environmental, Sustainability and Governance ("ESG") reporting and metrics to the financial community, and the focus of all public electric utilities on being responsive to these topics and establishing explicit carbon reduction targets as part of their public disclosures. Mr. McMahon described the coordinated electric industry response to the demands for ESG reporting, and provided specific examples of lenders and large institutional investors who are putting pressure on companies to transition from dependence on coal units. He explained that Vectren South's 60% carbon emission reduction was in line with similar targets publicly disclosed by its electric utility peers. He also presented information regarding the industry transition from reliance on coal to use of gas as part of the ability to reduce carbon emissions.

As to the potential for alternative scrubbers, Vectren South witness Paul Farber – Principal of P. Farber & Associates, LLC – testified regarding the shortcomings of the technologies presented by Sunrise Coal witness Dombrowski and OUCC witness Aguilar and explained why, from an operational and financial perspective, it would not be prudent for Vectren South to adopt those technologies. With respect to the ammonia based scrubber technology presented by witness Dombrowski, Mr. Farber testified the technology has very limited deployment in the United States and would present a number of operational challenges if installed at baseload coal-fired units like A.B. Brown. These uncertainties and risks posed by adoption of this technology include its cost, its impact on operation of the units (including that it might cause Vectren South to be out of compliance with regulations for other constituents such as mercury and particulate matter absent further types of investments), the unknown ability to sell fertilizer output, and the complications associated with dealing with vendors with no domestic history. He discussed in depth the substantial operational burden and health and Homeland Security risk associated with handling the large amount of ammonia required by such a scrubber. Mr. Farber concluded that the Coal Parties had failed to provide any evidence that the capital costs of this scrubber technology would be any less than the scrubber modeled in Vectren South's 2017 IRP Update. In rebuttal testimony, Jon K. Luttrell, Senior Vice President, Utility Operations and President of Vectren Utility Holdings, Inc., also discussed the cyber security complications and risks posed by adoption of Chinese scrubber technology.

Mr. Farber also responded to OUCC witness Aguilar's criticism that Vectren South "only" evaluated wet limestone and her presentation of potential costs for other technologies. Mr. Farber testified that dry scrubbing is not an applicable technology at A.B. Brown for technical and economic reasons, and therefore it was logical for Vectren South to evaluate wet limestone technology at A.B. Brown. He also testified the cost estimates presented by Ms. Aguilar are not comparable cost estimates to replace the existing scrubbers at A.B. Brown Units 1 and 2.

Mr. Games testified on rebuttal that there simply is no time to delay a decision and await the outcome of another IRP. The Vectren South coal units must be retired or retrofitted by December 31, 2023. Given that there has been nothing to suggest more delay would change the overall economics that the F-class 2x1 CCGT is part of the lowest cost solution under every scenario, there is no reason to believe that modeling in the next IRP would change that result. Mr. Games provided an exhibit setting forth a timeline showing that a delay to allow the next IRP to proceed would leave Vectren South with essentially no baseload capacity for almost three years. During that entire period, Vectren

South customers would be completely exposed to the market for capacity and energy. Per the redirect examination of Justin M. Joiner, Director of Regulatory Policy and MISO Affairs for Vectren Utility Holdsings, Inc. ("VUHI"), this would be during the period when MISO is projecting its largest capacity shortfall for Zone 6 (Indiana). The Commission's Director's Report states "[a]n appropriate planning aspiration is to maintain flexibility while also waiting as long as reasonably possible to commit to a resource." Mr. Games testified on cross-examination that Vectren South has waited as long as reasonably possible.

B. Modeling and Results. Only two parties presented modeling evidence and results. Vectren South presented the modeling from the 2017 IRP Update and the 2016 IRP. Sunrise Coal Witness Philip Hayet presented alternative modeling whereby Vectren South's Preferred Portfolio was delayed by seven years in order to allow existing coal units to continue to operate beyond 2023. Other parties offered criticism of Vectren South's modeling but presented no alternative modeling.

i. 2016 IRP. Vectren South's case was filed in the context of a proposed new rule to govern the IRP process. While our new rule was not effective during the 2016 IRPs, all participating electric utilities complied. This new process is significantly more transparent. It includes the participation of stakeholders, the convening of public meetings, and the submission of and response to comments. Mr. Matt Rice, Director – Research and Energy Technologies, testified regarding Vectren South's IRP process and the results of that process. Mr. Rice described Vectren's approach to its 2016 IRP process and testified Vectren South engaged several industry experts, including Burns & McDonnell and Pace Global, to conduct technical modeling. Mr. Rice testified Vectren South worked with these experts and IRP stakeholders to conduct scenario analysis to evaluate 15 portfolios, each representing a different mix of supply and demand side resources to meet customer load over a 20-year time horizon. He further testified Vectren South worked with Pace Global to conduct a risk analysis and evaluate the 15 portfolios using a balanced scorecard approach. From this analysis, Vectren South identified the "preferred portfolio" which consisted of replacing all existing coal fired generation other than Culley Unit 3 as well as gas peaking units Northeast 1 and 2 and Broadway 1 by 2024 with an F-class .05 Fired CCGT. Mr. Rice testified Vectren South incorporated stakeholder input throughout the process and described the steps Vectren South took to engage stakeholders both before and during the process. This engagement included having stakeholders develop two portfolios which were then modeled and included in the risk analysis.

Mr. Matthew Lind – Associate Project Manager, Burns & McDonnell – described the modeling Burns & McDonnell conducted in the 2016 IRP on behalf of Vectren South to evaluate its resource needs over the next 20 years. He testified the results of Burns & McDonnell's modeling identified a low-cost portfolio that ceased coal operations at Vectren South's coal fired facilities (A.B. Brown Units 1 and 2, F.B. Culley Units 2 and 3, and Warrick Unit 4) and replaced this capacity and energy with the combined cycle facility proposed here along with a simple cycle facility. Mr. Gary Vicinus – Managing Director for Utilities at Pace Global – described Pace Global's role in identifying and defining the objectives, metrics and risks in order to select the preferred portfolio among the many options. He testified Pace Global used a balanced scorecard approach to apply a risk analysis to a selection of portfolios ultimately to recommend a preferred portfolio. Mr. Vicinus further testified regarding revisions Pace Global made to its risk analysis and explained that, even with these revisions, the risk analysis indicated the preferred portfolio was the best approach.

Mr. Rice described the preferred portfolio and explained why it ranked the best on the balanced scorecard. He testified it performed the best because the portfolio is diversified as it contemplates keeping FB Culley 3 (a coal unit) and existing wind contracts, building a CCGT and introducing solar and continuing to offer energy efficiency. He further testified it is among the lower cost portfolios (within 4% of the predominantly gas lowest cost portfolio) and ultimately performed best overall when viewed across multiple measures on the balanced scorecard. Because the all-gas portfolio represented the lowest cost portfolio, it is the retention of Culley Unit 3 and the accelerated addition of the 50 MW solar project that increases the costs of the Preferred Portfolio over the lowest cost all-gas portfolio. Retention of coal and the addition of solar are essential to diversity.

ii. 2017 IRP Update. Mr. Lind testified Vectren South requested Burns & McDonnell to update the 2016 IRP modeling and the re-evaluated low-cost portfolio was consistent with the low-cost portfolio identified in the 2016 IRP. He explained that several modeling inputs were updated, including the capital cost for solar resources, variable production costs and revenue requirements for existing units, an assumed operation of Warrick Unit 4 through 2023, and updated cost assumptions for capacity, energy, natural gas, coal, and energy efficiency.

OUCC witness Peter Boerger testified regarding Vectren South's 2017 IRP Update economic modeling. Mr. Boerger testified that Vectren South's 2017 IRP Update did not adequately consider viable options for serving its customers—including making use of existing resources and adequately considering the addition of a smaller CCGT unit rather than the 2x1 unit being proposed. Mr. Boerger also testified Vectren South's modeling of the proposed CCGT understated its capital cost by $200 million, an error which disadvantaged other options in Vectren South's modeling. Mr. Boerger ultimately recommended Vectren South reevaluate its future needs and model additional alternatives.

CAC witness Tyler Comings – Senior Researcher at Applied Economics Clinic – testified on behalf of the Joint Intervenors. Mr. Comings criticized Vectren South's modeling, testifying it was too convoluted to yield a sufficiently transparent or credible result. He testified Vectren South used too many models in the selection of the preferred portfolio and that the use of many models created ample opportunity for flawed and/or inconsistent input assumptions and other settings that could create bias in favor of the preferred plan. Mr. Comings ultimately recommended Vectren South's petition be denied because, in his view, Vectren South did not provide sufficient justification for its choice to build the CCGT and continue the operation of Culley 3.

Indiana Coal Council witness Emily Medine – Principal in the consulting firm of Energy Venture Analysis, Inc. – also testified regarding Vectren South's modeling. Witness Medine testified Vectren South should have fully updated its 2016 IRP analysis, including its scenario analysis, in order to confirm its preferred resource portfolio. She further testified that such an update should include a broader analysis (including sensitivity analyses) of the relevant assumptions and factors as of a time as close to Vectren South filing its Petition as possible. Ms. Medine attributed the decision to build a CCGT to financial motivations and also opined that approval of the CCGT might be a condition to closing the Vectren South merger transaction.[2] Ms. Medine recommended that Vectren South's Petition be rejected because Vectren South has failed to show that proceeding with building the CCGT at this time is prudent, less risky, and a better decision for both customers and the environment.

[2] While this case was pending, it was announced publicly that Vectren South's holding company was the subject of an acquisition at the holding company level, which was the subject of Cause No. 45109.

Mr. Lind responded to Mr. Boerger's testimony about an alleged $200 million "error." He explained that approximately $67 million of the alleged error identified by Mr. Boerger was due to Mr. Boerger's mistaken assumption about whether modeled option costs are stated in 2017 dollars or nominal dollars in the year of incurrence. The remainder is due to Mr. Boerger's efforts to compare apples and oranges. As Mr. Lind explained, the modeling was done prior to the more refined cost estimates for the CCGT that were developed for this case. Rather than based on a design level accuracy of plus/minus 50%, the CCGT design has been refined to a plus/minus 10%. All of the other portfolios were still at plus/minus 50%. As Mr. Lind explained, to compare the other less refined portfolios to the more refined CCGT would require some additional risk factor for the other portfolios. But even if one includes the updated cost estimate, Mr. Lind testified that it doesn't change that the lowest cost portfolios still include the CCGT. Mr. Lind prepared additional modeling involving coal-to-gas conversion (which we will describe later) and which did include the more refined CCGT cost estimate. While this additional modeling used the more precise CCGT cost and therefore impacted every portfolio that included the CCGT by increasing the overall net present value ("NPV") by $54 million, the portfolios that included the CCGT were still the lowest cost portfolios compared to portfolios that did not include the CCGT. Regarding the use of the models, witnesses Lind and Vicinus confirmed that the process and modeling for Vectren South's IRP and risk analysis were consistent with the resource planning approach Pace and Burns & McDonnell have used for numerous other utilities.

(iii) Size of the Proposed CCGT. Joint Intervenors' witness Tyler Comings testified regarding the size of the proposed CCGT. Witness Comings testified that Vectren South has not provided a sufficient justification to build a CCGT of the size included in its proposal. Witness Comings also criticized Vectren South's Request for Proposals ("RFP") (which we will describe in greater detail later) which sought resources between 600 and 800 MW, because he believed Vectren South could have considered combinations of small resources that added up to 600 MW. He further testified that considering smaller options would limit the market risk exposure for ratepayers, as well as permit a combination of bids to make up a least cost alternative. Mr. Comings testified that in order to reduce ratepayers' risk, Vectren South should explore cost effective alternatives that do not require intensive capitalization, but still provide benefits to ratepayers.

OUCC witness Anthony Alvarez also testified regarding the size Vectren South is proposing for the CCGT. Mr. Alvarez testified that Vectren South currently has excess supply, and there is no resource shortfall or inadequacy that supports Vectren's proposed 850 MW CCGT. He also questioned the load forecast used in the IRP and testified Vectren South has excess supply after serving its peak load and therefore has excess capacity to offer into the market and serve new customers.

Industrial Group witness Michael Gorman also testified regarding the size of Vectren South's proposed CCGT. Mr. Gorman testified Vectren South's proposal to build an 850 MW CCGT will result in excess capacity and have a compound impact on Vectren South's cost of service because the plan increases the costs of new generation resources and results in unrecovered stranded costs from the retired resources. Mr. Gorman recommended the Commission implement mitigation measures to reduce the cost burden on customers related to stranded costs and the cost of the new CCGT. He also recommended the Commission modify the off-system sales margin treatment so that 100% of future wholesale revenues be provided to customers to offset the cost of the proposed resource plan.

Vectren South witness Carl Chapman testified on rebuttal regarding Vectren South's decision to construct an 850 MW CCGT. Mr. Chapman explained the CCGT is essentially two units -- a 700 MW baseload unit to replace 730 MWs of retiring coal unit capacity and 150 MWs of duct fired peaking capacity to replace older peaking units and provide available low cost capacity for growth and wholesale sales opportunity. The additional peaking capacity is provided by the decision to duct-fire the CCGT. The incremental cost of duct-firing the CCGT is $15 million, and that decision must be made at the time the CCGT is constructed (i.e., it cannot be added at a later time.) Mr. Chapman testified that if only the unfired 700 MW baseload CCGT is built, then by 2025, Vectren South has a projected surplus above MISO's Planning Reserve Margin ("PRM") (which fluctuates) of only 51 MW. He further testified that by 2030, the surplus is only 5 MWs and by 2031 Vectren South will fail to meet its PRM. He testified that by 2036, Vectren South will be short 39 MWs, and all of this assumes Vectren South will not add significant new load. Mr. Chapman testified that with its low capital cost, firing makes sense from a customer perspective. For an incremental cost of 2%, the firing provides a 21% increase in capacity. Nevertheless, if the Commission approves the baseload 700 MW CCGT without firing, Vectren South will proceed to construct the unfired CCGT to replace its baseload coal units. He stated that Vectren South would also consider investing the incremental $15 million to duct-fire the unit and be at risk to recoup its investment via retention of the wholesale revenue produced by that peaking capacity.

Mr. Chapman also testified regarding Industrial Group witness Gorman's recommendation that Vectren South pass off-system sales margins on to retail customers. Mr. Chapman testified that Vectren South has decided to commit to provide 100% of wholesale sales revenue from the CCGT (baseload and peaking) to customers. Mr. Chapman explained that once the CCGT is placed in rate base, the benefits from the wholesale revenue produced by the unit will go to reduce customer costs. Mr. Chapman testified that providing 100% of wholesale revenue to customers further improves the NPV of the CCGT, will provide a larger offset to customer costs in general, and adds even more support to the $15 million incremental investment to duct fire the unit.

C. <u>Coal Parties' Modeling</u>. Indiana Coal Council, Inc. witness Philip Hayet – Vice President of J. Kennedy and Associates, Inc. – testified regarding Vectren South's 2016 IRP modeling and the 2017 IRP Update. Mr. Hayet testified that Vectren South's modeling analyses were flawed due to errors, inconsistencies, and a lack of consideration of important factors. Mr. Hayet performed his own analysis and testified that using the same model with certain corrections, including a deferral of a decision to add a CCGT, produced a slightly lower cost result on a NPV basis. He predicated his modeling on the assumption that the A.B. Brown 2 scrubber will continue to operate reliably through 2030. He ultimately recommended that Vectren South defer its decision to construct the CCGT.

On rebuttal, Vectren South witness Matthew Lind testified regarding Indiana Coal Council witness Hayet's alternative modeling. Mr. Lind testified that when Mr. Hayet's modeling is corrected for obvious errors, it reaches the same preferred portfolio conclusion as Vectren South's modeling. Mr. Lind provided corrections to Mr. Hayet's modeling in the form of an updated Strategist model and spreadsheets documenting the corrections. Mr. Lind outlined each of the errors he identified in Mr. Hayet's modeling and the impact of the individual errors on his analysis. The first of several errors he identified was that Mr. Hayet failed to include cost escalation during the seven years of delay that he was urging and that correcting this error alone would change Mr. Hayet's overall conclusion that delay would be less costly. Mr. Lind also testified regarding the cumulative effect of

addressing all of the errors. As part of this analysis, Mr. Lind testified that he included the increased cost of the CCGT to reflect the more recent cost estimates based on a plus or minus 10% confidence level. He testified that when correcting Mr. Hayet's modeling for all of these errors and inconsistencies, the NPV favors Vectren South's preferred portfolio, even under Mr. Hayet's no carbon regulation scenario. Witness Hayet corrected his testimony after Mr. Lind filed his rebuttal to add the escalation during the period of delay he was urging, and this correction changed his original conclusion that delay was less expensive. Mr. Hayet did not address the other modeling issues raised by Mr. Lind.

Mr. Games' rebuttal testimony also addressed witness Hayet's assumption that the A.B. Brown 2 unit and scrubber could be operated without added cost and reliability risk through 2030. Apart from the reliability issues created by the frequent cycling of the unit, he explained the structural damage resulting from the corrosive environment created by the unique characteristics of these scrubbers, and based on his direct experience with this equipment, Mr. Games concluded that he could not agree that it would be prudent to continue to operate the A.B. Brown 2 scrubber for another 12 years beyond 2018.

D. Renewables and All-Source RFP. Joint Intervenor witness Tyler Comings criticized the costs assumed in Vectren South's modeling for most renewable energy sources. Mr. Comings testified that Vectren South's forecast of the capital costs of future wind resources is higher than he would have recommended for the type of planning analysis and its forecast of the fixed O&M costs are lower. Mr. Comings recommended the use of the National Renewable Energy Laboratory's Annual Technology Baseline ("ATB") to develop the forecasts. With respect to future solar resources, Mr. Comings testified Vectren South's forecasts are too high for both the capital and fixed O&M costs. Mr. Comings recommended the reliance on the ATB to develop wind and solar price forecasts. For utility-scale PV, he testified that the ATB midpoint projection would be appropriate. As part of his discussion of renewable costs, he noted that Northern Indiana Public Service Company ("NIPSCO") had recently conducted an RFP and obtained solar and wind bids. Mr. Comings testified that Vectren South's overestimation of renewable costs compared to the ATB data biased the modeling results against renewable resources in favor of non-renewable resources, such as natural gas.

On rebuttal, Mr. Lind responded to Mr. Comings' testimony related to the cost of renewables included in Vectren South's modeling. With respect to wind resources, Mr. Lind noted that prior to revising his testimony, Mr. Comings' originally filed testimony included an inaccurate and inappropriate comparison of assumed capital cost for wind resources between Vectren South and ATB because Mr. Comings failed to account for the declining cost curve over time utilized by Vectren South. Mr. Lind testified that when Mr. Comings updated his testimony to reflect this decline, he recognized that Vectren South's wind costs are only "slightly higher" than what Mr. Comings recommends. Mr. Lind further testified that even with this correction, Mr. Comings' comparison to the ATB figures is incorrect because the ATB figure excludes a 2.1% construction finance factor and is thus understated. Mr. Lind testified that when the 2.1% construction finance factor is included, the ATB capital cost will exceed Vectren South's modeled capital cost for wind over more than half of the planning period. Mr. Lind pointed out that Vectren South assumed a higher capacity factor than the ATB survey and also assumed lower O&M costs compared to the ATB survey, and as a result, it is likely that the wind prices recommended by Mr. Comings are actually higher than those modeled by Vectren South.

With respect to Mr. Comings' criticisms of Vectren South's solar costs, Mr. Lind testified Mr. Comings again failed to account for the declining cost curve over time in the original version of his testimony. Mr. Lind further testified that while Mr. Comings did update his comparison to reflect the decline, he did not update it to include the 2.1% construction finance factor in the ATB comparison. Moreover, Mr. Lind explained that the national survey costs relied upon by Mr. Comings were presented on a direct current (DC) basis, whereas the 2017 IRP Update stated cost in terms of alternating current (AC), thus requiring that Comings' costs be converted to AC to allow for a valid comparison to be made. When correcting for these additional errors, Mr. Lind testified the solar costs used by Mr. Comings and Vectren South are nearly consistent over the last half of the study period and fairly similar from 2024 onward, which is the point at which capacity is needed.

Mr. Lind also testified regarding the impact of network upgrades and congestion costs on a portfolio that would rely more heavily on renewables. Mr. Lind testified that a portfolio which would rely heavily on renewables to supply power to Vectren South's customers is more likely to source some or all of these resources remote to Vectren South's service territory given the acreage required for such projects, the grid issues that can be encountered, and the enhanced production that can be obtained in certain locations (e.g., northern Indiana). Mr. Lind explained that when significant amounts of power are sourced from off-system resources, congestion costs to Vectren South's customers increase substantially. Because such costs were not part of the 2017 IRP Update assumptions, Mr. Lind concluded that any small differences between the solar costs presented by Mr. Comings and those modeled by Vectren South would be more than offset by the congestion costs associated with greater reliance on such resources. Finally, Mr. Lind noted that even assuming lower renewable costs could be achieved, such resources would likely displace Culley Unit 3's 270 MWs of capacity because that could be done incrementally to reduce the effects of network upgrades and congestion, whereas the CCGT would remain the optimal low cost choice to replace the remaining 730 MWs of retiring coal capacity in 2023. Further, wind and solar are intermittent sources of power; given that Culley Unit 3 would be Vectren South's only baseload capacity under its preferred portfolio, dispatchable baseload generation from a CCGT provides greater flexibility to respond to intermittent resources.

E. <u>Capacity Price Forecasts</u>. Mr. Comings testified regarding Vectren South's ability to purchase future needed capacity from the MISO market. Mr. Comings testified that Vectren South overestimated future capacity prices in MISO in its modeling, and in reality, the MISO market has had an oversupply of resources and tempered demand, leading to low capacity prices. He testified Vectren South's assumption of higher capacity prices is critical, because it makes the economics of building a new resource more attractive. He concluded that Vectren South was placing risk on its customers if the price of capacity is lower. To reach his conclusion, he relied on the MISO auction clearing results for Zone 6 (Indiana) for the past five years. Indiana Coal Council witness Hayet had a similar criticism of Vectren South's modeled capacity prices. He agreed that the cost of new entry ("CONE") served as the upper end of future capacity prices but that, also based on MISO historic auction clearing prices, it was inappropriate for future assumed capacity prices to approximate CONE. Instead, witness Hayet proposed to use 75% of CONE.

On rebuttal, Vectren South witness Joiner responded to Mr. Comings' testimony related to Vectren South's alleged overestimation of MISO capacity prices. Mr. Joiner testified he disagreed with Mr. Comings' contention that Vectren South should assume it will be able to purchase capacity and energy from the MISO market at low prices based upon recent market conditions. Mr. Joiner explained that the MISO market has been volatile in recent years and is experiencing shrinking

capacity, and such factors have prompted MISO to evaluate changes to its market structure. Mr. Joiner testified that MISO's recent and pending market reform initiatives, including MISO's Resource Availability and Need ("RAN"), are aimed at increasing capacity and energy prices to incentivize new generation development and are thus leading to higher prices as capacity tightens. As such, Mr. Joiner testified that while MISO's historical capacity and energy prices are indicators of recent trends, contrary to Mr. Comings' MISO auction clearing price testimony, they are not good indicators of expected, long-term future pricing. Moreover, the reported potential for a capacity shortfall by 2024 shows the risk of increased market prices.

F. Refueling Options. OUCC witness Boerger recommended that Vectren model a smaller 440 MW CCGT option in conjunction with gas refueling of one or both A.B. Brown units in order to consider a lower capital cost alternative. This option, which replaces retired coal units with a smaller gas baseload unit, was consistent with his stated concern that implementation of large quantities of intermittent renewables could create grid difficulties and that the extension of the life of small coal units is not common in the industry.

Mr. Lind's rebuttal presented the results of additional modeling in response to the OUCC's interest in further analysis related to resource plan options including coal-to-gas conversion that would make use of the A.B. Brown unit boilers. Burns & McDonnell performed that modeling and analyzed four additional portfolios, each where the conversion of one or more units to natural gas was considered. Mr. Lind testified that this updated rebuttal modeling used the more refined cost estimates (at the plus/minus 10% confidence level) for the CCGT for comparison with the coal-to-gas conversion portfolios (which were stated at plus/minus 50% accuracy.) Mr. Lind described the results of the updated analysis and testified that when compared with the coal-to-gas conversion portfolios, the preferred portfolio still produces a lower NPV and projected customer cost. Witness Games explained that this is due in part to the high heat rates of refueled units which result in very poor dispatch rates and resulting reliance on the market for energy needs. He explained that such a portfolio would result in customers significantly depending on market purchases for energy. Witness Games testified the fuel cost per MWhr from a converted gas plant is roughly $20 more expensive than the cost from the proposed CCGT when gas price is $4.000/dkt. He showed the much higher heat rates and lower capacity factors at converted plants that were completed between 2013 through the first quarter of 2018. Mr. Games testified during the hearing that the problem of high heat rates means that the refueled units continue to cycle and ramp up and down when dispatched, leading to wear and tear and the risk of additional maintenance costs.

G. Docket Entry Question & Response. As a follow-up to the additional modeling performed by Vectren South on rebuttal of gas conversion options, we issued a Docket Entry requesting further iterations of gas conversion portfolios. These included refurbishment of Broadway Unit 2 coupled with delays of removal of Warrick Unit 4 and installation of either a simple cycle or combined cycle gas turbine. Vectren South's response included the more refined cost estimate of the CCGT at plus/minus 10%, excluded additional environmental compliance costs at Warrick Unit 4 that would allow for the delay, and were presented with and without the commitment by Vectren South on rebuttal to pass 100% of wholesale revenues to customers if the CCGT is approved. All of the additional modeling requested by our docket entry produced a higher NPV than the lowest cost refueling portfolio presented on rebuttal (to convert A.B. Brown and instill a simple cycle gas turbine). With the sharing of 100% of wholesale revenues, all of the additional modeling produced a higher NPV when compared to the preferred portfolio ranging from 3.5% to 7.0%. Given that the preferred portfolio was within 4% of the lowest cost 2016 IRP portfolio (CCGT, an additional

simple cycle turbine, and delayed renewables), that means the gas conversion portfolios ranged anywhere from 8-12% higher than the lowest cost portfolio.

H. Estimated Cost of CCGT and RFP Process.

i. Vectren South. Mr. Games testified that, consistent with the 2016 IRP results, the 2017 IRP Update, and the Pace risk analysis, Vectren South is proposing to build a CCGT with 700 MW of baseload capacity and 150 MW of peaking capacity to replace retiring coal-fired capacity. Mr. Games testified Vectren South is proposing to build a unit with an output of approximately 850 MWs in order to hold some additional capacity to meet its obligations as a public utility, as well as to serve potential new customers and foster economic development. The 850 MW replaces 865 MW of retiring capacity (730 MW of baseload and 135 MW of peaking capacity, including Broadway Unit 2 in 2025). Mr. Games further testified the estimated cost of the CCGT is $781 million (+/-10%). The estimate includes owner's costs and allowance for funds used during construction ("AFUDC"). This figure was based on cost estimates developed by witness Diane M. Fischer, Central Regional Area Director and Associate Vice President with Black & Veatch. Those estimates were derived from a request for proposals for all equipment comprising the CCGT as well as construction. Mr. Games testified Vectren South is proposing to construct the new CCGT on its existing A.B. Brown generating site which will provide a conservative cost savings of $50 million resulting from reusing the existing site, facilities and equipment. He explained the critical timing of the in-service date of the CCGT which will be operational for the 2023/2024 MISO capacity year in order to retire the Culley 2 and A.B. Brown units and thereby avoid material capital investments otherwise required to operate those units beyond 2023. Similarly, the Warrick Unit 4 joint operating agreement will terminate at the end of 2023. To continue to operate Warrick would also require further investment to comply with environmental regulations.

Mr. Luttrell testified regarding the other replacement generation options Vectren South considered. He described the solicitation of competitive bids for either purchased power or ownership of all or a portion of a new CCGT unit. Mr. Luttrell explained Vectren South engaged Burns & McDonnell to manage the entire power supply RFP process, and testified this process allowed Vectren South to compare the best competitive offers for dispatchable baseload capacity to several self-build alternatives, including a partnership alternative. Mr. Luttrell testified that based on this economic and qualitative comparison, Vectren South made the decision to pursue building the duct-fired version of the proposed CCGT at the existing A.B. Brown site.

Mr. Lind testified in greater depth regarding Burns & McDonnell's role in developing and managing the RFP process to address Vectren South's power supply needs. He testified Vectren South received 11 unique proposals from six different developers. He further testified each of the conforming proposals was ranked and the top two proposals were compared with Vectren South's self-build proposals. Mr. Lind testified that based on NPV cost and qualitative risk factors, including a congestion analysis related to an off-system generation project developed by a third party, Vectren South determined that the self-build option was the best resource for reliable, long term service.

ii. OUCC. Witness Alvarez testified that, while Vectren South conducted an RFP, Vectren South did not competitively bid the actual CCGT it seeks to build in this case. OUCC witness Aguilar testified that Vectren South has not yet identified a manufacturer, chosen an exact type of CCGT, or issued any bids for the project.

iii. Coal Parties. ICC witness Medine criticized Vectren South's RFP process for a number of reasons, including the contention that Vectren South was involved in the process and the self-build project did not submit a bid as part of the RFP process. ICC witness Hayet stated a similar concern. Ms. Medine also disagreed with the position that self-build projects represent less risk than merchant projects. Ms. Medine further testified regarding the risks associated with self-builds, including cost over-runs. She testified that most if not all new Indiana plants have experienced cost over-runs that utilities look to customers to recover, and unless Vectren South is willing to guarantee costs, this is a risk that should be considered.

iv. Joint Intervenors. Witness Comings testified Vectren South did not facilitate a competitive bidding process, which limited resources and discouraged bidders from offering purchased power agreements ("PPAs"). He further testified the RFP should not have been limited to MISO Zone 6 and should have been similar to other investor-owned utility solicitations.

v. Vectren South Rebuttal. Mr. Luttrell responded to the Intervenors' criticisms of Vectren South's RFP process. With respect to Mr. Comings' criticisms that Vectren South did not facilitate a competitive bidding process, including limiting resources and discouraging bidders from offering PPAs, Mr. Luttrell testified Vectren South is retiring over 70% of its baseload capacity and the RFP was specifically designed to fill that deficiency with reliable cost-effective supply identified by the IRP. Mr. Luttrell further testified PPAs were not discouraged and all four of the responsive bidders offered a PPA. Mr. Luttrell also responded to Ms. Medine's criticisms that Vectren South was involved in many aspects of the solicitation and that Vectren South did not submit a bid as part of the RFP Process. Mr. Luttrell testified Vectren South used two separate teams—one focused on the RFP and evaluation and one focused on developing the cost estimate for the Vectren South-build CCGT—and each of these teams were separate and walled off from the other. He testified Vectren South's involvement in the RFP process was critical to help ensure the RFP would meet the needs its modeling indicated was necessary. He further testified he did not believe the RFP process was negatively impacted as a result of the self-build alternative being developed parallel to the evaluation of the RFP bids, and Ms. Medine acknowledges "there is no evidence that there was inappropriate information transfer." Mr. Luttrell explained that ultimately, an evaluation of congestion costs associated with the off-system resource proposal was the driver of selecting the CCGT project at A.B. Brown as the best option.

Mr. Luttrell also responded to Ms. Medine's position that a PPA does not pose a greater risk than having a regulated utility own the generation facility. Mr. Luttrell testified that Vectren South believes that an on-system project at an existing utility site subject to regulatory oversight and financed by a public utility, is less risky than relying on a developer. He further testified that when 70% of baseload capacity is at stake, a utility should consider all risks to project completion and to ongoing service in the long term. Mr. Luttrell provided a real-life, recent example of the risks associated with relying on a developer to construct a project. Further, Mr. Luttrell testified that a PPA does represent greater risk compared to a self-build option because the financing, construction, operation, and future financial stability of the seller is not in control of either the regulated public utility or the Commission. Mr. Lind also explained that while the cost estimate for the CCGT is stated at plus/minus 10%, the risk is actually higher (plus/minus 50%) for all portfolios that do not include the CCGT.

I. Construction of Gas Lateral to Serve CCGT.

i. Vectren South. Mr. Perry Pergola – Director, Gas Supply – testified regarding Vectren South's decision to secure the interstate pipeline services of Texas Gas Transmission ("TGT") to provide natural gas service to the proposed CCGT. He testified Vectren South selected TGT because it was the least cost pipeline option to serve the CCGT at the A.B. Brown location. Mr. Pergola further testified Vectren South will build and operate a new gas lateral to interconnect with TGT and serve the CCGT.

Mr. Steve Hoover – Director of Engineering – testified regarding the 23 mile gas lateral Vectren South will construct to connect the CCGT with TGT. He testified Vectren South will construct the pipeline itself because, by virtue of its experience building, operating and maintaining new or existing gas facilities in the Vectren South service area, Vectren South is uniquely qualified and positioned to construct the new pipeline. Mr. Hoover further testified the estimated cost to construct the gas pipeline is approximately $87 million. This is not included in the estimated cost of the CCGT as presented by witnesses Fischer and Games, as it is expected the costs of the gas pipeline will be reflected in the delivered cost of the gas.

ii. OUCC. OUCC witness Alvarez testified regarding Vectren South's proposal to build the gas lateral to serve the CCGT. He testified Vectren South did not include the costs necessary to build the gas lateral in the $781 million CCGT cost estimate and should have.

iii. Industrial Group. Industrial Group witness Gorman also testified regarding Vectren South's proposal to construct a gas lateral to serve the proposed CCGT. Mr. Gorman testified Vectren South's proposal to self-build the gas lateral is not consistent with protecting the public interest and is anti-competitive. He testified that Vectren South should have considered a third party or TGT to develop the gas lateral. Mr. Gorman testified that to the extent TGT can construct a gas lateral at a lower cost than the Vectren South self-build option, then this option should be adopted. Mr. Gorman further testified that Vectren South's proposal to recover the pipeline costs as part of the fuel costs for the CCGT is not reasonable because the fixed cost to build the gas lateral will not vary with energy generation or volume of gas delivered to the CCGT. He testified instead it would be appropriate to allocate the gas lateral cost as part of the CCGT fixed capital cost of the facility and allocate it on a capacity basis.

iv. Coal Parties. ICC witness Medine testified regarding Vectren South's proposal to construct the gas lateral. Ms. Medine characterized Vectren South's proposal as a proposal to build the lateral using an affiliate without competitive bidding. She also criticized Vectren South's decision to self-build the gas lateral instead of soliciting bids from third parties. Ms. Medine testified that Vectren South did not solicit bids for the lateral from third parties, and, therefore, it cannot represent that it was the lowest cost option for the construction of the lateral.

v. Vectren South Rebuttal. Vectren South witness Steve Hoover responded to criticisms raised by the Intervenors related to Vectren South's proposal to construct the gas lateral. Mr. Hoover testified that Ms. Medine's characterization of the proposal as an "affiliate transaction" has no bearing on the overall substance of the proposed transaction because there are many reasons why it is advantageous for Vectren South to construct the gas lateral. He reiterated that the Vectren South engineering, land services, and construction management teams have already

successfully completed two similar projects to deliver gas to Duke Edwardsport and IPL Eagle Valley generating units. He testified it is therefore in the best interest of Vectren South's customers for it to enlist the experience and expertise of its gas utility in the pipeline construction and operations. Mr. Hoover also responded to criticisms raised by witnesses Gorman and Medine that the lateral project is anti-competitive and being conducted without competitive bidding. Mr. Hoover testified that Vectren South requested TGT to provide a cost estimate to construct the lateral early in the process, and TGT's cost estimate was 10-15% higher than Vectren South's estimate. He further testified that Vectren South will complete a competitive procurement process to select a contractor to construct the lateral. Mr. Hoover testified that during the course of bidding and the evaluation process, Vectren South will also incorporate cost protections and performance incentives to ensure both competitive and fair pricing.

Mr. Hoover also responded to Mr. Gorman's preference that the lateral be placed in Vectren South's rate base as opposed to the costs being recovered via the Fuel Adjustment Clause ("FAC"). Mr. Hoover testified that like IPL and Duke, Vectren South has chosen to have a qualified local distribution company ("LDC") own and operate its gas delivery pipeline. Therefore, the pipeline will not be an electric utility asset and the costs associated with it will be recovered through gas rates.

As to the allegation that Vectren South's owning the gas pipeline as a gas utility asset is anti-competitive, witness Pergola testified on cross-examination that nearly all of the pipeline (more than 22 of the 23 miles of length) is located in Kentucky and therefore presents no opportunity for bypass, because Vectren South does not possess the right to serve customers in Kentucky.

J. Warrick Unit 4.

i. Vectren South. Mr. Wayne Games testified regarding the uncertain future of Warrick Unit 4. Mr. Games explained that Vectren South and Alcoa co-own the unit pursuant to a Joint Operating Agreement ("JOA") whereby each has 50% ownership in the unit. Mr. Games testified that while Warrick Unit 4 will continue to operate in the near term, the long term outlook for the unit is uncertain. He testified the future of the unit is tied to the Alcoa industrial site, and at any time Alcoa could decide to close the smelter unit, which utilizes significant quantities of electricity produced by Warrick Unit 4, based on price volatility in the aluminum market. He testified that the decision to shut down the smelter unit would jeopardize the future of Warrick Unit 4 and this uncertainty makes it difficult to justify investment in the unit or to depend upon it in the long run.

Vectren South witness Carl Chapman also testified regarding the future of Warrick Unit 4. Mr. Chapman testified that Vectren South has agreed to retain its involvement in the unit through 2023 to support the re-opening of the Alcoa smelter. However, he testified beyond 2023 it does not makes sense to continue to invest in a unit that could be subject to shut down if Alcoa decides it has no continuing need for the capacity.

ii. OUCC. OUCC witness Aguilar testified regarding Warrick Unit 4. Ms. Aguilar testified she does not agree with Vectren South's assessments of the risk of continuing to operate Warrick Unit 4 under the JOA and she disagrees with Vectren South's "presentation of the agreement." She further testified that Vectren South could continue to operate Warrick Unit 4 beyond 2023 with environmental compliance updates.

iii. Vectren South Rebuttal. Mr. Games responded to OUCC witness Aguilar's contention that Vectren South could continue to operate Warrick Unit 4 beyond 2023. He testified that due to compliance requirements coming in Alcoa's next National Pollutant Discharge Elimination System ("NPDES") permit, it is anticipated that the unit will require significant capital investment to meet environmental standards in the future. He testified that these investments coupled with the uncertainty related to whether Alcoa will continue to operate Warrick Unit 4[3] under the JOA and performance issues at the unit, warn against continued reliance on Warrick Unit 4.

Mr. Chapman also testified regarding the continued operation of Warrick Unit 4. He testified that the partnership with Alcoa jointly to operate Warrick Unit 4 has become highly uncertain in terms of duration and no longer represents a viable long-term resource option. Mr. Chapman further testified that while Vectren South's IRP recommended retirement of Warrick Unit 4 well before 2023, Vectren South examined each of the coal units to determine whether such units should be retained. He testified that while Culley 3 and Warrick Unit 4 had better profiles in terms of environmental equipment as compared to Vectren South's other units, Culley 3 ultimately had a better operating history based on cost, availability and heat rate. Mr. Chapman reiterated that a strike against continued operation of Warrick Unit 4 is the uncertainty surrounding the longevity of the Alcoa partnership. He reiterated the continued operation of Warrick Unit 4 is dependent on the aluminum market, and if Alcoa's industrial operations cease at the site, the environmental requirements facing Warrick Unit 4 will become significantly more stringent. Mr. Chapman ultimately testified the bottom line is assuming Warrick Unit 4 can continue on post-2023 presents great risk.

As noted previously, in response to our Docket Entry question seeking additional modeling of a portfolio with delayed retirement of Warrick Unit 4, Vectren South indicated that an additional capital investment cost of as much as $50 million may be required to retain the unit if IDEM determines not to renew a variance in the unit's current NPDES permit that allows water discharge at a higher temperature. The new draft renewal NPDES permit allows IDEM to terminate this variance at any time, which will likely require the construction of a cooling tower. Coupled with both Alcoa's and Vectren South's ability to terminate the joint operating agreement, this even further increases the risk of reliance on Warrick Unit 4 beyond 2023.

K. Culley Unit 3. While making investments to preserve some coal-fired generation is not part of the lowest NPV under the 2016 IRP modeling, Vectren South proposes to make investments at Culley Unit 3, its most efficient plant, in order that it may continue to operate beyond 2023. This decision became part of the preferred portfolio as a result of the risk assessment in the 2016 IRP. Preserving Culley Unit 3 promotes greater diversity in fuel sources and it also lessens the impact on the local coal industry. Witness Retherford described the environmental controls that are needed as a result of CCR and ELG. The Culley 3 Compliance Projects consist of (1) conversion of the current wet bottom ash collection system to a dry handling bottom ash system; (2) installation of a spray dryer evaporator system; and (3) the closure of the Culley West ash pond and construction of a new lined process water and storm water retention pond in its place. This new retention pond will be constructed on the location of the existing ash pond due to space limitations. Witness Fischer developed the cost estimates for the former two and Ms. Retherford provided the cost estimate for the latter. Recovery of the associated costs through a rate adjustment mechanism under Ind. Code ch. 8-1-8.4 was opposed by OUCC witness Aguilar and Industrial Group witness Gorman.

[3] With proper notice, Alcoa can also terminate the JOA.

4. Pending Summary Judgment Motion and Motion to Dismiss under T.R. 41(B). On July 19, 2018, the Coal Parties, Joint Intervenors, Evansville Western Railway, the OUCC, and the Industrial Group filed a Motion for Summary Judgment asking the Commission to vacate the schedule, arguing that we cannot grant Vectren South's request for authority to construct facilities until we have completed a "final" statewide analysis pursuant to Ind. Code § 8-1-8.5-3(a). Alternatively, the Movants asked us to grant them an extension of time to file their pre-filed testimony until at least 45 days after we post a "final" statewide analysis. We took the matter under advisement. At the conclusion of Vectren South's case-in-chief, Alliance Coal made an oral motion to dismiss under T.R. 41(B) on the same grounds. The T.R. 41(B) motion was joined by the OUCC and all of the other Movants except the Industrial Group and Evansville Railway.

In construing a statute, we start with its plain language and "attempt[] to give words their plain and ordinary meanings." *Indiana Wholesale Wine & Liquor Co., Inc. v. State ex rel. Indiana Alcoholic Beverage Com'n*, 695 N.E.2d 99, 103 (Ind., 1998) (citations omitted). "[I]n seeking to give effect to the legislature's intent, [the court] read[s] an act's sections as a whole and strive[s] to give effect to all of the provisions so that no part is held meaningless if it can be reconciled with the rest of the statute." *Fort Wayne Patrolmen's Benev. Ass'n, Inc. v. City of Fort Wayne*, 903 N.E.2d 493, 497 (Ind. Ct. App., 2009) (citation omitted).

The Motion is based primarily on Section 3(a) of Ind. Code § 8-1-8.5, which provides that "[t]he Commission shall develop, publicize, and keep current an analysis of the long range needs for expansion of facilities for generation of electricity," and Section 3(c), which provides that "[t]he commission shall consider the analysis in acting upon any petition by any utility for consideration." The Movants interpret these provisions to mean that we cannot consider a certificate of public convenience and necessity ("CPCN") request absent a "final" statewide analysis. We disagree.

Neither provision requires or implies there must be a "final" or conclusive statewide analysis. Nor does any other provision in Chapter 8.5. Section 3 directs us to undertake an "analysis" that is subject to ongoing review and revision. An analysis that must remain "current" cannot possibly remain static or culminate in a finished product. We find that the analysis detailed in the draft and final versions of the Statewide Analysis meets the requirements of the statute.

To the extent the Movants argue that we cannot grant Vectren South's Petition until we complete our annual report on the analysis, their Motion also fails.

Section 3(h) requires us "[e]ach year" to "submit to the governor and to the appropriate committees of the general assembly a report of its analysis regarding the future requirements of electricity for Indiana or this region." Ind. Code § 8-1-8.5-3(h). Section 5(b)(2) provides that a certificate may be granted if the Commission finds the project (A) "will be consistent with the Commission's analysis (or such part of the analysis as may then be developed, if any)"; or (B) is "consistent with a utility's specific proposal submitted under Section 3(e)(1) of this chapter and approved under subsection (d)." Ind. Code § 8-1-8.5-5(b)(2)(A) and (B).

This unambiguous language reflects the Legislature's understanding that new generation needs may arise at a time while the analysis or even the annual report is being developed or under revision. The Legislature granted the Commission authority to issue a CPCN rather than hold the request in abeyance until the annual report is issued.

It must be presumed that "'the legislature intended the language used in the statute be applied logically and not to bring about an unjust or absurd result.'" *D.B. v. Review Bd. of Indiana Dept. of Workforce Development*, 2 N.E.3d 705, 710 (Ind. Ct. App., 2013) (quoting *Penny v. Review Bd. of Ind. Dep't of Workforce Dev.*, 852 N.E.2d 954, 960 (Ind. Ct. App., 2006), trans. denied). Reviewing bodies also avoid "interpreting a statute in such a manner as to render its provisions mere surplusage." *Id.* (citing *In re Adoption of D.C.*, 887 N.E.2d 950, 959 (Ind. Ct. App., 2008). The Legislature cannot have meant for the Commission to hold off assessing petitions until its analysis becomes "final" (which will never occur), or even until its annual report is submitted. Thus, the statute is clear that in considering a CPCN request, pursuant to Section 5(b)(2) we can rely on whatever current statewide analysis exists or simply determine whether the proposal is consistent with the utility's own plan and reports.

In sum, the Commission retains authority to review a project at any time. Ind. Code § 8-1-8.5-5.5 expressly allows us to "commence a review of any certificate granted under this chapter" when, "in the opinion of the commission, changes in the estimate of the probable future growth of the use of electricity" call for such review. Further, "[i]f the commission finds that completion of the facility under construction is no longer in the public interest, the commission may modify or revoke the certificate." Id.

For all of the foregoing reasons, and each of them, the Motions for Summary Judgment and for Dismissal under T.R. 41(B) are denied.

5. Commission Discussion and Findings.

A. Vectren South's Request for a CPCN for a CCGT. Vectren South requests a CPCN for a proposed CCGT (approximately 850 MW) to be constructed at the current site of the A.B. Brown power plant in Posey County. Under Chapter 8.5, a public utility may not begin the construction, purchase or lease of any steam, water, or other facility for the generation of electricity to be directly or indirectly used for the furnishing of public utility service without first obtaining from the Commission a certificate that public convenience and necessity requires, or will require, such construction, purchase or lease.

In considering a CPCN request, Chapter 8.5 requires the Commission to consider options other than the construction, purchase, or lease of an electric generating facility. *See* Ind. Code § 8-1-8.5-4.

Further, Ind. Code § 8-1-8.5-5 sets forth specific findings the Commission must make in order to approve and grant the requested CPCN. First, the Commission must make a finding, based on the evidence of the record, as to the best estimate of construction costs. Second, the Commission must find that either (a) construction will be consistent with the Commission's Statewide Analysis, if any, for the expansion of electric generation facilities, or (b) the proposed construction is consistent with a utility-specific proposal as to the future needs of consumers in the State of Indiana or in the petitioning public utility's service area [i.e., the utility's IRP]. Third, the Commission must find that public convenience and necessity require the facilities for which the CPCN is requested.[4]

[4] A fourth finding relating to coal-consuming facilities, pursuant to Ind. Code § 8-1-8.5-5(b)(4), does not apply to the proposed natural gas facilities.

"We have indicated in previous CPCN cases that 'least-cost planning' is an essential component of our [CPCN] law." *Joint Petition of PSI Energy, Inc. and CINCAP VII, LLC*, Cause No. 42145, at 4 (IURC Dec. 29, 2002), *quoting Southern Indiana Gas & Electric Co.*, Cause No. 38738, at 5 (IURC Oct. 25, 1989). "We have defined 'least-cost planning' as a 'planning approach' which will find the set of options most likely to provide utility services at the lowest cost once appropriate service and reliability levels are determined." *Id.* "However, we have emphasized that the [CPCN] statute does not require the utility to automatically select the least cost alternative. Nor does the statute require the utility to ignore its obligation to provide reliable service or to disregard its exercise of reasonable judgment as to how best to meet its obligation to serve." *Id.* As this Commission has previously ruled: "[i]f an Indiana utility reasonably considers and evaluates the statutorily required options for providing reliable, efficient, and economic service, then the utility should, in recognition that it bears the service obligations of IC 8-1-2-4, be given some discretion to exercise its reasonable judgment in selecting the option or options to implement which minimize the cost of providing such service." *PSI Energy, Inc.*, Cause No. 39175, at 14 (IURC May 13, 1992); *see also Joint Petition of PSI Energy, Inc. and CINCAP VII, LLC*, Cause No. 42145, at 4.

The pre-approval of long-lived power plant investment and the concurrent regulatory assurance of that investment's recovery is, at its base, the creation of fixed costs that customers will be required to pay several years into the future, perhaps as long as 30 years or more into the future. Accordingly, our consideration in this and other pre-approval requests, especially in periods of seemingly quickening technological change, must not ignore the risk that any such investment may become uneconomic over the long-term. We must acknowledge that the economic forces at work may come from other supply side options or even demand side opportunities. The supply side and demand side certificating statutes implicate this by recognizing that an optimal balance of energy resources should consider both aspects in meeting customer needs.[5] A complication in the optimizing effort is the often disparate time horizons of the supply and demand sides of the balance. The inability to adjust the long-lasting nature of the supply side of the equation in the event market conditions or demand side expectations change in a lesser time horizon introduces a risk that some measure of the supply side investment may become uneconomic within its lifetime.[6] Demand side efforts by customers as a result of the uncontroverted improving economics of customer-scale generation resources may further compound the challenge of the optimal balancing act. Reducing demand in the near term does not necessarily correspond with reduced assured supply side investment cost recovery.[7] Because unwinding assured cost recovery should an asset become uneconomic is not a commonly employed regulatory option, it is prudent to ensure during the pre-approval process that we understand and consider the risk that customers could sometime in the future be saddled with an uneconomic investment. Outcomes that reasonably minimize such potential risk and serve to foster utility and customer flexibility in an environment of rapid technological innovation on both the utility and customer side of the meter are, therefore, a lens through which we will review Vectren South's request.

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[5] Indiana Code §§ 8-1-8.5-4 and -10(c)(3).

[6] This effect can be see through the recovery of lost revenues a statutory component of utility DSM programs, which is in part a function of investment, of fixed cost, that is not being consumed at the expected rate.

[7] This timing inconsistency can reduce the value of demand side efforts because they are not avoiding long-lived fixed costs previously approved and included in rates. The full incremental impacts of demand side actions which occur after the approval of long-lived fixed costs are only affected over longer periods of time when future resources must be acquired and the timing and type of resource might change as a result of cumulative demand side activities.

i. Ind. Code §§ 8-1-8.5-4.

(1) Ind. Code § 8-1-8.5-4(1). In evaluating a utility application for approval to construct new generation, the Legislature has directed us to take into account the utility's "current and potential arrangements with other electric utilities for (A) the interchange of power; (B) the pooling of facilities; (C) the purchase of power; and (D) joint ownership of facilities."

As a member of MISO, Vectren South interchanges power on a daily basis, and Vectren South's modeling considered and factored this arrangement into its decision to seek a CPCN. In addition, early in its resource selection process Vectren South identified a potential partner for a joint generation project. Witness Luttrell explained that this partner was interested in owning a minority share of a larger CCGT, and agreed to study locating such a unit on Vectren South's system. As studies ensued, the partnership appeared to be a viable resource option. As a result, the parties studied this joint ownership opportunity throughout 2017, but ultimately in January 2018 the potential partner provided notice that it would not proceed with such a project. Both Vectren South and the Commission have considered the interchange of power and pooling of facilities.

When assessing a CPCN petition, the Commission also considers the potential purchase of power by Vectren South. On June 20, 2017, Vectren South issued a RFP for dispatchable resources located in MISO Zone 6. Vectren South explained that its RFP specified this location requirement in order to satisfy MISO's requirement that a load serving entity have at least 67% of its resources located within its zone. The RFP sought dispatchable resources based upon the 2016 IRP analysis, which recommended that Vectren South retire nearly all of its baseload coal-fired capacity by the end of 2023. As a result, the RFP was designed to solicit baseload capacity to replace the 730 MWs provided by the retiring coal units. In response, Vectren South received nine qualified bids offering both PPAs and offers to build a CCGT and sell that unit or a partial interest in that unit to Vectren South. Using the expertise of Burns & McDonnell ("BMC"), Vectren South evaluated both quantitative and qualitative aspects of the competing bids. Based on BMC's analysis of the levelized cost of energy ("LCOE") of the bids, Vectren South selected the bid with the most favorable LCOE to compare to a self-build option. BMC's analysis was that Vectren South's self-build option had a better net present value than this best bid, and also exposed Vectren South to less risk versus long-term reliance on a merchant developer. Vectren South's rebuttal testimony noted that the merchant developer in question had in fact, even prior to its bid submission, withdrawn its project from the MISO queue without informing Vectren South.

The Commission acknowledges Vectren South's issuance of an RFP but believes the RFP was unduly restrictive given the rapid changes in technology and costs being seen in the market, especially regarding renewable energy. The narrow RFP with its focus on a large baseload dispatchable resource limited the options Vectren South evaluated to those larger than 600 MW. As a result, Vectren South foreclosed consideration of combinations of smaller resources that might have offered greater resource diversity, flexibility and cost efficiencies than reliance on the acquisition of a single large natural-gas facility. As discussed further below, expansion of the RFP to consider a broader spectrum of resource options would have also gone a long way to improve the metrics to limit risks from exposure to changes in market conditions and technologies.

Based on Vectren South's unduly restrictive RFP the Commission cannot conclude that Vectren South thoroughly evaluated the purchase of power in connection with Vectren South's request.

(2). Ind. Code § 8-1-8.5-4(2).

(a) The Refurbishment of Existing Facilities. In acting upon a petition for the construction of an electric generation facility, we must consider other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities. Ind. Code § 8-1-8.5-4(2). Ms. Aguilar summarized the following alternatives that Vectren South failed to fully analyze: (1) Retain Coal at Vectren South's existing plants and invest in refurbishments; (2) Retain the agreement with Alcoa for Warrick Unit 4; (3) Refuel the A.B. Brown unit(s) with gas; (4) A blended option, such as refueling one or more A.B. Brown units to gas and building a smaller CCGT; (5) Enter into a PPA with one of the bidders who responded to Vectren South's RFP; and (6) Retain its Broadway Avenue Unit 2. Pub. Ex 1, p. 8. Ms. Aguilar argued that Vectren South unfairly screened out these alternatives during the IRP process.

We agree with Ms. Aguilar and Dr. Boerger that Vectren South did not fully consider options to extend the life, or refurbish, existing units as required by Ind. Code § 8-1-8.5-4(1). *Id.* and Pub. Ex. 3, p. 6. This failure began during Vectren South's IRP process, when Vectren South screened out, without further study, viable refurbishment options. Pub. Ex. 1, p. 11. Vectren South's stated reason for shutting down the A.B. Brown units is premised on the need to replace the flue-gas desulfurization ("FGD") units at a cost of approximately $350 million. Pub. Ex. 3, p. 7. Dr. Boerger stated that with the exception of the current FGDs, the units operate quite well and are sized appropriately for a small utility like Vectren South. But as noted by Ms. Aguilar and Dr. Boerger, Vectren South's chosen FGD replacement technology was the most expensive and only technology reviewed. *Id.,* Pub. Ex. 3. Dr. Boerger pointed out that Vectren South did not consider lower-cost FGD replacement options, even though such options were available. He said that this decision made the continued use of the A.B. Brown units look less attractive in modeling than if those options had been included. A reasonable alternative would have been the refurbishment of these units through refueling. Pub. Ex. 3, p. 7. Refueling is viable, proven technology that could be accomplished at a fraction of the price of the CCGT – approximately $45 million for both A.B. Brown units.

Vectren South considered a smaller 440 MW CCGT option in its last IRP, but Vectren South did not include it as part of any refueling options. Pub. Ex. 3, p. 9. Further, when Vectren South issued its RFP, it did so for 600-800 MW of dispatchable power, precluding smaller units that might have combined with refurbishment of other Vectren South units. Tr. B-25 - B-26. Vectren South did not fully model the conversion of one of the A.B. Brown units in its rebuttal testimony. Tr. E-45 – E-46.

On cross-examination, Vectren South witness Mr. Swiz estimated that the value of the stranded assets at the A.B. Brown unit alone will equal $220 million and that the system-wide total will be $270 million. While Vectren South argues that the CCGT option is the lowest cost, we find for the many reasons stated throughout this Order, including Vectren South's failure to sufficiently consider the refurbishment and continued operation of its existing facilities, we are not able to verify this claim. Through the lens of minimizing risk and providing future flexibility the refurbishment option would seem to provide a potential bridge to the future, providing system capacity value that was not sufficiently evaluated. This conservative solution and risk avoidance strategy stands in stark contrast to proposed CCGT. Vectren South plans to submit a new IRP in 2019. We instruct Vectren South to closely consider our analysis in this Order and the Director's Report on the 2016 IRP of the flaws in their modeling for the 2016 IRP and the 2017 IRP Update and to present a more thorough

analysis that fully evaluates all possible options for continuing to provide reliable, efficient, and economical electric service.

(b) Conservation and Load Management. The evidence demonstrates that Vectren South has evaluated the CCGT against other reasonable generation alternatives, and included demand side management and energy efficiency ("DSM/EE") levels consistent with the targets approved in Cause No. 44927. Vectren South's modeling concludes that, even when the cost of energy efficiency has been significantly lowered, the CCGT is still the least cost reliable resource alternative to meet Vectren South's customers' future energy resource needs.

The Joint Intervenors criticize the assumptions used by Vectren South to model the cost of DSM/EE, arguing that the assumptions used by Vectren South were too high resulting in a higher cost of DSM/EE. Ms. Harris stated in her rebuttal that for purposes of this proceeding, Vectren South opted only to update its growth factors in its revised cost analysis in order to show the impact lower DSM/EE costs would have on the energy resources selected in its IRP. Ms. Harris explained that limiting the updates to the growth factors preserved the integrity of Vectren South's 2016 IRP. Petitioner's Exhibit No. 8-R, p. 3. We find that while some of the cost assumptions used by Vectren South could have been updated, on the whole it does not render Vectren South's analysis of DSM/EE unreasonable.

(c) Cogeneration and Renewable Energy Sources. Vectren South's IRP modeling process considered the potential for cogeneration facilities to serve its customers and adjusted its load forecast to reflect the potential for cogeneration facilities. Petitioner's Exhibit No. 5, Attachment MAR-1, pp. 99-103. Consequently, the potential for customer-owned generation resources, including renewable generation, to reduce Vectren South's load was evaluated as part of the IRP process that concluded the CCGT was necessary as part of least-cost planning. Nonetheless, while Vectren South may have considered renewable energy in the IRP, there is a lack of evidence that Vectren South made a serious effort to determine the price and availability of renewables. In addition, the economics of customer-scale renewable and cogeneration facilities appears likely to continue to improve and we anticipate that additional well-developed efforts to understand their customers' interest would serve to provide clarity to the lens of risk avoidance by minimizing the potential for unexpected demand side efforts. Therefore, we would expect Vectren South to ensure an enhanced consideration of renewable energy and customer-generator opportunities in future IRPs.

(3) Ind. Code § 8-1-8.5-5. A certificate may be granted only if the Commission makes the followings findings:

(a) Best estimate of construction, purchase, or lease costs based on the evidence of record. The cost estimates for Vectren South's proposed CCGT were developed and presented by witness Diane Fischer. Black & Veatch developed a design basis and conceptual design and thereafter developed a cost estimate. Several conceptual designs were first developed. From that, ten plant alternatives for purposes of estimating costs were identified. This was later narrowed to seven alternatives for which detailed costs were developed. Competitive bids were obtained for the equipment and materials. Based upon Black & Veatch's experience as an engineering, procurement and construction ("EPC") contractor, Black & Veatch was able to estimate indirect costs, contingency, overhead, and profit for the EPC contractor. Bids were also received for construction. Ultimately, Ms. Fischer testified that the cost estimate for the proposed CCGT had been refined to +/- 10%. The total estimated project cost (excluding owner's costs) was $582,000,000. The owner's

costs were then provided by witness Games, including insurance, contingency, study, and AFUDC. The total cost estimate was $781,000,000.

(b) Consistency of the CCGT with Vectren South's Utility-Specific IRP and the Statewide Analysis. Ind. Code § 8-1-8.5-5(b)(2)(A) directs the Commission to determine whether Vectren South's proposed construction of a new CCGT will be consistent with the Commission's 2018 Statewide Analysis. The final version of that report was issued after the parties' pre-filing deadline, but before the evidentiary hearing and was admitted into evidence as Pet. Admin. Not. Ex. 2. Included in that report is a synopsis of information taken from the most recent IRP projects of Indiana utilities, including Vectren South.

In Appendix 12 of the Statewide Analysis, the concept of Resource Diversity is explained:

> In an electric system, resource diversity may be characterized as utilizing multiple resource types to meet demand. A more diversified system is intuitively expected to have increased flexibility and adaptability to: 1) mitigate risk associated with equipment design issues or common modes of failure in similar resource types, 2) address fuel price volatility, and 3) reliably mitigate instabilities caused by weather and other unforeseen system shocks. In this way, resource diversity can be considered a system-wide tool to ensure a stable and reliable supply of electricity. Resource diversity itself, however, is not a measure of reliability. Relying too heavily on any one fuel type may create a fuel security or resilience issue because the level of resource mix diversity does not correlate directly with a resource portfolio's ability to provide sufficient generator reliability attributes.

Vectren South's proposal to concentrate its base load capacity from five different generating units located at three different sites down to just three generating units (one of them constituting 70% of Vectren South's baseload capacity) located at two sites appears to be contrary to the concept of resource diversity.

On page 5 of the 2018 Statewide Analysis it says:

> A key consideration in long-term resource planning is the need to retain maximum flexibility in utility resource decisions to minimize risks. An IRP developed by a utility should be regarded as illustrative and not a commitment for the utility to undertake.

In explaining the importance of sound long-range planning on page 56 of the 2018 Statewide Analysis, it says, "[t]he credibility of the analysis is critical to the efforts of Indiana utilities to maintain as many options as possible, which includes off ramps, to react quickly to changing circumstances and make appropriate changes in the resources." However, we find nothing in Vectren South's evidence convinces us that its proposal provides any off ramps that would allow Vectren South to react to changing circumstances and make appropriate changes in resources. To the contrary, Vectren South's proposal seems to close most off ramps for the foreseeable future.

The parties offered diametrically opposed views on the modeling offered to support the CPCN, with Vectren South pointing to its CCGT conclusion as consistent with its IRP. But that conclusion is but one part of the analysis. We have criticized utilities in the past for modeling infirmities and even penalized a utility for analysis we found lacking. In IPL's MATS case, we ordered a $10 million credit to customers to "send[] an appropriate message" to the utility. *Indianapolis Pwr. & Light Co.*, Cause No. 44242, 2013 WL 4479081 *38, 307 P.U.R.4th 311, Order p. 36 (IURC Aug. 14, 2013). We found IPL's cost/benefit study "disappointing" and noted our own "responsibility to insure that the regulatory process involves the presentation of the best evidence possible, given the facts and circumstances of a particular case." *Id.* at 35.

At the outset, Mr. Games testified that Vectren South sent a request for information ("RFI") to original equipment manufacturers ("OEM") for CCGT pricing information before Vectren South's 2016 IRP. Tr. E-89 – E-91. Mr. Chapman stated that under any of the IRP models, the CCGT is the least expensive. Tr. A-27 - A-28.

Dr. Boerger testified that Vectren South did not consider other viable options such as refueling and smaller combinations of generation assets to meet its needs, Pub. Ex. 3, p. 1 – p. 2, which would be more prudent for a small utility like Vectren South. Pub. Ex. 3, p. 5. Vectren South excluded possible options such as maintaining Culley 2, Pub. Ex. 3, pp. 11-12, and did not allow the refueling of the A.B. Brown units to be included in any of its model runs. *Id.* Vectren South kept a smaller, 440 MW CCGT from being combined with a refueled A.B. Brown unit. Pub. Ex. 3, p. 13. Mr. Games admitted that Vectren "never [ran] a risk analysis of portfolios including a 1 X 1 CCGT instead of a 2 X 1[.]" Tr. E-50. Vectren South also did not allow for proposals of joint projects to be built at it's A.B. Brown site, which would eliminate the potential for congestion problems Vectren South identified as a problem in its RFP responses. Vectren South's Strategist model limited the amount of capacity purchases that a given portfolio could make. Tr. D-73. This had the effect of automatically screening out PPAs that could have been combined with other resources to meet Vectren South's capacity needs. The Director's Report on Vectren South's 2016 IRP noted that Vectren South failed to model a wide range of gas prices, making the "range of fuel price projections… unduly limited[,]" Tr. D-85, and Vectren South's re-run of gas costs did not model higher prices in a wide enough range. Tr. D-86. As noted by Mr. Alvarez, Vectren South's model retired the BAGS 2 unit in 2024 without evidence of any engineering reason to do so. Pub. Ex. 2, pp. 13-14.

Dr. Boerger also found that Vectren South modeled the cost of its proposed CCGT to be $200 million less than the cost of the project presented in the testimony of Vectren South witness Games. Pub. Ex. 3, p. 2. The consequence of excluding $200 million in Vectren South's NPV calculation had the effect of making the CCGT option look more favorable. Pub. Ex. 3, p. 14. Without adding the $200 million back into the model runs, Vectren South's analysis is skewed. Pub. Ex. 3, p. 18 – p. 19. Mr. Games admitted that his testimony about the estimates was confusing, stating "[w]e started off with 2017 dollars, and those were -- then overheads were added, anticipated profit with the EPC, contingency for EPC, and escalation was added to get to the 582 million." Tr. E-15 – E-16. Mr. Lind took issue with Dr. Boerger's analysis, but admitted that Vectren South did not include $130 million in owner's costs when it compared its self-built CCGT to other options offered in the RFP and otherwise. Tr. A-36 – A-38; Tr. D-7 – D-8. When questioned why BMC did not use the $781 million figure, Mr. Lind stated that the $630 million estimate used for modeling was a +/- 50% estimate; the $781 million had a more certain +/- 10% range of accuracy. Tr. A-35; Tr. C-61 - C-62, C-74. BMC's projected cost of $580 - $650 million was used to weigh the economics of potential projects. Tr. A-

36 – A-38. And Vectren South witness Mr. Vicinus ran his "low regulatory" model using the $630 million estimate. Tr. D-98.

In response to the OUCC's criticism of its modeling, Vectren South's rebuttal included a new model run that refueled one of the A.B. Brown units, and added 200 MW of solar. Tr. D-12 – D-13. Vectren South used this rebuttal modeling to try to reinforce its original request for a 850 MW CCGT. Both Mr. Lind and Mr. Games acknowledged, however, that the addition of 200 MW of solar was not the best choice to meet MISO's PRM, because MISO would only give Vectren 100 MW of credit for the 200 MW of solar. Tr. E-15. The revised model also did not take into account the fact that solar costs between $1,200 - $1,800 per MW, Tr. D-16 – D-17, and Vectren South did not model any storage to counter the inherent intermittency of solar resources. Tr. D-14.

While we find Vectren South's request is "consistent" with its 2016 IRP, the subsequent modeling for this case effectively screened out multiple less-expensive alternatives. Vectren South did not allow its models to choose refueling or smaller units in combination. While Vectren South's rebuttal modeling runs included refueling of the A.B. Brown units in various configurations, the rebuttal modeling was not used to make Vectren South's decision of what generation form to choose. Tr. D-14. We view the rebuttal modeling as an after-thought used to buttress Vectren South's initial request.

Vectren South had sufficient time to conduct its analysis in a way more open to smaller-scale options that would correct the modeling deficiencies that have been identified. It seems straight-forward to suggest that smaller-scale options, especially for a relatively small electric utility, serve to minimize the risk should a challenge arise at any one option. As noted above, minimizing supply side long-term investment risk in an environment of rapid technological innovation is an attractive characteristic in a utility resource proposal. Vectren South should use its scheduled 2019 IRP process to address problems in its modeling, incorporate more options for partnering with other entities and competitive inquiries into smaller-scale options that can be acted upon swiftly to meet the end-of-2023 date upon which additional capacity may be needed.

(c) Public Convenience and Necessity. Ind. Code § 8-1-8.5-5(b)(2) requires that we find that public convenience and necessity requires or will require the proposed CCGT. Such consideration of the public interest is not only a statutory requirement at the outset but would become a continuing obligation should the Commission grant a CPCN. Ind. Code § 8-1-8.5-5.5 provides that if, after granting a CPCN for construction of a new generator, "the commission finds that completion of the facility under construction is no longer in the public interest, the commission may modify or revoke the certificate."

"[P]ublic interest may be taken to encompass a wide range of considerations, from environmental, health, and safety concerns, to the financial concerns of employers, employees, and ratepayers." *General Motors Corp. v. Indianapolis Power & Light Co.*, 654 N.E.2d 752, 762 (Ind. Ct. App., 1995). In *General Motors*, the court approved the Commission's consideration of the impact on employment in the coal industry in its public interest determination. *Id.*

The parties dispute whether Vectren South accurately and adequately evaluated risk in its analysis of alternative portfolios and selection of the proposed CCGT. As noted earlier, under Ind. Code § 8-1-8.5-4, we are required to take into account other methods for providing reliable, efficient,

and economical service, and we find utility risk analyses play an important role in comparing alternative portfolios.

Joint Intervenors argued that Vectren South's risk analysis is inadequate for multiple reasons. Joint Intervenors note that the risk analysis has not been updated since the 2016 IRP, despite Vectren South having updated inputs available for several inputs, including the estimated cost of its preferred build, and adequate time to re-run the model. Joint Intervenors complain that Vectren South ignored known material risks in a manner that biased results in favor of its preferred portfolio, including taking a one-sided view of capacity purchase and market purchase risks and failing to consider the potential for future methane regulations. Joint Intervenors further argue that Vectren South arbitrarily scored several metrics and designed others to conceal rather than measure obvious risks of the preferred portfolio.

We find merit in several of Joint Intervenor's critiques and are further concerned that Vectren South has not fully responded to critiques in the Final Director's Report on the 2016 IRPs. We agree that Vectren South had adequate time and opportunity to update its risk analysis modeling prior to this filing, and that it has sufficient time to do so now before moving forward. Vectren South updated inputs in its possession for multiple factors, including: solar capital costs; variable production costs and revenue requirement assumptions for existing units; forecasted cost for wholesale market capacity and energy; delivered fuel prices for gas and coal; and costs associated with new energy efficiency programs. Pet. Ex. 6 at 9-10. Vectren South also had a higher capital cost estimate for its preferred build. We know Vectren South had time to use these inputs to re-run the model because (a) it did just that with some of its Strategist modeling and (b) Mr. Vicinus testified that it would have taken just three months to re-run the risk analysis modeling. Tr. p. D-66. Mr. Vicinus opined that updated risk modeling would not change the result, but we are skeptical given the number and import of the updated inputs and the significance of the proposed portfolio changes. *See Indianapolis Pwr. & Light,* Cause No. 44339, 2014 WL 2091348, Order p. 27 (IURC May 14, 2014) ("[W]e believe that IPL could have reasonably updated the [model] given the extent of changes in data inputs and assumptions and provided a more robust analysis."). Before proposing a portfolio change of this magnitude, Vectren South should have taken the three months necessary to update its risk analysis modeling. Updated risk modeling may not be necessary in all cases, but it is warranted here given the size and cost of the proposed CCGT.

We are further concerned that Vectren South appears not to have accounted for material risks associated with its preferred portfolio. As we have previously stated, "it is appropriate that modeling take into consideration reasonable risks and unknowns." *Indianapolis Pwr. & Light Co.*, Cause No. 44794, 2017 WL 1632316, Order p. 28 (IURC Apr. 26, 2017). Joint Intervenors point out that Vectren South's risk analysis took a one-sided view of capacity purchase and market purchase risks. *See* JI Ex. 2 at 43; Vicinus Rebuttal. Vectren South offered no rebuttal explaining its one-sided view of market risk, which assumed surplus capacity and generation offers only benefits to ratepayers. JI Ex. 2 at 20-21. That view of market purchases is only true when market prices and/or load are high. JI Ex. 2 at 21. Further, Vectren South's Docket Entry response of October 5, 2018, presents portfolio results that suggest the material weight at which opportunity sales influences the analysis.[8] Heavy dependence on market revenues to support a regulated investment choice is a speculative influence that we find must be materially discounted to limit the risk of customers being saddled with

[8] The submitted table indicates that the advantage of the Preferred Portfolio in comparison to (1) BAU to Gas Conversion escalates from 1.3% to 3.5% when the opportunity sales sharing moves from 50% to 100%.

uneconomic options should such speculation unfold differently than forecasted. A metric biased in favor of portfolios with surplus generation is speculation we decline to embrace.

Vectren South's own witnesses and others acknowledged risks related to relying on gas generation, but Vectren South only considered carbon dioxide emission reductions when it evaluated environmental risk. We agree that was too narrow an approach to environmental risk and one that biased the analysis in favor of gas-fired generation.

The Commission appreciates the metrics developed and used by Vectren South in the 2016 IRP, but we agree with the Joint Intervenors that the use of these particular metrics also obscured critical characteristics of the preferred portfolio. One of Vectren South's IRP objectives was to develop a plan with flexibility to adapt to market conditions and technological change to minimize risks to shareholders and customers. Specific metrics to measure resource portfolio balance and flexibility included concentration on one technology, the number of technologies and having resources remote from Vectren South's load. A critical piece of information these metrics overlook is that the acquisition of an 850 MW resource must be evaluated relative to the load to be served. Vectren South's 2016 IRP Base peak load forecast is for the summer peak to increase from 1,109 MW in 2019 to 1,198 MW in 2036. The acquisition of an 850 MW generation facility represents approximately 77 percent of the 2019 peak load and just under 71 percent of the summer peak load for 2036. We are hard pressed to see how reliance on one facility for so much of the Vectren South system requirements is consistent with maintaining flexibility to respond to changing market conditions and technological change.

Therefore, we conclude that Vectren South's risk analysis does not adequately consider the relative risk of other methods for providing reliable, efficient, and economical electric service. The proposed large scale single resource investment for a utility of Vectren South's size does not present an outcome which reasonably minimizes the potential risk that customers could sometime in the future be saddled with an uneconomic investment or serve to foster utility and customer flexibility in an environment of rapid technological innovation. As a result, we find that Vectren South has not demonstrated through the evidence of record that the public convenience and necessity require the building of an 850 MW CCGT. Therefore, Vectren South's request for a CPCN to construct a 850 MW CCGT is denied.

B. Vectren South's Request for a CPCN for Culley compliance projects and related relief. Vectren South's preferred portfolio also includes the construction of various environmental projects that Vectren South contends are needed so that Culley Unit 3 can continue to operate beyond 2023. Vectren South's petition seeks relief for these projects under Ind. Code ch. 8-1-8.4 as "federally mandated" projects.

i. Ind. Code ch. § 8-1-8.4 ("Chapter 8.4").

(1) Federally Mandated Requirements (Ind. Code §§ 8-1-8.4-5 and 8-1-8.4-6(b)(1)(A) and 8-1-8.4-7(b)(3)). Ind. Code § 8-1-8.4-5 defines a federally mandated requirement to include "a requirement that the commission determines is imposed on an energy utility by the federal government in connection with any of the following: (2) The federal Water Pollution Control Act (33 U.S.C. 1251 *et seq.*)" and also includes "(7) Any other law, order, or regulation administered or issued by the United States Environmental Protection Agency, the United States

Department of Transportation, the Federal Energy Regulatory Commission, or the United States Department of Energy."

The description of the Culley 3 Compliance Projects was set forth in the direct testimonies of Ms. Fischer and Ms. Retherford. The Culley 3 Compliance Projects consist of (1) conversion of the current wet bottom ash collection system to a dry handling bottom ash system; (2) installation of a spray dryer evaporator system; and (3) the closure of the Culley West ash pond and construction of a new lined process water and storm water retention pond in its place. This new retention pond will be constructed on the location of the existing ash pond due to space limitations. No party disputed that the dry handling bottom ash conversion or spray dryer evaporator system qualify as compliance projects to meet federally mandated requirements. The OUCC challenged whether the closure of the existing pond qualified for relief but did not contend that it was not federally mandated. For the reasons described below, we find that these projects all constitute compliance projects to meet federally mandated requirements as those terms are defined in Ind. Code §§ 8-1-8.4-2 and -5.

Vectren South witness Retherford testified that the dry handling bottom ash system is required to comply with the ELG Rule, which was promulgated under the federal Water Pollution Control Act. Petitioner's Exhibit No. 9, p. 11. The ELG rule prohibits further wet handling of fly and bottom ash. This system will enable ash from Culley Unit 3 to be disposed of in a landfill, hauled back to a surface mine in accordance with applicable surface mining regulation or recycled rather than being washed into the ash pond as part of a water discharge.

Ms. Retherford further explained that the spray dryer evaporator system was necessary to ensure compliance with ELG-imposed limits on FGD wastewater discharge. She noted that this system functions effectively as a ZLD system and enables Vectren South to utilize the alternative ELG-imposed compliance date of December 31, 2023, and to meet future more stringent ELG wastewater discharge limits.

Ms. Retherford testified that construction of a new, lined process and storm water retention pond is required to comply with the ELG Rule. As we have already noted, projects necessary to comply with the ELG Rule, promulgated pursuant to the federal Water Pollution Control Act (33 U.S.C. 1251 *et seq.*), constitute a federally mandated requirement. The only dispute, raised by OUCC witness Aguilar, pertains to Vectren South's plans to close the existing Culley West pond so that the new lined pond can be built at the site. Witness Retherford testified that there are two reasons the Culley West pond is closing: (1) the pond was taken out of service prior to the 2015 deadline and the CCR rule requires that it be closed by 2020; and (2) the current space limitations require that the new stormwater retention and process water pond be constructed on the current location. Thus, there is no dispute that costs associated with the construction of the new lined pond are incurred pursuant to a federally mandated requirement. The dispute is whether the costs to close the Culley West pond so that the new pond can be built on top of that location, also qualify as federally mandated costs.

The OUCC identifies three reasons closure costs for the Culley West pond should not be considered federally mandated costs. First, OUCC witness Aguilar contends that Vectren South has been collecting depreciation and asset retirement costs in base rates, which include the closure of ash ponds. Public's Exhibit No. 1, p. 28. However, Vectren South witness Retherford responded that finalization of the CCR rule on April 17, 2015 imposed more stringent requirements to close the ash pond. The CCR rule imposed an obligation to dewater, cap and/or remove ponded ash. Petitioner's Exhibit No. 9-R, pp. 24-25.

On rebuttal, Mr. Swiz stated Vectren South's existing depreciation rates include an estimated level of cost of removal that was designed well before the implementation of requirements to close the ponds in accordance with the environmental regulations described by Ms. Retherford. The assumed removal costs in the demolition study provided in Cause No. 43839 (Vectren South's most recent general rate case), estimated $1.1 million to close both of the Culley Ash Ponds based on cost of backfill, grading and seeding. By comparison, the estimate for closure of one ash pond in this proceeding is $19.969 million. Petitioner's Exhibit No. 13-R, pp. 6-7; Petitioner's Administrative Notice 1.

Consequently, we find that costs associated with CCR closure have not been included in Vectren South's depreciation rates, which were last updated prior to finalization of the CCR Rule.

Second, the OUCC contends that other utilities are not tracking pond closure costs as Federally-Mandated CCR Projects. Public's Exhibit No. 1, p. 28. Vectren South witness Swiz noted that no utility had proposed such recovery yet but that one utility specifically indicated that it would present closure related activities as recoverable under the Federal Mandate Statute. Petitioner's Exhibit No. 13-R, pp. 6-7. Mr. Swiz explained that Duke, IPL and NIPSCO did not ask for recovery of their pond closure costs in the proceedings Ms. Aguilar cited, and in fact the order in Cause No. 44765 specifically notes that Duke anticipates presenting closure related activities of existing surface impoundments and their associated costs in a future proceeding. Petitioner's Exhibit No. 13-R, p. 6, citing *Duke Energy Indiana*, Cause No. 44765, at *7 (IURC May 24, 2017). Each of the cases Ms. Aguilar cited were settled cases containing non-precedential language. Nevertheless, Mr. Swiz pointed out that the NIPSCO Order in Cause No. 44872, suggests that the OUCC agreed that closure costs can be recovered as federally mandated costs. Petitioner's Exhibit No. 13-R, p. 7.

Third, the OUCC contends that Vectren South should have presented alternative suitable locations to the West Pond for consideration. However, Ms. Retherford testified that the location was chosen because there was limited space at the Culley generating station. In other words, there was not an alternate location to explore. The statutory requirement to consider options does not require a utility to present alternatives that are not practical or feasible. Accordingly, we find the Culley 3 Compliance Projects are all federally mandated requirements and that Vectren South described them in its application.

(2) Energy utilities seeking recovery of Federally Mandated Costs must establish that the costs are incurred in connection with a compliance project, including capital, operating, maintenance, depreciation, tax or financing costs and describe the costs to be recovered. Ind. Code §§ 8-1-8.4-4 and -6(b)(1)(B). We have already found that the Culley 3 Compliance Projects constitute projects required by federally mandated requirements. Consequently, the costs associated with these projects constitute Federally Mandated Costs. These costs will consist of capital, operating, maintenance, depreciation, tax and financing costs. Vectren South identified the estimated costs to be recovered as Federally Mandated Costs. Costs associated with the dry handling bottom ash handling system and spray dryer evaporator system were identified by Vectren South witness Fischer. Petitioner's Exhibit No. 6, pp. 16-18, 26-28. Costs associated with the construction of a new lined process water and storm water retention pond were identified in Ms. Retherford's testimony. Petitioner's Exhibit No. 9, Attachment AMR-1. No party disputed the cost estimates for the Culley 3 Compliance Projects. Based on the evidence presented, we find that Vectren South has identified

federally mandated costs and reasonably described those costs. Those total costs are $95 million, and they are hereby approved. Petitioner's Exhibit No. 4, p. 26.

(3) Compliance with Federally Mandated Requirements (Ind. Code §§ 8-1-8.4-6(b)(1)(C)) and 8-1-8.4-7(b)(3)). No party disputed that the Culley 3 Compliance Projects will allow Vectren South to comply with ELG and CCR or that ELG and CCR are federally mandated. We previously addressed the OUCC's objections related to appropriateness of recovery. We have already found that the ELGs and CCR Rule are federally mandated requirements within the meaning of Ind. Code §§ 8-1-8.4-5 and 8-1-8.4-6(b)(1)(A) and 8-1-8.4-7(b)(3). Based on the evidence presented, we find that Vectren South's Culley 3 Compliance Projects, will allow the utility to comply with the ELGs and the CCR Rule. Therefore, we find that Vectren South has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(C).

(4) Alternative Plans for Compliance (Ind. Code §§ 8-1-8.4-6(b)(1)(D) and 8-1-8.4-7(b)(3)). Ind. Code § 8-1-8.4-6(b)(1)(D) requires the Commission to examine "[a]lternative plan that demonstrate that the proposed compliance project is reasonable and necessary." Vectren South witness Diane Fischer testified about Black & Veatch's evaluation of the ELG Compliance Program for Culley to identify potential FGD discharge water treatment alternatives and ash transport water alternatives that could be implemented to comply with the ELGs. She sponsored two written reports setting forth Black & Veatch's analyses of the alternatives. Ms. Fischer testified that each of the potential discharge treatment technology alternatives assessed by Black & Veatch were screened for design concept feasibility, capital expense and operating expense.

With respect to FGD discharge water treatment, two main treatment alternatives were considered: (1) FGD treatment and discharge; and (2) zero liquid discharge ("ZLD"). Three technology types were evaluated within these two treatment alternatives: (1) for FGD treatment and discharge, physical/chemical pretreatment with biological treatment technology, (2) for ZLD, spray dryer evaporator technology, and (3) also for ZLD, brine concentrator/crystallizer technology. Ms. Fischer testified that multiple vendors providing such technologies were evaluated. A sensitivity analysis was then performed for each technology and vendor. Ms. Fischer's Discharge Treatment Report also included a cost assessment of all alternatives considered. Petitioner's Exhibit No. 10, p. 7. Ms. Fischer testified that Black & Veatch provided Vectren South with a final overall assessment of each technology and vendor offering based on Black & Veatch's analysis and the following attributes: (1) start-up/ramp up reliability; (2) technology readiness risk; (3) adaptability to sensitivity analysis scenarios; (4) operation and control risk; (5) heat rate impact risk; (6) number of operators; (7) capital and annual O&M costs; (8) susceptibility to future environmental regulations; (9) overall financial stability and credit rating. Black & Veatch ultimately recommended that Vectren move forward to a detailed engineering phase with Stochastic Differential Equation ("SDE") type technology if the maximum FGD wastewater flow rate of between 50 and 80 gpm is achieved through future testing and operations. Ms. Fischer explained the SDE solution ranks the highest among all technologies based on the attributes discussed above and the solution is economically viable and provides a zero discharge solution if the minimum FGD wastewater flow rate of between 50 and 80 gpm is achieved. The conceptual design evaluation indicated the SDE can be feasibly located and tied into the existing equipment at Culley. In addition, Ms. Fischer stated the ZLD solution provides certainty that any future change in EPA regulations would not apply at Culley since there would be no discharge of FGD wastewater.

With respect to ash transport, Ms. Fischer described Black & Veatch's analysis to identify alternative ash transport solutions that could be implemented at Culley to comply with ELG requirements, focused specifically on identifying options for removal and dewatering of bottom ash from the Culley Unit 3 boiler with truck transport and disposal of the dry material at an off-site location. Black & Veatch evaluated two categories of technologies: (1) dry conversion of the bottom ash system and (2) closed loop wet sluicing system. For dry conversion system, Black & Veatch evaluated a submerged chain conveyor under the existing bottom ash hopper. For the closed loop wet sluicing system, Black & Veatch evaluated both a dewatering bunker and a remote submerged chain conveyor. In comparing all technologies, Black & Veatch used the following quality attributes to select the preferred treatment: technical feasibility; total installed cost, O&M cost, estimated additional manpower ("FTE"), estimated footprint, major equipment, advantage, disadvantages and reliability. Ms. Fischer's testimony discussed in detail the advantages and disadvantage of each alternative. Black & Veatch prepared cost estimates for all technologies considered for addressing ash transport water. Black & Veatch ultimately recommended the submerged chain conveyor for Culley 3 compliance with ELG requirements, due to the complexity of design and comparatively higher installed cost of the other alternatives.

The only evidence offered in opposition as being an alternative plan was the OUCC's conclusory statement about possible alternative locations for the new lined pond. As we have previously found, the chosen site was selected because there are no alternative locations.

While the Commission gives significant weight to cost-effective planning and decision making when considering alternatives, the Federal Mandate Statute does not require that a utility demonstrate that the chosen compliance plan is the least cost option. Consistent with the Commission's finding in Indianapolis Power and Light's recent proceeding, Cause No. 44794 (IURC 4/26/2017), p. 30, 2017 Ind. PUC LEXIS 114, *92, (finding "it is important that the Petersburg Station is able to continue to operate on coal and protect customers from potential price volatility in the gas markets"), a reasonable alternative can be, and often is, a solution that includes risk balancing through a diversified portfolio.

Based on the evidence presented, we find that Vectren South considered alternative plans for compliance with the ELGs and the CCR Rule. The evidence shows that the Culley 3 Compliance Projects are reasonable and necessary.

(5) Useful Life of the Facility (Ind. Code §§ 8-1-8.4-6(b)(1)(E) and 8-1-8.4-7(b)(3)). Mr. Games testified that the investments in the Culley 3 Compliance Projects will allow for the continued operation of Vectren South's most efficient coal fired unit. Ms. Retherford described the environmental regulations requiring the Culley 3 Compliance Projects in order for Culley Unit 3 to continue operating. Ms. Retherford explained how closure of the Culley West pond will extend the useful life of Culley 3, because closure of the Culley West pond is necessary to provide a suitable location to construct a new pond that can continue to take non-CCR process water discharged from Culley Unit 3 and plant stormwater (i.e. surface water) which flows into the West Pond. Without this new lined process and stormwater pond, continued operation consistent with applicable regulations would be impossible after the Culley East pond commences closure.

No party disputes that issuance of a CPCN for the Culley 3 Compliance Projects will extend the useful life of Vectren South's Culley 3 unit or that Culley 3 would be required to retire in the near future if the Culley 3 Compliance Projects are not completed.

Based on the evidence presented, we find that Vectren South has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(E).

(6) Conclusion. We find that the Culley 3 Compliance Projects will allow Vectren South to comply directly or indirectly with one or more federally mandated requirements and that public convenience and necessity will be served by the Culley 3 Compliance Projects.

ii. Accounting and Ratemaking Issues Associated with Culley Compliance Projects. Ind. Code § 8-1-8.4-7(c) states:

> If the commission approves under subsection (b) a proposed compliance project and the projected federally mandated costs associated with the proposed compliance project, the following apply:
> (1) Eighty percent (80%) of the approved federally mandated costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism that allows the timely recovery of the approved federally mandated costs. The Commission shall adjust the energy utility's authorized net operating income to reflect any approved earnings for purposes of IC 8-1-2-42(d)(3)and IC 8-1-2-42(g)(3).
> (2) Twenty percent (20%) of the approved federally mandated costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, based on the overall cost of capital most recently approved by the commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the commission.
> (3) Actual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent (25%) shall require specific justification by the energy utility and specific approval by the commission before being authorized in the next general rate case filed by the energy utility with the commission.

(1) Accounting and Ratemaking Treatment for ECA. Vectren South requests authority to implement a new annual rate adjustment mechanism ("ECA") pursuant to Ind. Code § 8-1-8.4-7 for the timely and periodic recovery of 80% of the federally mandated costs. Vectren South also requests approval of proposed changes to its electric service tariff relating to the proposed ECA mechanism, including the proposed Appendix E. Ind. Code §8-1-8.4-8 provides that an energy utility may, in a timely manner, recover 80% of all federally mandated costs through a periodic rate adjustment mechanism. Ind. Code §§ 8-1-8.4-4 and 8-1-8.4-7 provide that such costs include capital, AFUDC, O&M, depreciation, tax, and financing costs.

Vectren South witness Swiz described how the eligible costs associated with the Culley 3 Compliance Projects will be incorporated into the proposed ECA mechanism. He testified Vectren South will prepare in each annual filing a revenue requirement calculation accumulating all eligible costs incurred through December 31 of the previous calendar year. To provide for timely recovery, Mr. Swiz testified the proposed ECA will project an annualized level of expense related to the approved projects for the 12-month effective period. Mr. Swiz stated the annual revenue requirements

will capture eligible new capital investments (both in service and Construction Work in Progress) related to the Culley 3 Compliance Projects, multiplied by the applicable rate of return, with depreciation, O&M and property tax expenses associated with the projects, and recovery of the regulatory assets recorded through interim deferral of depreciation expense, plan development expense, and PISCC, added to the resulting total. The revenue requirement for those projects will be the basis for the recovery of 80% of the eligible revenue requirement amounts in each annual ECA filing.

Mr. Swiz also described Vectren South's proposal to defer and subsequently recover depreciation expense as well as costs associated with development of the Culley 3 Compliance Projects through the ECA. The cumulative deferred balances of the regulatory assets recorded through interim deferral of such depreciation expenses would be amortized over the remaining life of the assets (20 years) and the amortization amount would be included in the ECA revenue requirements. Mr. Swiz stated the costs of development of the projects would be included for recovery within the ECA, with the balance amortized over a period of three years.

Vectren South proposes the pre-tax return on the new capital investment will be calculated by multiplying the pre-tax rate of return, based on the weighted average cost of capital ("WACC"), by total new capital investment related to the approved projects. Mr. Swiz testified Vectren South proposes to use a WACC in the ECA based upon the most recent approved WACC within Vectren South's TDSIC mechanism under Cause No. 44910, which is based on a return on equity ("ROE") of 10.4% as approved in Cause Nos. 43111 and 43839, Vectren South's two most recent base rate cases. Mr. Swiz stated the equity component of the rate used in the ECA revenue requirement calculation will be grossed up for recovery of income taxes, both state and federal, at then current rates.

Mr. Swiz testified that approved recoveries within each ECA filing will be calculated by taking the billing determinants by month multiplied by the applicable rates and charges for the ECA period. Any under recoveries resulting from instances in which ECA rates and charges are not in place for a full month will be recovered as an under-recovery variance in a subsequent ECA proceeding. Vectren South proposes to allocate ECA costs pursuant to the four-coincident peak allocation percentages for Vectren South utilized in its Cause No. 43406 RCRA15 and 43405 DSMA15 rate mechanisms.

With respect to the treatment of operating income, Mr. Swiz testified Vectren South will adjust its statutory earnings test under Ind. Code § 8-1-2-42(d)(3) to include the incremental earnings from approved ECA filings.

Mr. Swiz testified Vectren South proposes to file its ECA petitions and cases in chief annually, on May 1 of each year, with new ECA rates and charges becoming effective August 1 of each year. Each filing will be based on capital investments and expenses through the twelve months ended December of the prior calendar year. Variances will be reconciled in each ECA filing and recovered over the subsequent 12 month rate effective period. Vectren South seeks approval of its proposed Sheet No. 69, Appendix E, Environmental Cost Adjustment. Additional changes to Vectren South's rate schedules in its tariff are needed to reflect that the ECA will be applied monthly.

Industrial Group witness Gorman recommended that the ELG costs associated with the Culley 3 Compliance Projects be recovered within a base rate proceeding and not through the proposed ECA. He cited Vectren South's overall rate of return and stated Vectren South's costs have declined since

the last base rate case. He also suggested that Vectren South should be permitted to recover a return on investment of no more than 9.8%.

Mr. Swiz explained on rebuttal that under the statutory test under Ind. Code § 8-1-2-42(d) and -42.3, performed in Vectren South's most recent FAC proceedings as of the time his rebuttal testimony was filed (Cause No. 38708 FAC 120), Vectren South's comprehensive earnings compared to authorized levels, including both changes in expenses and revenues, show that Vectren South is currently under-earning by approximately $6.5 million of net operating income and has been under-earning since February 2017. Mr. Swiz explained that depreciation and operating expense are driving much of these results, and Mr. Gorman does not capture those expenses in his calculation.

Eligibility for recovery through Ind. Code ch. 8-1-8.4 is not contingent on whether other costs have declined to offset the new federally mandated costs. Once we have made the required findings, 80% of the federally mandated costs "shall be recovered by the energy utility through a periodic retail rate adjustment mechanism." Ind. Code § 8-1-8.4-7(c)(1). In any event, we find that Mr. Swiz has adequately explained why Mr. Gorman's position is incorrect.

Mr. Swiz testified that pursuant to Ind. Code § 8-1-8.4-7, Vectren South seeks ratemaking treatment for 80% of the costs associated with the Culley 3 Compliance Projects through its proposed ECA mechanism. Specifically, Vectren South seeks timely recovery of all federally mandated costs associated with the Culley 3 Compliance Projects, including capital costs, AFUDC, post-in-service carrying cost charges ("PISCC"), O&M, depreciation expense, property tax expense, and other taxes, with 80% recovered through the ECA and the balance deferred for recovery in Vectren South's next rate case.

Vectren South proposes to implement construction work in progress ("CWIP") ratemaking treatment related to the recovery of financing costs incurred during construction of the Culley 3 Compliance Projects. In connection with CWIP ratemaking treatment, Vectren South will remove from the AFUDC-eligible balance the amount of investment included for recovery in the ECA, so that only the amount of the Culley 3 Compliance Projects investment not currently being recovered in the ECA would be eligible for AFUDC.

Mr. Swiz testified that Vectren South proposes to accrue post-in-service carrying charges on all eligible new capital investment from the date it is placed in service until the date it is included in rates. He explained the PISCC balances will be multiplied by the pre-tax rate of return within the ECA revenue requirement, at the WACC rate described herein. Unlike other utilities who have been granted such authority, Vectren South is not seeking to accrue and subsequently recover in the next base rate case PISCC on the 20% deferred balance discussed below.

OUCC witness Aguilar opposed Vectren South's request to recover pond closure costs for the Culley 3 Compliance Projects as part of the ECA because the OUCC's position is that Vectren South is already collecting pond closure costs within its depreciation rates. Ms. Aguilar also testified that neither Duke, IPL, nor NIPSCO are tracking pond closure costs. We have already addressed these positions and rejected them.

Based on the evidence presented, we find that the proposed ECA mechanism should allow for the timely and periodic recovery of 80% of Vectren South's approved federally mandated costs. We further find that Vectren South's request for approval to adjust its authorized net operating income to

reflect an approved earnings associated with the Culley 3 Compliance Project for purposes of Ind. Code §§ 8-1-2-42(d)(3) and 8-1-2-42(g)(3) is consistent with Ind. Code § 8-1-8.4-7(c)(1).

Vectren South is authorized to defer (until captured within the ECA mechanism) and recover 80% of the approved federally mandated costs incurred in connection with the Culley 3 Compliance Projects through the approved ECA Mechanism pursuant to Ind. Code § 8-1-8.4-7, including capital, O&M, depreciation, taxes, financing, and carrying costs based on the current overall WACC and AFUDC. Vectren South is authorized to utilize CWIP ratemaking treatment for the Culley 3 Compliance Projects through the proposed ECA mechanism. Vectren South is authorized to defer post-in service costs of the Culley 3 Compliance Projects, including carrying costs based on the current overall WACC, depreciation, taxes and operating and maintenance expenses on an interim basis until such costs are recognized for ratemaking purposes through Vectren South's ECA mechanism or otherwise included for recovery in Vectren South's base rates in its next general rate case. Vectren South is authorized to defer and recover through the ECA mechanism 80% of its federally mandated costs, including but not limited to federally mandated costs incurred prior to and after approval of a final order in this proceeding to the extent that such costs are reasonable and consistent with the scope of the Culley 3 Compliance Projects described in Vectren South's evidence. Vectren South's proposed cost allocation factors are also approved.

(2) Accounting and Ratemaking Treatment for Deferred Costs. Indiana Code § 8-1-8.4-8 provides that 20% of the approved federally mandated costs, including depreciation, AFUDC, and PISCC, based on the overall cost of capital most recently approved by the Commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the Commission. Vectren South proposes to defer as a regulatory asset 20% of all federally mandated costs incurred in connection with these projects.

Based on the evidence presented, the Commission finds Vectren South is authorized to defer 20% of the federally mandated costs incurred in connection with the Culley 3 Compliance Projects, and Vectren South may recover the deferred costs in its next general rate case as allowed by Ind. Code § 8-1-8.4-7(c)(2).

(3) Depreciation Treatment. Vectren South proposes to utilize a depreciation rate of 5%, representing a 20-year life on these investments. Mr. Swiz testified the proposed depreciation rate for the investments aligns with the estimated remaining life of Culley Unit 3.

No party opposed Vectren South's proposed depreciation rate for the investments required for the Culley 3 Compliance Projects.

Based on the evidence presented, we find that Vectren South's proposal to depreciate the individual projects included in the Culley 3 Compliance Projects based on a 5% depreciation rate is reasonable and is approved.

C. Recovery of Prior Pollution Control Investments. Our January 28, 2015 and June 22, 2016 Orders in Cause No. 44446 (the "44446 Orders") (1) granted Vectren South a CPCN for A.B. Brown Unit 1 and 2, Culley Unit 3 and Warrick Unit 3 clean coal technology projects and (2) authorized Vectren South to recover federally mandated costs associated with federally mandated requirements at A.B. Brown Units 1 and 2 (collectively the "MATS Projects"). Rather than recovering

the costs of the MATS Projects through a tracking mechanism as authorized by Ind. Code § 8-1-8.4-7, Vectren South sought, and we granted, authority to defer these costs for recovery in a future proceeding. Vectren South now seeks to commence recovery of the MATS Projects' costs through the ECA pursuant to Ind. Code § 8-1-8.4-7.

Vectren South witness Swiz described the proposed recovery through the ECA in more detail. He indicated that Vectren South proposes recovery of the MATS Projects to begin on January 1, 2019 with the approval of ECA rates and charges recovering the specified revenue requirement. In accordance with applicable statutory requirements, Vectren South proposes to recover the 80% of eligible revenue requirements amounts for post-in-service carrying costs, incremental depreciation and property taxes and financing costs that Vectren South incurred to construct the MATS Projects and deferral of the remaining 20% of these costs for subsequent recovery in a base rate case. Vectren South will prepare an annual revenue requirement as part of the ECA to capture eligible capital investments in plant related to the MATS Projects, multiplied by the applicable rate of return, with depreciation, O&M, and property tax expenses associated with the MATS Projects added to the resulting total. To provide for timely recovery, Vectren South's proposed ECA will project an annualized level of expense related to these approved projects for the 12-month effective period.

Depreciation associated with the MATS Projects will be based on the currently approved depreciation rates applicable to the assets, as approved in Vectren South's last electric base rate case (Cause No. 43839). The pre-tax return on the new capital investment will be calculated by multiplying the pre-tax rate of return, based on the WACC, by total new capital investment related to the approved projects. Vectren South proposes to use a WACC in the ECA based upon the most recent approved WACC within Vectren South's TDSIC mechanism, Cause No. 44910. This WACC, approved by the Commission, represents an updated actual capital structure as of the cut-off date of each TDSIC filing, and includes the typical items captured in Vectren South's base rate case capital structure. This rate will be used in the ECA revenue requirement calculation, and the equity component will be grossed up for recovery of income taxes, both state and federal, at then current rates. O&M expense included for recovery in the ECA will reflect an annualized level of expense related to the MATS Projects. This O&M expense represents incremental chemical costs and other expenses associated only with the MATS Projects.

No party objected to Vectren South's proposal to commence recovery of the MATS Projects' costs, currently being deferred, through the ECA. We previously found the MATS Projects costs qualify as federally mandated costs in the 44446 Orders. While Vectren South proposed, and we approved of, deferral of these costs in lieu of the recovery through a periodic retail rate adjustment mechanism, Vectren South now seeks to recover the costs in accordance with Ind. Code § 8-1-8.4-7(c). We find that Vectren South shall be authorized to commence recovery of these MATS Projects' costs pursuant to Ind. Code § 8-1-8.4-7 through the ECA in accordance with the procedures outlined in Mr. Swiz's testimony.

6. Confidentiality. Vectren South filed motions for protection and nondisclosure of confidential and proprietary information on March 20, 2018, August 21, 2018, and September 10, 2018, respectively. In its motions, Vectren South states certain information redacted in the evidence is confidential, proprietary, competitively sensitive, and/or trade secrets. Docket entries were issued on March 29, August 27, and October 4, 2018 finding such information to be preliminarily confidential and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. The confidential information was subsequently submitted under seal. The Commission finds the

information for which Vectren South seeks confidential treatment is confidential trade secret information pursuant to Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3, is exempt from public access and disclosure by Indiana law, and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Vectren South's request for a certificate of public convenience and necessity under Ind. Code ch. 8-1- 8.5 to construct an 850 MW CCGT and all associated relief requested is denied.

2. Vectren South's request for a certificate of public convenience and necessity for the Culley 3 Compliance Projects pursuant to Ind. Code ch. 8-1-8.4 and all associated relief requested is approved.

3. Vectren South's proposed recovery of federally mandated costs approved in connection with Cause No. 44446 through the ECA is approved as described in this Order.

4. Vectren South's proposed ECA, and Vectren South's proposed Sheet No. 69, Appendix E of its tariff to implement such ECA is approved.

5. The Confidential Information submitted under seal in this Cause pursuant to Vectren South's requests for confidential treatment is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall continue to be held as confidential and exempt from public access and disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4.

6. This Order shall be effective on and after the date of its approval.

HUSTON, KREVDA, OBER, AND ZIEGNER CONCUR; FREEMAN ABSENT:

APPROVED: APR 2 4 2019

I hereby certify that the above is a true and correct copy of the Order as approved.

Mary M Becerra

Mary M. Becerra
Secretary of the Commission

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 115
Vectren 2020 IRP

2019/2020

Integrated Resource Plan

VECTREN

A CenterPoint Energy Company

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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.		2019 IRP submitted on June 30, 2020
(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 1.1-8.3
(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.vectren.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.		3.4 Data Requests Summary
(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 Process Description
(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
(2) The utility may hold additional meetings.		3.1 Process Description
(3) The schedule for meetings shall: (A) be determined by the utility; (B) be consistent with its internal IRP development schedule; and		3 Public Participation Process

(C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.		
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 Base Energy And Demand Forecast
(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.		7.3. Alternate Scenarios; Figure 7.8 Vectren Peak Demand Forecast
(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.		6.3 Potential Future Options Modeling Assumptions; Figure 6-5 Tier 1 Cost Summary
(7) The resource screening analysis and resource summary table required by section 7 of this rule.		Figure 11.35 New Construction Alternatives; Figure 6-5 Tier 1 Cost Summary.
(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 Vectren'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		12 Technical Appendix Attachments

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; (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 2019 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.		11.1.4 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;		4.4 Customer Owned Distributed Energy Resources

(B) transmission planning; (C) distribution planning; and (D) load forecasting.		
(19) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.		4.3 Model Framework; 7.1 Resource Model
(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
(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.		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		7.2 Reference Case Scenario

a high probability of expiration or repeal must be eliminated or altered when applicable. (D) Not include future resources, laws, or policies unless: (i) a utility subject to section 2.6 of this rule solicits stakeholder input regarding the inclusion and describes the input received; (ii) future resources have obtained the necessary regulatory approvals; and (iii) future laws and policies have a high probability of being enacted. A 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		4.3 Model Framework; 7.1 Resource Model; 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

(iv) analysis of risk and uncertainty.		
(29) An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (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.		11.3.5 Avoided 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 2019 Vectren Long-Term Electric Energy and Demand Forecast Report; Attachment 4.2 Vectren 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 2019 Vectren 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 2019 Vectren Long-Term Electric Energy and Demand Forecast Report
(8) Justification for the selected forecasting methodology.		12 Technical appendix attachments 4.1 2019 Vectren 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.		7.3 Alternate Scenarios; 12 Technical Appendix Attachments 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report

(10) State and federal energy policies. (11) State and federal environmental policies.		
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 Aurora Input 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;		11.8 Transmission Appendix

(ii) congestion; and (iii) energy costs. (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.		6.3.2.6 Other Innovative Rate Designs
(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 2019 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.		6 Resource Options; 11.2 Environmental Appendix; 12 Technical Appendix Attachments: Attachment 1.2 Vectren Technology Assessment Summary Table; Confidential Attachment 8.2 Aurora Input Model Files

(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. (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.		6.6 Levelized Cost of Energy Resource Screening Analysis
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. 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.		2.5 Portfolio Development; 8 Portfolio Development and Evaluation
(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.		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 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, 11.7.1 Affordability Ranking; 12 Technical Appendix Attachments, Confidential Attachment 8.2 Aurora Input 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 Vectren's IRP Process; 5 MISO Market; 7.2 Reference Case Scenario; 7.3 Alternate Scenarios; 8.2 Evaluation of Portfolio Performance; 9 Preferred Portfolio; Confidential Attachment 8.2 Aurora Input 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; 11.1.4 Advanced metering Infrastructure and Continuous Improvement
(10) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including changes in the following: (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.		8.2 Evaluation of Portfolio Performance; 9 Preferred Portfolio
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
(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

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
BPM	Business Practice Manual
BSER	Best System of Emission Reduction
Btu	British Thermal Unit
BYOT	Bring You Own Thermostat
C&I	Commercial and Industrial
CAC	Citizens Action Coalition
CAGR	Compound Annual Growth Rate
CAPP	Central Appalachian
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Day
CDS	Circulating Dry Scrubber
CHP	Combined Heat and Power
CNP	CenterPoint Energy
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
Comm	Commercial
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
DA-LSFO	Dual-Alkali FGD-Forced Oxidation
DA-LSIO	Dual-Alkali FGD-Inhibited Oxidation
DC	Direct Current
DG	Distributed Generation

List of Acronyms/Abbreviations (Cont.)

DGS	Demand General Service
DLC	Direct Load Control
DPP	Definitive Planning Phase
DR	Demand Response
DSI	Dry Sorbent Injection
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	Equipment Manufactures
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
FDA	Flash Dryer Absorber
FDNS	Fixed Slope Decoupled Newton-Raphson
FERC	Federal Energy Regulatory Commission
FF	Fabric Filter
FGD	Flue Gas Desulfurization
GDP	Gross Domestic Product
GE	General Electric
GHG	Greenhouse Gas
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GIR	Generator Interconnection Requests
GPS	Global Positioning System
GS	General Service
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt Hour
HB	House Bill
H_2SO_4	Sulfuric Acid
HDD	Heating Degree Days
Hg	Mercury
HHV	Higher Heating Value

List of Acronyms/Abbreviations (Cont.)

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	Industrial
IPL	Indianapolis Power and Light Company
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
LGE/KU	Louisville Gas and Electric/Kentucky Utilities
LIB	Lithium-ion Battery
Li-ion	Lithium-ion
LMP	Local Marginal Pricing
LMR	Load Modifying Resources
LMR	Load Management Receivers
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LP	Large Power
LRR	Local Reliability Requirement
LRZ	Local Resource Zone
LSE	Load Serving Entity
LSFO	Limestone FGD – Forced Oxidation
LTCE	Long-term Capacity Expansion
MATS	Mercury and Air Toxics Standards
MEEA	Midwest Energy Efficiency Alliance
MEP	Market Efficiency Project
MILP	Mixed Integer Linear Programming
MISO	Midcontinent Independent System Operator
MISO Tariff	Open Access Transmission, Energy and Operating Reserve Markets Tariff

List of Acronyms/Abbreviations (Cont.)

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
NAEMA	North American Energy Markets Association
NAICS	North American Industry Classification System
NAPP	Northern Appalachia
NDA	Non-Disclose Agreement
NERC	North American Electric Reliability Council
NERC MOD	NERC Modeling, Data and Analysis
NH_3	Ammonia Scrubber
NIPSCO	Northern Indiana Public Service Company
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxide
NOPR	Notice of Proposed Rulemaking
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
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
PIRA	PIRA Energy Group
PJM	Pennsylvania New Jersey Maryland Interconnection LLC
PM	Particulate Matter
PPA	Purchase Power Agreement
PPT	Parts Per Trillion
PRA	Planning Resource Auction

List of Acronyms/Abbreviations (Cont.)

PRB	Powder River Basin
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PSEG	Public Service Electric and Gas
PTC	Production Tax Credit
PTI PSS/E	Power Technologies Incorporated's Power System Simulator Program for Engineers
PV	Photovoltaic
RAN	Resource Availability and Need
Res	Residential
RF	ReliabilityFirst
RFP	Request for Proposals
RGGI	Regional Greenhouse Gas Initiative
RIIA	Renewable Integration Impact Assessment
RIM	Ratepayer Impact Measure
RS	Rate Schedules
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
SDA	Spray Dryer Absorber
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
STD Dev	Standard Deviation
TDSIC	Transmission, Distribution and Storage System Improvement Charge
T&D	Transmission and Distribution
TBtu	One Trillion British Thermal Unit
TRC	Total Resource Cost
UC	Utility Cost
UCAP	Unforced Capacity
UCT	Utility Cost Test
ULRC	Urban Living Research Center
UPC	Use Per Customer
V	Volt

List of Acronyms/Abbreviations (Cont.)

VAR	Volt-Amp Reactance
VER	Variable Energy Resources
VFD	Variable Frequency Drive
VOM	Variable Operation and Maintenance
VVC	Vectren Corporation
WLIO	Wet Lime FGD – Inhibited Oxidation
WN	Weather Normalized
WTE	Waste to Energy

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Executive Summary (Non-Technical Summary)

I. Introduction

Southern Indiana Gas and Electric Company d/b/a Vectren a CenterPoint Energy Company's ("Vectren") 2019/2020 Integrated Resource Plan is submitted in accordance with 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 Vectren's previous 2016 Integrated Resource Plan ("IRP"). The preferred portfolio in Vectren's previous 2016 IRP contemplated replacement of some of Vectren's coal fleet by the end of 2023 with a mix of renewable, energy efficiency and gas resources while retaining other coal resources. To implement this plan, Vectren filed two cases seeking Certificates of Public Convenience and Necessity ("CPCN") to (1) own and operate a 50 MW solar project located on its system (the "Troy Solar Project"), (2) install equipment designed to achieve compliance with environmental regulations in order to continue operation of its 270 MW Culley Unit 3 beyond 2023 and construct a 700-850 MW Combined Cycle Gas Turbine ("CCGT"). The Commission approved issuance of CPCNs authorizing the construction of the Troy Solar Project and Culley Unit 3 compliance projects. The Commission order denying a CPCN for the 700-850 MW CCGT urged Vectren to:

- Focus on outcomes that reasonably minimize the potential risk of an asset becoming uneconomic in an environment of rapid technological innovation;
- Fully consider options that provide a bridge to the future;
- Utilize a request for proposals ("RFP") to determine the price and availability of renewables; and
- Consider resource diversity and alternatives that provide off ramps that would allow Vectren to react to changing circumstances.

Vectren began its 2019/2020 IRP process in April 2019 with the objective of engaging in a generation planning process responsive to the Commission's guidance and seeking input from a variety of stakeholders. As part of its 2019/2020 IRP process, Vectren's evaluation has focused on exploring all new and existing supply-side and demand side resource options to reliably serve Vectren customers over the next 20 years. While the

fundamentals of integrated resource planning were adhered to in developing the 2016 IRP, Vectren has enhanced its process and analysis in several ways. These enhancements include, but are not limited to the following:

- 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 and solar;
- An exhaustive review of reasonable options that leverage existing coal resources;
- increased participation and collaboration from stakeholders on all aspects of the analysis, inputs and resource evaluation criteria, with specific considerations and responses from Vectren;
- An encompassing analysis of wholesale market dynamics that accounts for MISO developments and market trends;
- The use of a more sophisticated IRP modeling tool, Aurora, which provided several benefits (simultaneous evaluation of many resources, evaluation of portfolios on an hourly basis and consistency in modeling, including least cost long-term capacity expansion planning optimization, simulated dispatch of resources and probabilistic modeling); and
- A more robust risk analysis, which encompasses a broad consideration of risks and an exploration of resource performance over a wide range of potential futures.

Based on this planning process and detailed analysis, Vectren has selected a preferred portfolio plan that significantly yet prudently diversifies the resource mix for its generation portfolio with the addition of significant solar and wind energy resources, the retirement or exit of four coal units, and continued investment in energy efficiency. These resources are complemented with dispatchable resources including continued operation of Culley Unit 3 and the addition of two flexible natural gas Combustion Turbines (CTs). The gas units represent a much smaller portion of Vectren's generation portfolio as compared to the 2016 IRP preferred portfolio while still providing reliable capacity and energy. The highly dispatchable and fast-ramping gas units are an important match with the significant renewable investment, enabling Vectren to maintain constant electric supply during

potentially extended periods of low output from renewable energy sources. The units ramp quickly and provide load following capability, complimenting renewable energy production, which is expected to grow throughout the MISO footprint. Vectren's preferred portfolio reduces its cost of providing service to customers over the next 20 years by more than $320 million as compared to continuing with its existing generation fleet. Additionally, the preferred portfolio reduces carbon dioxide output by approximately 67% by 2025 and 75% by 2035 when compared to 2005 levels, which helps Vectren's parent company, CenterPoint Energy, achieve its commitments to environmental stewardship and sustainability, while meeting customer expectations for clean energy that is reliable and affordable.

Vectren's preferred resource plan reduces risk through diversification, reduces the cost to serve load over the next 20 years and provides the flexibility to continue to evaluate and respond to future needs through subsequent IRPs. The preferred portfolio has several advantages: including: 1) Energy supplied by this portfolio is generated primarily through a significant amount of near-term renewable solar and wind projects that take advantage of the Investment Tax Credit and the Production Tax Credit. This lowers portfolio costs and takes advantage of current tax-advantaged assets. 2) Two new, low-cost gas combustion turbines, continued use of Vectren's most efficient coal unit (Culley 3) and new battery storage resources, provide resilient, dispatchable power to Vectren's system that is complementary to significant investment in new intermittent renewable resources. This is very important, as coal plants, which have provided these attributes in the past, continue to retire in MISO Zone 6. 3) The portfolio provides flexibility to adapt to and perform well under a wide range of potential future legislative, regulatory, and market conditions. The preferred portfolio performed well under CO_2, methane constraints, and other related regulations such as a fracking ban. The cost position of this portfolio that is backed up by the two combustion turbine capacity resources does not change because the gas turbines predominantly run during peak load conditions. This provides a financial hedge against periodic instances of high market energy and capacity prices, 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 against purchases to remain poised to adapt to market shifts. 5) It includes new solar capacity when it is most economic to the portfolio. 6) Finally, it is timely. New combustion turbines can come online quickly to replace coal generation that retires by the end of 2023, minimizing in-service lag and reducing exposure to the market.

The resource options selected in this plan provide a bridge to the future. For example, CT's allow time for battery storage technology to continue to become more competitive in price and further develop longer duration storage capabilities. Further, should there be a need for new baseload generation in the future to accommodate a large load addition or to replace Warrick 4 and Culley 3, one or both CT's could be converted to a CCGT, a highly efficient gas energy resource. Even with the large commitment in the near term to renewable resources, additional renewable resources can be added over time.

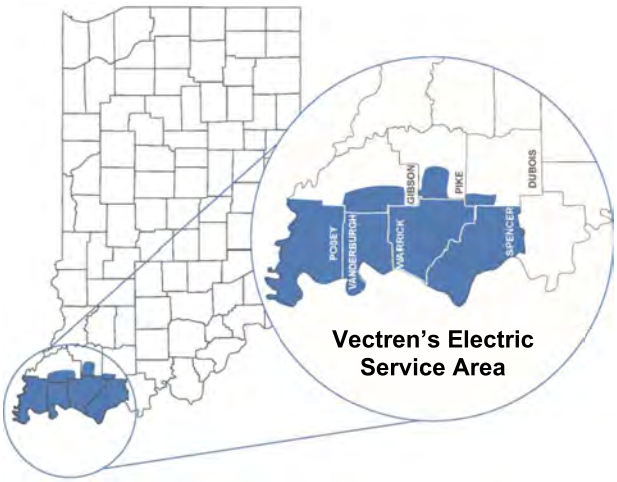
The preferred portfolio also provides several off-ramps (future transitional inflection points) should they be needed. 1) Vectren continues to speak with Alcoa about a possible extension of Warrick 4 (W4) joint operations through 2026. This option could provide additional time and shield Vectren customers from capacity purchases at a time where the market is expected to be tight, causing much higher projected prices than today. Additionally, time may be needed to allow Vectren to secure the level of renewable resources identified in the preferred portfolio and to allow for contingency for permitting and construction of new combustion turbines. 2) While Culley 3 is not scheduled to be retired within the timeframe of this analysis, including thermal dispatchable generation in this portfolio will allow Vectren flexibility to evaluate this option in future IRPs. 3) Vectren will work to secure attractive renewables projects from the recent All-Source RFP but will likely require a second RFP to fully secure 700-1,000 MWs of solar on multiple sites and 300 MWs of wind constructed over a span of several years. Issuing a second RFP provides two main benefits. It allows more local renewable options to select from, as some offered proposals are no longer available. Second, it provides additional time to better understand how MISO intends to move forward with market adjustments, such as

capacity accreditation and energy price formation. MISO's wholesale market is adapting to fleet transition that is moving toward intermittent renewable resources.

What follows is a summary of Vectren's process to identify this portfolio, focusing on Vectren's operations, an explanation of the planning process and a summary of the preferred portfolio.

II. Vectren Overview

Vectren provides energy delivery services to more than 146,000 electric customers located near Evansville in Southwestern Indiana. In 2018, approximately 44% of electric sales were made to large (primarily industrial) customers, 30% were made to residential customers and 26% were made to small commercial customers.



The table below shows Vectren generating units. Since the last IRP, Vectren has formally retired four, older small natural gas units[1] rather than investing significant capital dollars to ensure safety and reliability. Note that Vectren also offers customers energy efficiency programs to help lower customer energy usage and bills.

Unit	Installed Capacity ICAP (MW)	Primary Fuel	Year in Service	Unit Age	Coal Unit Environmental Controls[2]
A.B. Brown 1	245	Coal	1979	41	Yes
A.B. Brown 2	245	Coal	1986	34	Yes
F.B. Culley 2	90	Coal	1966	54	Yes
F.B. Culley 3	270	Coal	1973	47	Yes

[1] In 2018, Vectren retired BAGS 1 (50 MW). In 2019, Vectren retired Northeast 1&2 (20 MW) and BAGS2 (65 MW)

[2] All coal units are controlled for Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_X), Particulate Matter (dust), and Mercury. All coal units are controlled for Sulfur Trioxide (SO_3) and Sulfuric Acid ($H2S0_4$) except F.B. Culley 2.

Unit	Installed Capacity ICAP (MW)	Primary Fuel	Year in Service	Unit Age	Coal Unit Environmental Controls[2]
Warrick 4	150	Coal	1970	50	Yes
A.B. Brown 3	80	Gas	1991	29	
A.B. Brown 4	80	Gas	2002	18	
Blackfoot[3]	3	Landfill Gas	2009	11	
Fowler Ridge	50	Wind PPA	2010	10	
Benton County	30	Wind PPA	2007	13	
Oak Hill[4]	2	Solar	2018	<2	
Volkman Rd[5]	2	Solar	2018	<2	
Troy	50	Solar	2021		

III. Integrated Resource Plan

Every three years Vectren 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, low cost, 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.

Vectren utilized direct feedback on analysis methodology, analysis inputs, and evaluation criteria from stakeholders, including but not limited to Vectren residential, commercial and industrial customers, regulators, elected officials, customer advocacy groups and environmental advocacy groups. Vectren continues to place an emphasis on reliability, customer cost, risk, resource diversity, and sustainability. The IRP process has become increasingly complex in nature as renewable resources have become more cost competitive, battery energy storage has become more viable, and existing coal resources are dispatched less and less.

[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.

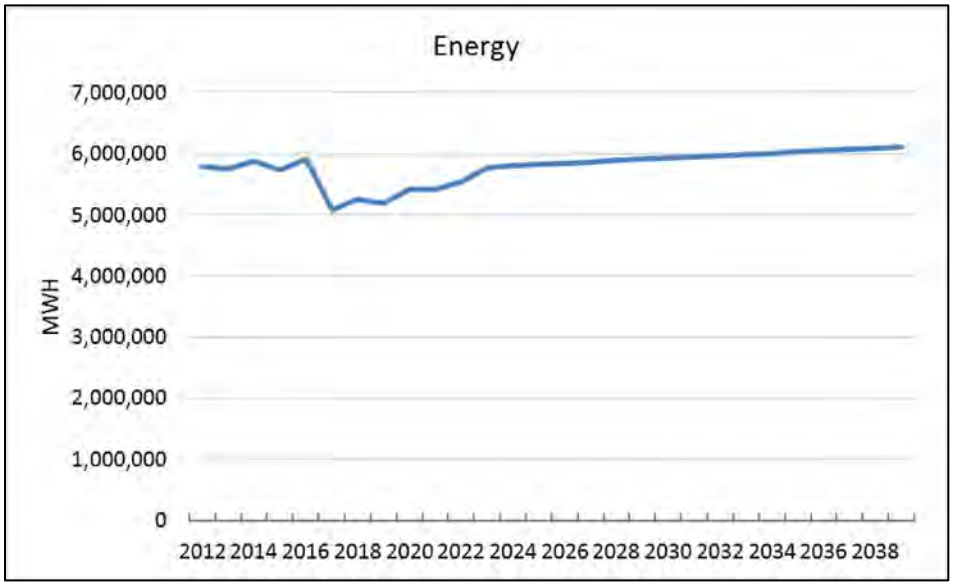
A. Customer Energy Needs

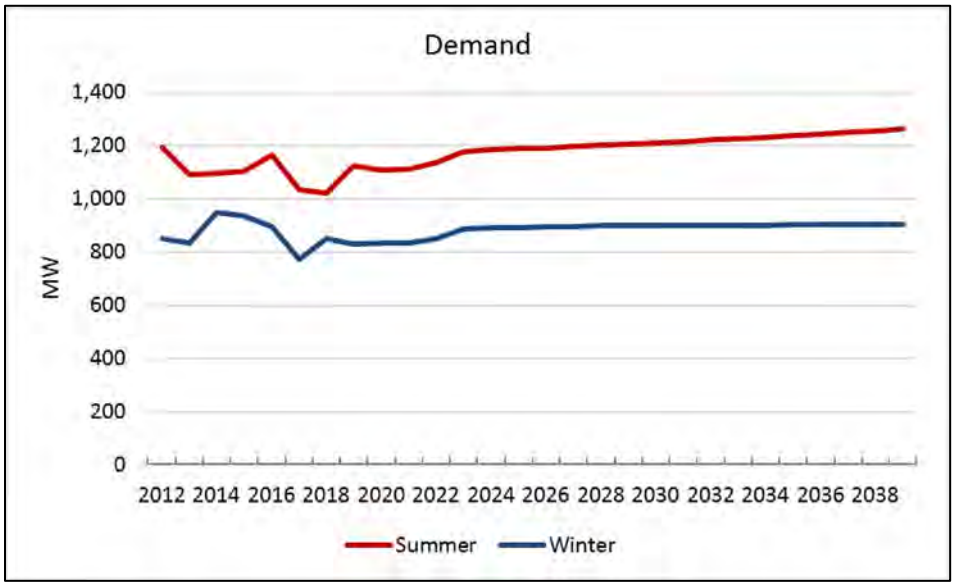
The IRP begins by evaluating customers' need for electricity over the 20-year planning horizon. Vectren worked with Itron, Inc., a leader in the energy forecasting industry, to develop a forecast of customer energy and demand requirements. Demand is the amount of power being consumed by customers at 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 Vectren purchases some power from the market, Vectren is required to have enough generation and energy efficiency resources available to meet expected customers' annual 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 (Midcontinent Independent System Operator) member, Vectren 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 that resources are available to meet this demand 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, Vectren ensured that its preferred portfolio would have adequate reserve margins for meeting both the winter and summer peak demand. Later in this document it is further explained how MISO is evaluating measures to help ensure year-round reliability.

Vectren 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

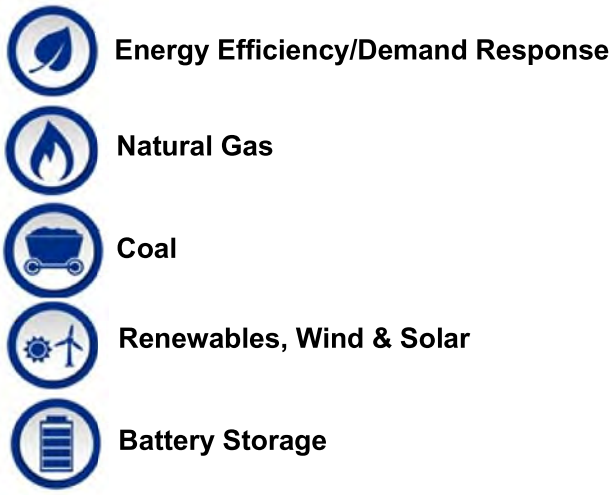
trends, population growth, price of electricity, weather, specific changes in existing large customer demand and customer adoption of solar and electric vehicles. Overall, customer energy and summer demand are expected to grow by 0.6% per year. Winter demand grows at a slightly slower pace of 0.5%.





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. Vectren considered both new and existing resource options. Burns and McDonnell, a well-respected engineering firm, conducted an All-Source RFP which generated 110 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 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, Vectren utilized other information sources for long term costs and operating characteristics for these resources and others over the entire 20-year period. Other options include continuation of existing coal units, conversion of coal units to natural gas, various natural gas resources, hydro, landfill gas, and long-duration batteries, as well as partnering with other load-serving entities. 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: projected low stable gas prices, low cost and projected high penetration of intermittent renewable resources, future of coal resources, new technology and projected changes in the MISO market to adapt and help ensure reliability.



i. Industry Transition

The cost of fuel used by generation facilities to produce electricity is also accounted for in evaluating the cost of various electric supply alternatives. Gas prices are near

record low levels and are projected to remain stable over the long term. Shale gas has revolutionized the industry, driving these low gas prices and has fueled a surge in low-cost gas generation around the country. Vectren's IRP reflects the benefit low gas prices provide to the market, as gas units are on the margin and typically set market prices for energy.

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 26% of total generation in 2018[6]. Meanwhile, the cost of renewable energy has declined dramatically over this time period due to improvements in technology and helped by government incentives in the forms of the Production Tax Credit for wind and the Investment Tax Credit (ITC) for solar, both of which are set to expire or ratchet down significantly over the next few years.

The move toward low cost 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 compete on price with low cost 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

MISO Energy Mix Transition (GWH) from 2005 to 2018 to 2030
(Based on Utility Announcements and State Integrated Resource Plans)*

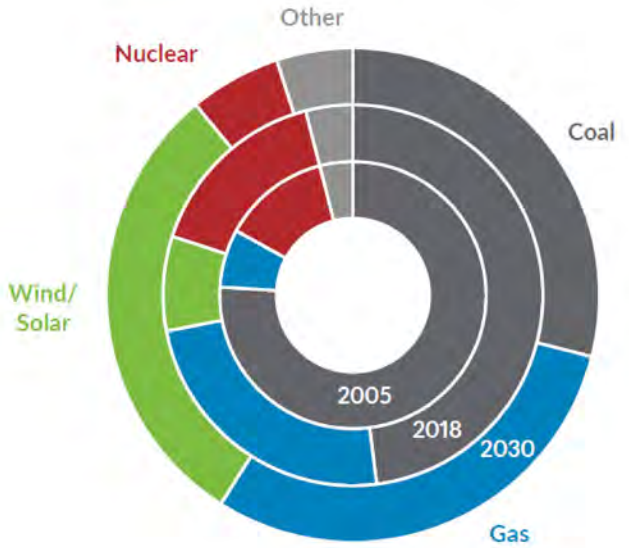


*Chart reflects ratios of generation.

[6] MISO Forward Report, March 2019, page 10. https://cdn.misoenergy.org/MISO%20FORWARD324749.pdf

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. 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, MISO expects the generation mix in 2030 to be much more balanced than in the past with roughly one third renewables, one third gas and one third coal. Some large nuclear plants remain but have also found it challenging to compete on cost.

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, 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 is in the process of studying 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.

To deal with these challenges, MISO has been working through a series of studies and has put forth guidance for how they intend to evaluate resources moving forward. One significant development is the recognition that all hours matter. In the past, MISO

resource adequacy requirements focused on only the peak hour each year. Recent MISO emergencies in all seasons have demonstrated that the system can experience potential energy shortfalls in any hour due to changing resource conditions. As such, MISO is planning for new requirements to ensure resources are available for reliability in each of the 8,760 hours of the year. Each resource has different operating characteristics and different output levels, depending on the season. Vectren has accounted for these changes by validating that portfolios in this analysis provide sufficient resources to meets its MISO obligations[7] in the two heaviest demand periods (summer/winter). MISO has initiatives underway that include new testing requirements to ensure that Demand Response (DR) resources are available when needed. MISO's annual Market Road Map process has prioritized the development of mechanisms to more accurately account for resource availability. This includes an evaluation of how to best incent resources with the right kinds of critical attributes needed to keep the system operating reliably. Incentives are contemplated for resources that are available (dispatchable), flexible (ability to start quickly and meet changing load conditions when needed) and visible (have a better understanding of customer owned generation in addition to larger utility assets). MISO expects that traditional dispatchable coal and gas resources will continue to provide resilience to the grid.

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 needed to move to more reliance on intermittent renewable resources. Lithium-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. Large scale batteries for utility applications have begun to emerge around the country, particularly where incentives

[7] Some portfolios have a heavy reliance on the market for both energy and capacity.

are available to lower the cost of this emerging technology or for special applications that improve the economics.

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 the reliability of the transmission system. Vectren has installed a 1 MW battery designed to capture energy from an adjacent solar project. This test project is providing 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. Currently, commercially feasible batteries are short duration, typically four hours. There are some commercially available longer-duration batteries that show promise, but these are still very expensive. 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. They can produce about 90-95 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 energy infrastructure, but they do not yet replace the need for other forms of dispatchable generation during extended periods without sun and wind. Vectren's All-Source RFP included bids for stand-alone batteries and batteries connected to solar resources.

C. Uncertainty/Risk

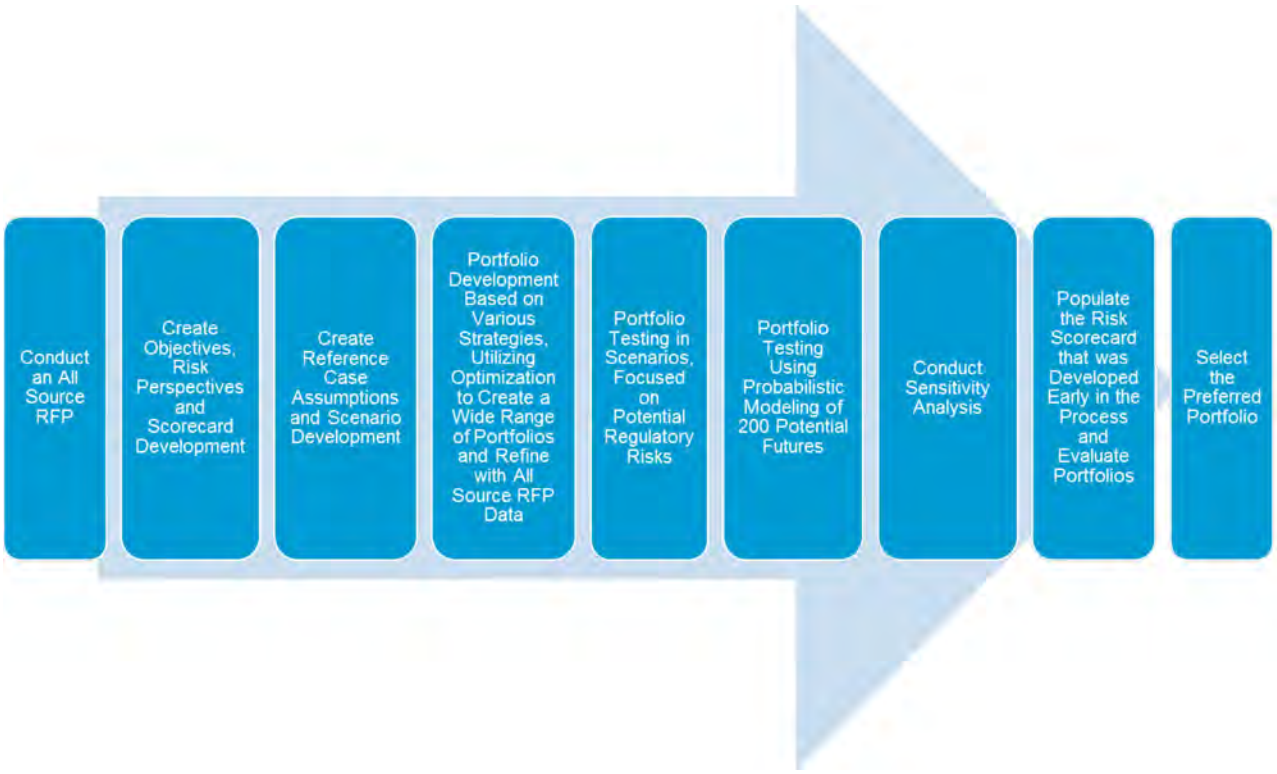
The future is far from certain. Uncertainty creates a risk that a generation portfolio that is reasonable under an anticipated future fails to perform as expected if the future turns out differently. Vectren's IRP analysis was developed to identify the best resource mix of generation and energy efficiency to serve customer energy needs over a wide range of possible future states. Vectren performed two sets of 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.

IV. Analysis

Vectren'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. Utilize the quantitative scorecard measures and judgement 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

Vectren reevaluated how to conduct the stakeholder process based on comments in the Director's report, stakeholder feedback and the Commission order in Cause number 45052. Careful consideration was taken to ensure that the time spent was mutually beneficial.

Each of the first three stakeholder meetings began with stakeholder feedback. Vectren would review requests since the last stakeholder meeting and provide feedback. Suggestions were taken and in instances where suggestions were not acted upon, Vectren made a point to further discuss and explain why not. Per stakeholder feedback, 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 phone calls/meetings in between each session per request.

Three of four public stakeholder meetings were held at Vectren in Evansville, IN. The final stakeholder meeting on June 15, 2020 was held via webinar due to the COVID-19 situation. Dates and topics covered are listed below:

August 15, 2019	October 10, 2019	December 13, 2019	June 15, 2020*
• 2019/2020 IRP Process • Objectives and Measures • All-Source RFP • Environmental Update • Draft Reference Case Market Inputs & Scenarios	• RFP Update • Draft Resource Costs • Sales and Demand Forecast • DSM MPS/ Modeling Inputs • Scenario Modeling Inputs • Portfolio Development	• Draft Portfolios • Draft Reference Case Modeling Results • All-Source RFP Results and Final Modeling Inputs • Scenario Testing and Probabilistic Modeling Approach and Assumptions	• Final Reference Case and Scenario Modeling Results • Probabilistic Modeling Results • Risk Analysis Results • Preview the Preferred Portfolio

- Moved final stakeholder meeting date per stakeholder request and the COVID-19 situation

Based on this stakeholder engagement, Vectren 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. Vectren utilized stakeholder information to create boundary conditions that were wide enough to produce plausible future conditions that would favor opposing resource portfolios (i.e. Indiana Coal Council (ICC) request to continue coal through 2029 or 2039 and environmental stakeholders' request to utilize all renewable resources by 2030). For example, the low regulatory future includes declining coal prices and higher gas prices, which was a request from the ICC. The High Regulatory scenario, which was heavily influenced by environmental stakeholders, is the other plausible future

bookend with a natural gas fracking ban (sustained high price), a social cost of carbon fee starting at $50 per ton in 2022 and lower renewables cost trajectory than what is expected. Additionally, an evaluation measure was adjusted based on direct stakeholder input. Vectren included the life cycle of carbon emissions for all resources in response to the ICC and environmental stakeholders. The table below shows key stakeholder requests made during the process and Vectren's response.

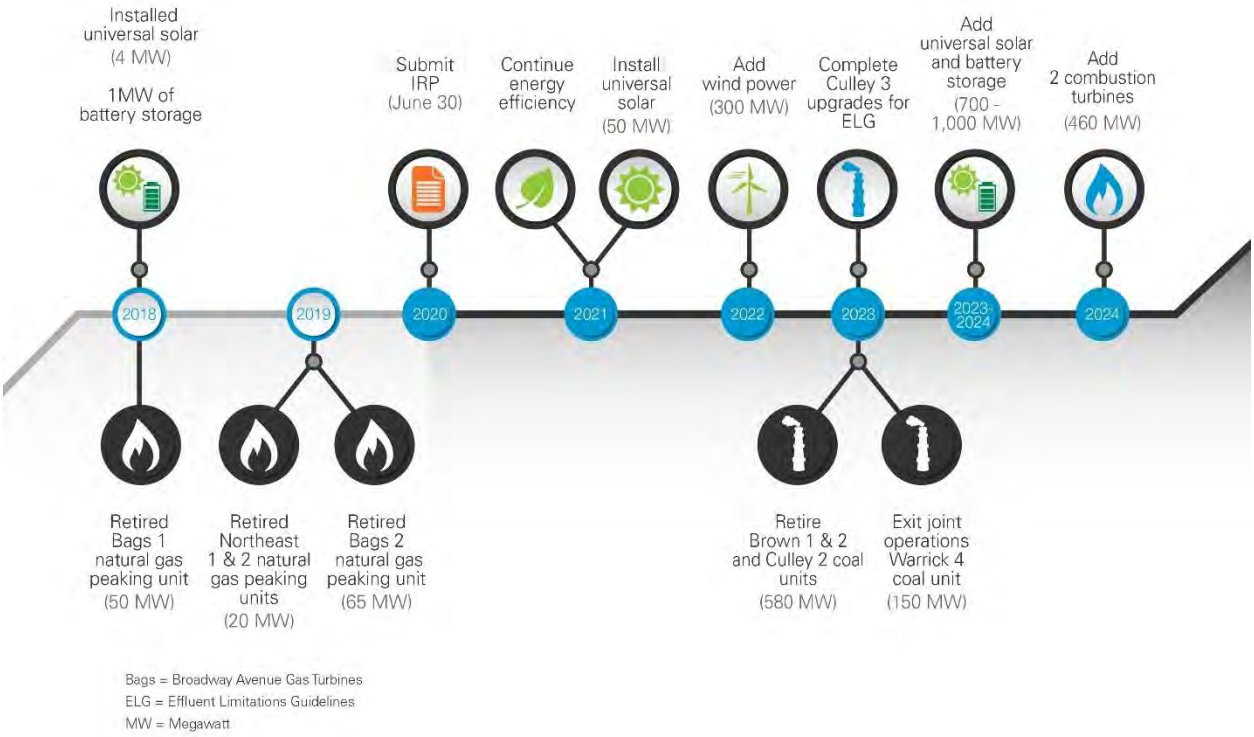
Request	Response
Update the High Regulatory scenario to include a carbon fee and dividend	Included a fee and dividend construct which assumed a balanced impact on the load (the economic drag from a carbon fee is neutralized by the economic stimulus of a dividend)
Lower renewables costs in the High Regulatory and 80% CO_2 Reduction scenarios	Updated scenario to include lower costs for renewables and storage than the Reference scenario
Consider life cycle emissions using CO_2 equivalent	Included a quantitative measure on the risk scorecard based on National Renewable Energy Lab (NREL) Life Cycle Greenhouse Gas Emissions (CO_2e) from Electricity Generation by Resource
Include a measure within the risk score card that considers the risk that assets become uneconomic	Included an uneconomic asset risk as a consideration in the overall evaluation. Not included in the scorecard.
Include a scenario with a carbon dividend modeled after HB 763 with a CO_2 price that was approximately $200 by the end of the forecast	Utilized a scenario with these prices to create an additional portfolio. Ultimately, this portfolio was not selected for the risk analysis, as the amount of generation built

Request	Response
	within modeling vastly exceeded Vectren's need and resulted in large energy sales
Reconsider the use of a seasonal construct for MISO resource accreditation	Reviewed calculation for solar accreditation in winter and utilized an alternate methodology, increasing accreditation in the winter
Include a CO_2 price in the reference case	Included mid-range CO_2 prices 8 years into the forecast. The Low Regulatory scenario did not include a CO_2 price, thus becoming a boundary condition

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

VI. The Preferred Portfolio

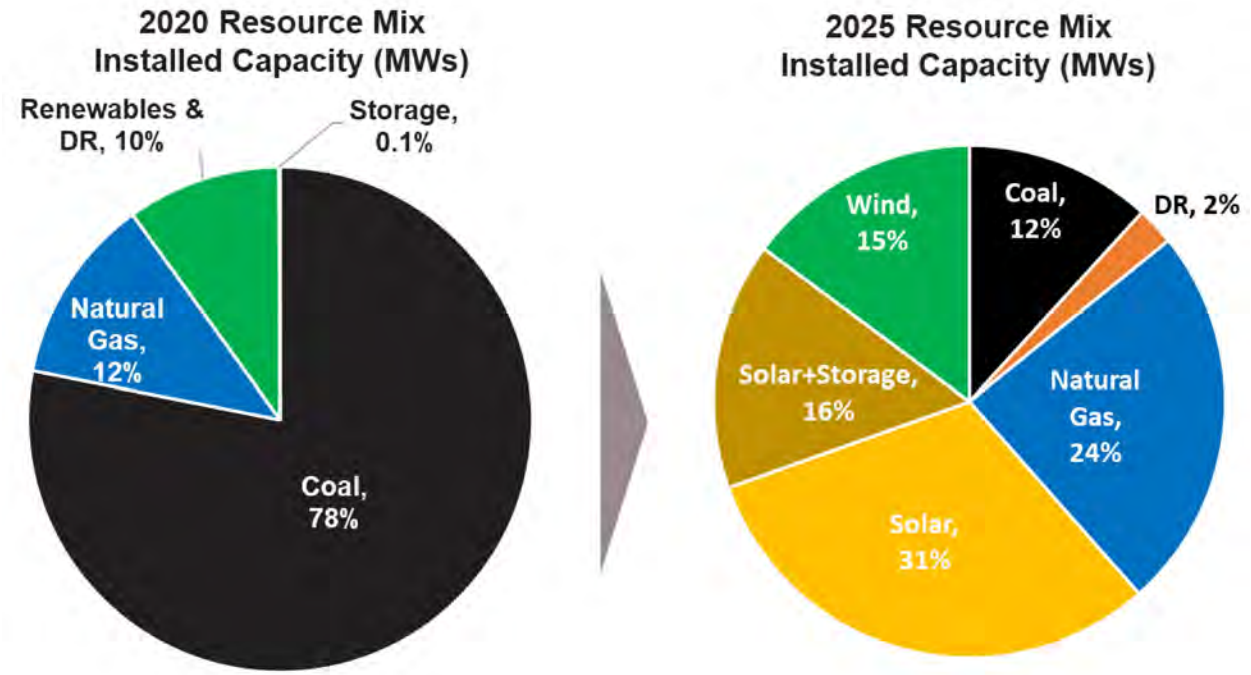
The Preferred Portfolio recommendation is to retire or exit 730 MWs of coal generation and replace with 700-1,000 MWs of solar generation (some connected to battery storage), add 300 MWs of wind backed by dispatchable generation that consists of 2 new Combustion Turbine (CT) gas units and maintaining Culley 3 (coal unit).



This preferred portfolio:

- Allows customers to enjoy the benefits of low-cost renewable energy, while ensuring continued reliable service as Vectren moves toward higher levels of intermittent renewable energy in the future.
- Saves customers over $320 million over the next 20 years when compared to continued operation of Vectren's coal fleet. The preferred portfolio is a low-cost portfolio in the near, mid and long term.
- Reduces lifecycle greenhouse gas emissions, which includes methane, by nearly 60% over the next 20 years. Direct carbon emissions are reduced 75% from 2005 levels by 2035.

- Includes a diverse mix of resources (renewables, gas and coal), 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 extend the contract with Alcoa for Warrick 4 for a few years and maintains the option to consider the replacement of Culley 3 in the future when appropriate based on continual evaluation of changing conditions. These options will be revaluated in future IRPs.
- 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.
- Adds some battery energy storage in the near term, paired with solar resources to provide clean renewable energy when solar is not available. Provides time for technological advances that will allow for high penetration of renewables across the system, further cost declines and further Vectren operational experience to meet Vectren's customers' energy needs.
- Continues Vectren's energy efficiency programs with near term energy savings of 1.25% of eligible sales and further long-term energy savings opportunities identified over the next 20 years. Vectren is committed to Energy Efficiency to help customers save money on their energy bills and will continue to evaluate this option in future IRPs.



VII. Next Steps

The preferred portfolio calls for Vectren to make changes to its generation fleet. Some of these changes require action in the near term. First, Vectren will finalize the selection process to secure renewable projects from the All-Source RFP and seek approval from the IURC for attractive projects. Second, the IRP calls for continuation of energy efficiency. Vectren filed a 2021-2023 plan with the IURC in June of 2020, consistent with the IRP. Third, Vectren intends to pursue two natural gas combustion turbines to provide dispatchable support to the large renewables based preferred portfolio. 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.

Vectren'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. Without incremental investment, the plant does

not comply with the ELG and other water discharge control requirements. Vectren therefore continues to talk to Alcoa about its plans.

- The availability of attractive renewable projects is currently being evaluated. Negotiations for resources must take place to finalize availability and cost of projects. The Coronavirus has put pressure on supply chains and put in jeopardy the ability of full utilization of the Production Tax Credit and Investment Tax Credit for some projects. Competition for these projects is steep, with multiple, on-going RFP processes in the state of Indiana.
- Finally, MISO continues to evaluate the accreditation of resources. Vectren will continue to follow developments to determine the right amount of renewable resources to pursue in the near term.

SECTION 1
OVERVIEW

1.1 COMPANY BACKGROUND

Vectren is a wholly owned subsidiary of CenterPoint Energy, Inc. On February 1, 2019, CenterPoint Energy, Inc. (NYSE: CNP) and Vectren Corporation (NYSE: VVC) completed a merger. The combined company, which is named CenterPoint Energy and headquartered in Houston, has regulated electric and natural gas utility businesses in eight states that serve more than 7 million metered customers.

Operation of Vectren's electric transmission and distribution services, including its power generation and wholesale power operations now fall into CenterPoint's Indiana Electric business. Vectren serves approximately 146,000 customers in Southern Indiana.

1.2 INTEGRATED RESOURCE PLANNING

Vectren takes integrated resource planning very seriously. The IRP is used as a guide for how Vectren 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.

Vectren is required to submit its Integrated Resource Plan (IRP) to the Indiana Utility Regulatory Commission (IURC) every three years and last submitted it in 2016 with a plan to transition its generation fleet away from a majority reliance on coal. Vectren began this IRP process by gathering feedback from stakeholders on the last IRP, the Final Director's Report for 2016 Integrated Resource Plans and the Indiana Utility Regulatory Commission's Order in 45052 (Vectren's 2018 generation transition filing). Additionally, Vectren worked more closely with IRP stakeholders than ever before to listen, inform and consider updates to the process, as discussed in Chapter 3 Public Participation Process.

The future is uncertain; several factors have helped to set the stage for this analysis. Gas prices remain historically low and are projected to be stable over the long term. Shale gas

has revolutionized the industry, driving these low gas prices. This has fueled a surge in gas generation investment, due to its low-cost energy and capacity value that it brings to the grid.

Renewable costs continue to decline and are producing competitively priced energy in the Midwest region, but still require backup for times when the wind is not blowing and the sun is not shining (on a daily and seasonal basis). Based on expectations of increasing penetration of renewables, particularly solar, MISO (Midcontinent Independent System Operator), Vectren's regional transmission operator, continues to evaluate rules and mechanisms that are needed now and in the future to maintain reliability. Vectren continues to monitor developments within MISO; the outcomes of two major studies are important for resource planning. 1) MISO is conducting a Renewable Integration Impact Assessment (RIIA) related to impacts of renewable energy growth in MISO over the long term. This study will assess implications to MISO's transmission needs and ability to effectively dispatch its members' generation fleet. 2) MISO is simultaneously conducting the Resource Availability and Need (RAN) initiative, which looks at more granular planning and accreditation of generation resources to account for a changing generation mix and resulting attributes, both of which are discussed in detail below.

In order to better evaluate renewable, energy storage and energy efficiency resources within the IRP analysis, Vectren chose to move to a more sophisticated IRP modeling tool than was used in the 2016 IRP, the Aurora modeling platform. It provided several benefits: 1) simultaneous evaluation of many resources, 2) evaluation of portfolios on an hourly basis and 3) consistency in modeling, including optimization, simulated dispatch of resources and probabilistic modeling. 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.

1.2.1 IRP Objectives

Vectren'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[8] of supply and demand resources to best meet customers' needs for reliable, reasonably priced, environmentally acceptable power over a wide range of future market and regulatory conditions, taking into account risk and uncertainty. Specifically, Vectren'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 back up renewable resources)

1.2.2 IRP Development

As mentioned above, Vectren incorporated feedback from IRP stakeholders, IURC staff and the Commission in developing the 2019/2020 IRP. Detailed feedback was provided to IRP stakeholders on August 15, 2019, in Vectren's first of four public stakeholder meetings in a presentation titled "2019/2020 IRP Process." This presentation provided the backdrop for several Vectren commitments to improve and strengthen the analysis, most notably with the addition of an All-Source RFP, but also other improvements, including but not limited to the following:

- Additional stakeholder input,
- More consistency in modeling,
- More comprehensive analysis and

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

- The evaluation of a wider mix of resources, including an exhaustive evaluation of existing resources.

Vectren worked closely with industry experts to develop a comprehensive analysis. Burns and McDonnell, now known as 1828 and Company, managed all aspects of the All-Source RFP. This analysis was utilized to provide current market pricing for resources and an opportunity for Vectren to pursue individual projects to help serve Vectren customers following the conclusion of the IRP. Pace Global, now known as Siemens Energy Business Advisory, worked with Vectren to conduct scenario development, modeling and a comprehensive risk analysis, which included both scenario based and probabilistic modeling.

1.3 CHANGES SINCE THE 2016 IRP

Several developments have occurred since the last IRP was submitted in 2016, which helps 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. Vectren realizes that conditions will change, and tis analysis was designed to test portfolios under a wide range of plausible futures.

1.3.1 Generation and Storage Filings

1.3.1.1 Generation Transition Plan

Following the conclusion of the 2016 IRP, Vectren began a generation transition plan to replace the majority of its coal fleet with a highly efficient, large, natural gas plant and a 50 MW universal solar plant. Vectren also proposed to continue operation of its most efficient coal unit by installing certain environmental compliance equipment. This was done through two separate filings in Cause numbers 45052 and 45086.

In April 2019, the IURC granted partial approval of Vectren's Smart Energy Future electric generation transition plan which included approval to retrofit F.B. Culley 3, Vectren's largest, most-efficient 270 MW coal-fired unit and to proceed with construction of a 50 MW universal solar array. The request to construct a 700-850 MW combined cycle natural gas power plant was not approved. The following concerns were raised in opposition to the proposal:

- Vectren selected a Combined Cycle Gas Turbine (CCGT) that was too large for a small utility
    - Did not adequately consider flexibility to change paths, adding stranded asset risks
    - Did not consider fuel or geographic diversity
- Risk analysis did not consider the full range of portfolios
    - Did not fully explore options at the Brown plant (conversion or scrubber alternatives)
    - Need to more fully consider customer-generator opportunities
    - Did not fully consider energy and capacity purchases
    - Did not consider smaller gas plant options in the risk analysis
- Vectren's analysis disadvantaged renewable resources
    - Vectren did not make a serious effort to determine the price and availability of renewables
    - The RFP was too restrictive
- Vectren did not fully respond to the Director's report critiques in updated CPCN analysis
    - Did not update the risk modeling
    - Did not consider the full range of gas prices (including methane regulation)

Each of these concerns is addressed in detail within this IRP analysis and selection of the preferred portfolio. All will be addressed in detail within this report.

1.3.1.2 Urban Living Research Center (ULRC)

Vectren has partnered with Scannell to develop the Urban Living Research Center (ULRC), a living laboratory facility which will serve as a leading-edge research vehicle for Vectren to better understand and partner with customers. The ULRC is part of a larger, mixed-use, multifamily development called the "Post House" which opened on June 1, 2020. The Post House/ ULRC originated as a partnership in response to the Regional Cities Initiative, which aims to retain and attract talent by enhancing the quality of Indiana communities. The ULRC will include a mix of natural gas and electric, efficient and smart energy-using devices, such as lighting, HVAC, water heating and instrumentation, that will help the Company research new products and services to help customers manage their energy use. The Company was awarded funding from the Department of Energy's Building Technologies Office to utilize toward the ULRC to advance research in grid-interactive buildings in partnership with Oak Ridge National Laboratory. Based on actual construction of the facility and the available rooftop space, Vectren plans to install rooftop solar. Lithium-ion battery storage in both front- and behind-the-meter configurations was also planned for the facility but was removed from the project due to concerns related to the placement of Lithium-ion batteries indoors in light of evolving safety standards and best practices. Lessons learned and data from this project could help future integrated resource planning efforts.

1.3.1.3 Volkman and Oak Hill Universal Solar and Battery Projects

In 2017, Vectren filed for and received approval to construct two 2-MW universal solar projects that are currently in operation; one near North High School in northern Vanderburgh County and the second near Oak Hill Cemetery near Morgan Ave., which is through a partnership with the City of Evansville. Both sites have been constructed and have been generating power since December 2018. The Volkman Road project also includes battery storage with the ability to discharge one megawatt of power per hour over a four-hour period.

1.3.2 Environmental Rules

1.3.2.1 Rules Update

1.3.2.1.1 Air

In March 2015, USEPA entered into a consent decree to resolve litigation concerning deadlines for completing 1-hour sulfur dioxide (SO2) National Ambient Air Quality Standard (NAAQS) designations. The agreement required USEPA to designate as nonattainment, attainment or unclassifiable, certain areas that included sources that emitted more than 16,000 tons of SO2 in 2012 or emitted more than 2,600 tons of SO2 with an average emission rate greater than 0.45 lbs./MMBtu. USEPA identified five sources in Indiana that exceeded this threshold, including the A. B. Brown plant. In order for Posey County to meet the attainment designation, Vectren had to agree to a lower SO2 emission rate for the A.B. Brown plant. Vectren worked with IDEM and accepted a Commissioner's Order to voluntarily lower the plant's SO2 emission limit, which went into effect April 19, 2016.

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 electric generating units (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 Electric Generating Units (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 July 2022 with compliance planned to begin within 24 months of submission.

In December 2015, Vectren agreed to a modified Consent Decree to resolve alleged air violations at the F. B. Culley and A. B. Brown plants. The negotiated settlement required Vectren to eliminate the scrubber bypass stack for F. B. Culley Unit 2 and install equipment to mitigate SO3 emissions from A. B. Brown Units 1 and 2 and F. B Culley Unit 3. Each unit is required to maintain a H2SO4 emission limit to demonstrate compliance.

The state of Indiana has developed a state implementation plan (SIP) to administer the three trading programs under the Cross-State Air Pollution Rule (CSAPR) and allocate allowances for affected electric generating unit starting in 2021. The SIP was published in the Federal Register on December 17, 2018. The intent of CSAPR is to address power plant emissions that cross state lines and contribute to ozone and fine particle pollution in other states.

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 waste waters 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 FGD waste waters.

While the 2015 final rule includes reference to multiple waste waters, the key elements applicable to Vectren are FGD waste waters and ash transport waters. Specifically, FGD waste waters 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 from November 1, 2018 to November 1, 2020, but the no later than December 31, 2023 date for completion remained in place.

The A.B. Brown and F.B. Culley NPDES permits were renewed in 2017 and have since been modified as appropriate to allow for the BATW date extension allowed by the ELG Postponement Rule. As required by the ELG Rule and consequently the NPDES permits, FBC has ceased the discharge of FATW and will complete the conversion of bottom ash to a dry system in fall 2020. For FGD waste waters at F.B. Culley, alternate, but more restrictive limits can be voluntarily agreed to which would automatically extend the applicability date to December 31, 2023. Technology to meet the more restrictive limits could include the installation of zero liquid discharge equipment that would eliminate all discharge of FGD wastewater. The A.B. Brown permit was modified following publication of the ELG Postponement Rule. Currently, A.B. Brown is required to stop discharging both Fly Ash Transport Water and Bottom Ash Transport Water by November 2021. An additional ELG reconsideration rule, proposed in 2019, maintained the prohibition on the discharge of fly ash transport water and prohibits the discharge of bottom ash transport water, except in limited, specific circumstances, such as significant storm events.

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 Vectren 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" proposed rule provides an option for utilities to submit a demonstration (application) for surface impoundments to remain active beyond the current rule closure dates, however no longer than October 15, 2023.

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 is scheduled to be converted to a dry system in the Fall of 2020. Work is also taking place to convert the FGD system to zero liquid discharge technology. These two technologies will 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 is currently undergoing closure, with those activities scheduled to be completed by December 2020. The closure design includes the construction of a lined contact storm water pond, which will receive 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 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 soon. Plans are currently underway to prepare for the excavation of all material from the A.B. Brown ash pond, with a majority of the ash being sent for beneficial reuse.

1.3.3 Electric TDSIC

The IURC approved Vectren's seven-year infrastructure improvement plan for the period of 2018-2024 (Cause No. 44910). This plan helps to build/rebuild high–voltage transmission lines, replaces substation transformers, rebuilds electric circuits and includes distribution automation. These improvements will help Vectren to continue to reliably deliver power to its customers now and in the future. Additionally, these improvements, will allow more flexibility in resource planning by improving power flows across Vectren's system, particularly the addition of the East-West transmission line that will connect the F.B. Culley Plant site on the east side of the system with the A.B. Brown plant site on the west side.

1.3.3.1 Advanced Metering Infrastructure (AMI)

In 2017, Vectren began installation of AMI smart meters as a key part of Vectren's grid modernization plan. Vectren has since successfully installed meters across its territory. AMI provides access to much more granular customer load data and will help Vectren 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. Vectren customers have already received many benefits in the near term for billing, quicker service response time and quicker responses to power outages; however, the long-term benefits will take time and have not been fully realized by the compilation of this IRP.

1.3.4 IRP Rule Making Process

Revisions to Integrated Resource Planning were made via RM# 11-07, which began in 2010. Vectren voluntarily followed the draft rule in 2014 and 2016 IRPs, which included a public stakeholder process. In 2019 the rule was finalized and can be found in the IRP Rule Requirements Cross reference table of this document. Major updates to the rule included moving from a two year to three-year cycle and several updates to the stakeholder process, including the number of required stakeholder meetings, which is now three.

1.3.5 DSM Filing

On April 10, 2017, Vectren filed with the Indiana Utility Regulatory Commission (IURC) a Petition seeking approval of Vectren's 2018-2020 Energy Efficiency Plan (2018-2020 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 $28.6 million, with $9.5 million in 2018, $9.6 million in 2019 and $9.5 million in 2020. The Plan includes a portfolio of programs designed to achieve 111 million kWh in energy savings and 26,000 KW in demand reduction during the three-year period.

On December 28, 2017, the IURC issued an Order approving Vectren's 2018-2020 Energy Efficiency Plan (2018-2020 EE Plan) pursuant to Section 10. Vectren 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 1.1 – 2018-2020 Portfolio Summary of Participation, Impacts, & Budget

Portfolio Participation, Impacts & Budget								
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	First Year Cost/kWh *
2018	334,626	36,656,341	7,430	$ 8,050,391	$ 937,436	$ 500,000	$ 9,487,827	$ 0.23
2019	354,120	38,069,188	7,607	$ 8,433,276	$ 960,110	$ 200,000	$ 9,593,386	$ 0.23
2020	225,065	36,347,642	7,750	$ 8,370,366	$ 960,225	$ 200,000	$ 9,530,591	$ 0.24

* Cost per kWh includes program and indirect costs for budget. First year costs are calculated by dividing total cost by total savings and do not include carryforward costs related to smart thermostats, BYOT and CVR program.

1.3.6 Alcoa Contract

Alcoa and Vectren have jointly owned and operated the 300 MW Warrick 4 unit since 1970. In 2016, Alcoa split into two separate public companies and Alcoa Inc., as owner of the Warrick site, closed the aluminum smelter and greatly reduced load at the Warrick site. Alcoa also issued notice to Vectren that it would terminate and exit the joint operations of Warrick 4. However, Alcoa later reopened the smelter. After filing the 2016 IRP, Vectren worked with Alcoa to extend joint operations of Warrick unit 4 until December 31, 2023. The Warrick power plant consists of four generating units: three 150 Megawatt (MW) industrial units wholly owned by Alcoa and one 300 MW electric generating unit (Warrick 4) that is jointly owned by 50% Alcoa and 50% Vectren. Alcoa's power plant provides most of its 600 MW electric generation, if not all, to meet the electric demand of the Warrick Operations facility with the smelter being most of that demand. Alcoa's interest in continuing to operate the jointly owned Warrick 4 is unclear. As Vectren sought to maintain flexibility in this IRP, the company approached Alcoa to see if there was any potential to continue jointly operating Warrick 4 beyond 2023. Alcoa commented that it would possibly consider jointly operating the unit for an additional three years. While there is no commitment to run past 2023, Vectren included a three-year Warrick 4 extension possibility within the IRP modeling analysis as an option to maintain flexibility. Part of Alcoa's evaluation of the future of Warrick 4 is the potential need to invest in environmental control upgrades to continue operating the unit beyond 2023.

1.3.7 Merger with CenterPoint Energy

On February 1, 2019, CenterPoint announced the successful completion of the merger between Vectren and CenterPoint. The combined company, which is named CenterPoint Energy and headquartered in Houston, has regulated electric and natural gas utility businesses in eight states that serve more than 7 million metered customers. These utilities consist of the following:

- Electric utility business – CenterPoint Energy maintains wires, poles and electric infrastructure serving 2.4 million metered customers in the greater Houston area and 146,000 customers in Indiana. The company also owns and operates approximately 1,200 megawatts of power generation capacity in Indiana. CenterPoint Energy's Texas electric utility business is headquartered in Houston and its Indiana electric utility business is headquartered in Evansville, Ind.
- Natural gas utility business – CenterPoint Energy sells and delivers natural gas to 4.5 million homes and businesses in eight states: Arkansas, Indiana, Louisiana, Minnesota, Mississippi, Ohio, Oklahoma and Texas, including the high-growth areas of Houston and Minneapolis. The company's natural gas utility business is headquartered in Evansville.

1.3.8 FERC Grid Resilience and MISO Initiatives

Grid resilience became a national topic of interest in 2017 when the Department of Energy issued a Notice of Proposed Rulemaking (NOPR) for the Federal Energy Regulatory Commission’s (FERC) consideration. The basis of the NOPR was that due to the large amounts of retiring dispatchable generation, namely nuclear and coal, the nation’s bulk electric system was susceptible to power interruptions during extreme events and that it would be ill-suited to recover from these events. In January of 2018, FERC terminated the NOPR and directed each regional transmission owner (RTO) to evaluate its own resiliency, defined as the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to and/or

rapidly recover from such an event. MISO, the RTO that Vectren is a member of, filed comments to FERC stating its grid is resilient due to its robust electric and gas transmission infrastructure and its diverse generator makeup that spans a region from Ontario to the Gulf Coast. Furthermore, MISO stated footprint diversity is a staple of MISO's annual Value Proposition and is the cornerstone that MISO points to that ensures resiliency. MISO also noted several areas in which it would focus efforts to ensure continued resilience, namely through transmission planning, best in class technological tools and engagement with state and local regulators to assist in measurement and planning for local systems that may be vulnerable to high-impact events.

MISO's Resource Availability and Need (RAN) Initiative and its Renewable Integration Impact Assessment (RIIA) are the two current methods in which it is dealing with its evolving grid to help keep the system resilient and reliable. 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.

1.3.8.1 MISO Resource Availability and Need (RAN)

As a reaction to the increasing frequency, duration and ability for Max-Gen Events to occur within all periods of the year, in 2018 MISO implemented its Resource Availability and Need (RAN) initiative. The goal of this initiative is "ensure the processes in use appropriately assure the conversion of committed capacity resources into sufficient energy every hour of the Planning Year. A dramatically changing landscape has made this conversion process increasingly more uncertain. Therefore, an issue and solution development effort will help MISO and its stakeholders identify and meet the challenges posed by current and future portfolio and technology changes facing the region[9]."

[9] MISO Resource Availability and Need Issue Summary: page 1, January 12, 2018 https://www.misoenergy.org/api/documents/getbymediaId/96780

The RAN initiative has led to market mechanism reform that is currently underway. Such reform has included changes to the ability to interrupt customers enrolled as Load Modifying Resources/Interruptible Load. MISO currently has reform initiatives[10] that are high priority, including:

- Emergency Energy Pricing, which would allow higher cost energy resources to set pricing, thereby increasing energy pricing during emergency events,
- Increasing the Energy Offer Cap from $1,000/MWh to $2,000/MWh, thereby allowing generation to double its maximum offer price and allow prices to reach a higher threshold and
- a Seasonal Planning Resource Auction construct, which could break up the current annual capacity auction into seasons (winter and summer auctions) that would adjust the PRMR and capacity accreditation for resources during these periods. This initiative is in the primary phase of stakeholder vetting, with a possibility of tariff revisions submitted next year and could be in effect as early as the 2022-23 Planning Year.

1.3.8.2 MISO Renewable Integration Impact Assessment (RIIA)

With increased levels of intermittent renewable generation, operating the grid becomes increasingly more complex. To help understand what is needed in the long term to deal with this complexity, in 2017 MISO launched its Renewable Integration Impact Assessment (RIIA) study to find system integration inflection points. In other words, to find out where there may be potential issues as renewable penetration increases from 10%, 20%, 30% or beyond. MISO is focusing on a few key areas: Resource Adequacy, Energy Adequacy and Operating Reliability. As discussed further in this document, the resource adequacy portion of the analysis has already yielded actionable insights into integrated resource planning, which have been incorporated into Vectren's 2019/2020 analysis, particularly the amount of capacity that will likely be accredited to wind and solar resources over time based on penetration rate and expected output under peak

[10] MISO Market Roadmap, February 2019: https://cdn.misoenergy.org/MISO%20Market%20Roadmap194258.pdf

conditions. MISO calls this Effective Load Carrying Capability (ELCC). This study illustrates the need for dispatchable resources that support high renewable penetrations as the peak load, net of renewable generation, pushes farther into the evening after the sun goes down. Flexible, dispatchable resources are needed to meet this need quickly.

1.3.9 2016 IRP Director's Report

Each year, the Director to the IURC electric division issues a critique of IRPs. The 2016 IRP Director's report listed a balance of positive comments, coupled with improvement opportunities for Vectren. The table below shows the improvement opportunities with a brief description of how the comment was addressed within the 2019/2020 IRP:

Figure 1.2 – IRP Improvements Based on 2016 IRP Director's Report

Improvement Opportunities	Addressed
Include lower and higher boundary scenarios to create a wider range of portfolios	A wider range of forecasts were considered for key inputs within scenario development
Model a wide range of portfolios	Vectren modeled 10 portfolios in the risk analysis, utilizing feedback from multiple stakeholders to ensure many potential paths were covered, from continue most coal to all renewables by 2030
Strategist model did not consider enough options simultaneously	Utilized Aurora, which did consider all resources simultaneously
Update risk analysis methodology to be less qualitative and more encompassing of known risks. Clearly define risk analysis methodology	Included known risks within scenario development and the risk analysis, including, but not limited to CO_2 cost, potential methane regulations, possible

Improvement Opportunities	Addressed
	shale gas ban, uneconomic asset risk, etc.
Explore other options for modeling EE cost options and make greater use of a Market Potential Study (MPS) and Clearly define Energy Efficiency Methodology	Worked closely with stakeholders throughout the development process to develop EE modeling inputs using the latest MPS
More consideration given to Warrick unit 4 in scenario development	Warrick unit 4 extension (3 year) was considered within scenario optimizations. Discussions with Alcoa continue

1.3.10 Statewide Energy Policy Analysis

In 2019 the General Assembly created a task force to develop energy policy recommendations, and at this time, that work is ongoing.

The 21st Energy Policy Development Task Force was created by HEA 1278 (2019) to develop recommendations for the General Assembly and the Governor on the following:

1. Outcomes that must be achieved in order to overcome any identified challenges concerning Indiana's electric generation portfolios, along with a timeline for achieving those outcomes.
2. Whether existing state policy and statutes enable state regulators to properly consider the statewide impact of changing electric generation portfolios and, if not, the best approaches to enable state regulators to consider those impacts.
3. How to maintain reliable, resilient and affordable electric service for all electric utility consumers, while encouraging the adoption and deployment of advanced energy technologies.

In order to arrive at its recommendations, the task force will examine existing policies and how shifts in generation portfolios may impact system reliability, grid resiliency and affordability of electric service. The task force will issue its recommendations by December 1, 2020. Any outcomes that require statutory changes will likely be proposed in the 2021 legislative session.

Additionally, HEA 1278 passed in 2019 and required the IURC to conduct a statewide analysis of impacts of transitions in fuel sources and other electric generation resources, as well as the impacts of new and emerging technologies on electric generation and distribution infrastructure, electric generation capacity, system reliability, system resilience and the cost of electric utility service for consumers. IURC staff is working with Laurence Berkeley National Lab, Indiana University and the State Utility Forecasting Group. Results will be available this summer to help inform the 21st Energy Policy Development Taskforce.

Vectren stands ready to act as a resource to members of the 21st Energy Policy Development Task Force as progress is monitored. To this point, task force meetings have served as information-gathering sessions on various topics related to electric generation and delivery. Following the conclusion of the task force's work, Vectren will work collaboratively with policymakers and all stakeholders to help ensure a bright energy future for the State of Indiana.

1.3.11 HB 1414

The Indiana General Assembly passed legislation pertaining to electric generation during the 2020 legislation session. HEA 1414 Electric Generation was signed into law by Governor Holcomb on March 21, 2020 and provides the following:

- A public utility that owns and operates a reliable capacity electric generation resource must operate and maintain the unit using good utility practices and in a manner reasonably intended to support the availability of the unit for dispatch

- The bill sets parameters around a public utility's decision to retire, sell or transfer a reliable capacity resource with a capacity of at least 80 megawatts before May 1, 2021:
    - The utility must first provide written notice of its intent to do so to the IURC
    - The IURC must conduct a public hearing to receive information and issue analysis and conclusions, after which the utility may proceed, if doing so aligns with the preferred portfolio in its most recent IRP
    - If the planned retirement, sale or transfer was not included in the most recent IRP, the utility may not proceed for at least six months from the date of the commission's receipt of the written notice
    - If the utility cites a federal mandate as the basis for the planned retirement, sale, or transfer of the reliable capacity resource, the IURC may consider the status of the mandate in its analysis and conclusions.

Passage of HEA 1414 did not impact the selection of the preferred portfolio. The timing of Vectren's IRP is such that no retirements of electric generating stations could take place before the May 1, 2021 date in the legislation.

1.3.12 COVID-19

COVID-19, the disease caused by the coronavirus, has led to unprecedented changes in the energy industry as it has affected every aspect of life. The energy industry has seen demand drop since March of 2020, on average 6-10%, while commodity prices have decreased at a steep rate. This recent pandemic is still underway as of the writing of this document and the effects and duration are still largely unknown. The scenarios in this IRP account for a range of outcomes and the Low Load scenario is illustrative of the effects from a wholesale market pricing perspective. The following sections are independent of COVID-19 as the studies were performed prior to its onset and constitute resource planning for a 20-year period. The preferred portfolio includes multiple off-ramps, which help mitigate the risk that demand does not grow to pre-Covid-19 levels.

1.3.13 Contemporary Issues

Vectren participates in the Commission's IRP Contemporary Issues Technical Conference held each year. In 2019, the Conference was held on April 15, 2019. The Conference also covered topics such as database management, integration of DERs, incorporation of load shapes into planning, the changing availability and flexibility requirements of MISO Resource Availability and Need (RAN) initiative, long-term utility planning assumptions and procurement decisions, preliminary lessons learned from NIPSCO's all-source RFP, risk analysis and life cycle analysis of greenhouse gas emissions.

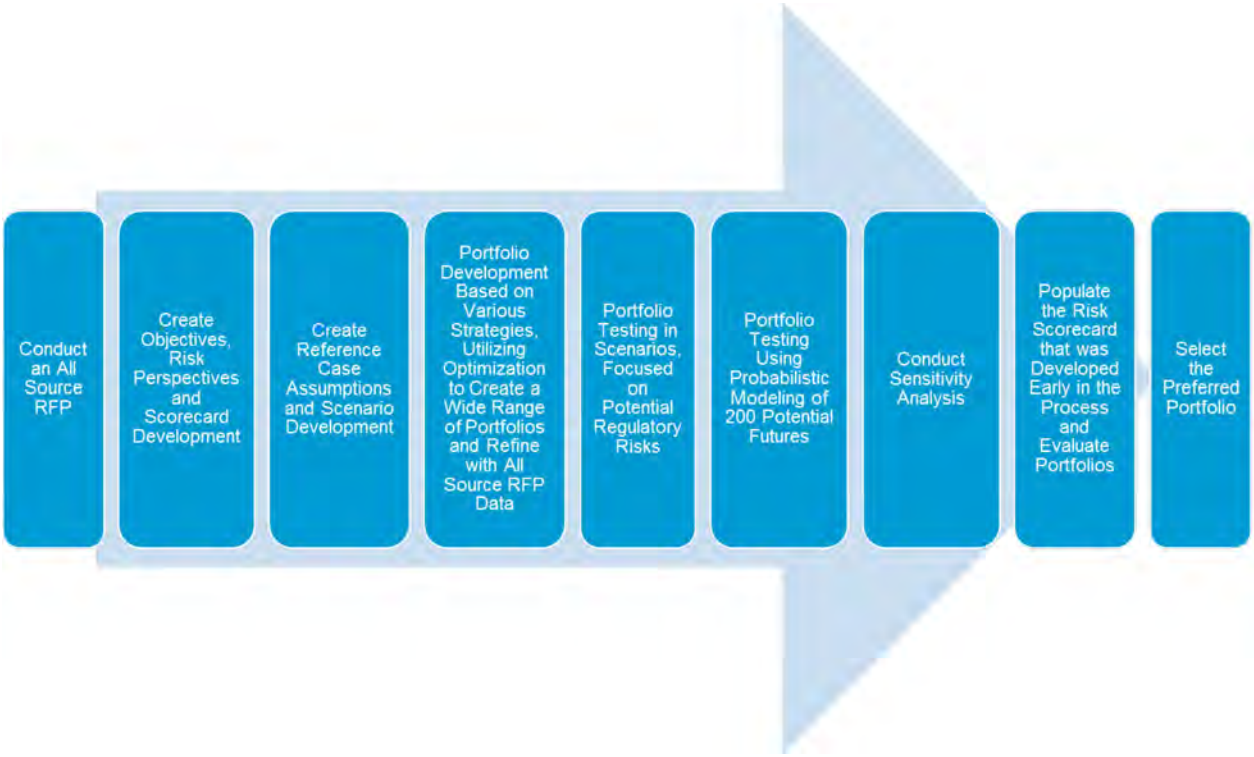
Several of these topics were timely and influential within Vectren's analysis. For example, the MISO RAN discussion, which included and expected focus on resource availability and flexibility to meet daily and variable energy needs, as well as a need for a holistic solution for seasonal resource adequacy. NIPSCO's discussion of All-Source RFP and lessons learned for the IRP was helpful as Vectren conducted its first All-Source RFP for this analysis. Finally, EVA's discussion on the need for Life Cycle Analysis (LCA) of carbon emissions analysis influenced Vectren's decision to include a life cycle greenhouse gas emissions variable within the risk scorecard.

SECTION 2
VECTREN'S IRP PROCESS

2.1 VECTREN'S IRP PROCESS

Vectren's 2019/2020 IRP followed a very structured, comprehensive process over a 14-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 that 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 – Vectren IRP Process



The following sections describe each step in the analysis.

2.2 Conduct an All-Source RFP

Vectren 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, Vectren 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, that will be discussed in further detail.

Within the context of the 2019/2020 IRP process, Vectren 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 Vectren in the marketplace to meet the needs of its customers. Dependent upon further evaluation of aging resources and prior to the 2019/2020 IRP, there was a potential capacity need of approximately 700 MW of accredited capacity beginning in the 2023/2024 planning year. Vectren sought flexibility when defining potential resource combinations and encouraged RFP respondents to offer available projects with less than, or more than, 700 MW. Vectren 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 beginning prior to or after the 2023/2024 planning year. Vectren 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, Vectren sought to satisfy the identified capacity need through either a single resource or multiple resources including dispatchable generation, load modifying resources (LMRs)/demand response (DRs), renewables, stand-alone and paired storage and contractual arrangements.

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

All Respondents were directed to interface with Burns & McDonnell 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 Burns & McDonnell. Respondents were contacted for additional data or clarifications by Burns & McDonnell via a designated Vectren RFP e-mail address, VectrenRFP@burnsmcd.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 Vectren customers with a safe, reliable and affordable power supply.

2.3 OBJECTIVES, RISK PERSPECTIVES and SCORECARD DEVELOPMENT

Vectren's IRP process is designed to assure 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 Vectren 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, Vectren also focused on increasing the diversification of its supply sources. As part of the IRP, Vectren 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 Vectren to identify the portfolio of supply-side and demand-side resources on a competitive economic basis.

The resulting least cost portfolios reflect a combination of market, regulatory or technology specified conditions and market input parameters (for example, identify the least cost portfolio consisting of all renewables by 2030 using reference case market forecasts). While cost is an important objective, it is by no means the only objective. Vectren has several important objectives, each of which needs to be considered when evaluating the best portfolio for its stakeholders over time. Moreover, Vectren 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.

Vectren's IRP strategy is designed to accommodate ongoing changes and uncertainties in the market. Vectren'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, Vectren'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 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 ensure costs do not vary greatly across alternative future market conditions or supply disruptions.
- Environmental Emission Risk Mitigation: Provide environmentally responsible power, leading to a low carbon future.
- Market Risk Minimization: Develop a flexible plan that can adapt to market conditions and regulatory and technological change to minimize risk to Vectren

customers and shareholders. The plan considers several alternative options for existing resources.

Other Considerations

- Future Flexibility: Mitigate the risk that assets in the portfolio may become uneconomic in the future through off ramps and optionality.
- Resource Diversity: Mitigate risk to customers of over-reliance on a single technology by providing a mix resources 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

Reliability is Vectren's priority over all other objectives. While the IRP doesn't directly assess system stability issues, 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 metric tracked for each portfolio. Vectren did a reliability assessment for portfolios 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, Vectren illustrates tradeoffs among competing IRP objectives. This tool aided in the selection of the preferred portfolio. The last three objectives are more subjective in nature but relevant to the IRP process so are discussed under "other considerations". The following metrics were used to select the preferred portfolio:

Figure 2.2 – Vectren Scorecard for IRP Objectives and Risk Metrics

	Objective	Metric
Quantitative and Qualitative (considered outside of scorecard)	Reliability	• Reliability Assessment
Quantitative Scorecard Measure	Affordability	• Mean value for the 20-Year Net Present Value of Revenue Requirements (NPVRR) (million$) across 200 dispatch iterations under varying market conditions
	Cost Uncertainty Risk Minimization	• 95th percentile[11] of NPVRR (million$) across 200 dispatch iterations under varying market conditions
	Environmental Emissions	• Reduction in tons of life-cycle greenhouse gas emissions (CO_2e) 2019-2039
	Avoiding Overreliance on Market Risk	• Annual Energy Sales and Purchases, divided by Annual Generation, average (%) • Annual Capacity Sales and Purchases, divided by Total Resources, average (%)
Qualitative (considered outside of scorecard)	Resource Diversity	• Risk of overreliance on one type of resource
	System Flexibility	• Ability operationally to support the system to maintain stability and reliability
	Future Flexibility	• Risk that assets in a portfolio may become uneconomic

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 ensure that the ultimate choice of a portfolio performs well, regardless of the circumstances. Portfolio selection is based on Vectren 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 entirely derived from the probabilistic modeling. The probabilistic modeling subjected each portfolio to 200 iterations of the dispatch model under varying market conditions. Vectren 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 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 related transmission costs to deliver power to Vectren customers, plus 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.

2.3.2.2 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.

2.3.2.3 Environmental Emission Risk Minimization

For the Environmental Emission Risk Minimization objective, the metric estimated life cycle greenhouse gas emissions of each generation type, measured in tons of carbon dioxide equivalent (CO_2e). The use of life cycle emissions rather than direct generation emissions was a result of feedback from the stakeholder process. Life cycle emissions account for "cradle to grave" emission impacts of generation and offer more consistent comparisons of environmental impact across generation technologies. The lifecycle emissions captures upstream emissions including raw material extraction, power generation facility construction and any upstream emissions associated with fuel extraction and transportation (if applicable). Life cycle emissions were estimated using the National Renewable Energy Laboratory's (NREL's) harmonized life cycle emissions factors for generation technologies considered in the analysis.[12] Life cycle emissions from existing and new resources are derived by multiplying the generation from each fuel type (including coal, gas combustion turbine, gas combined cycle, utility-scale solar and solar distributed generation and onshore wind) by the corresponding specific technology

[12] NREL conducted a systematic review of 2,100 life cycle greenhouse gas emissions studies for electricity generating technologies and screened down the list to about 300 credible references. From these, NREL published the median values which were shared with IRP stakeholders and used to calculate life cycle greenhouse gas emissions for each portfolio.

emission factor. Emission factors for life cycle greenhouse gas emissions are presented in Figure 2.3.

Figure 2.3 – Life Cycle Greenhouse Gas Emission Factors (grams CO_2e/kWh)[13]

	Specific Technology	Market[14]
All Coal		1,002
Sub Critical	1,062	
Super Critical	863	
All Gas		474
Gas CT	599	
Gas CC[3]	481	
All Nuclear		16
Onshore Wind	12	12
All PV		54
Thin Film	35	
Crystalline	57	
All hydropower	7	7
Bio Power	43	43

To account for life cycle emissions from energy purchases imported from the market, Vectren used the MISO 2033 Futures energy utilization mix corresponding to the Accelerated Fleet Change mix from the 2019 MISO Transmission Expansion Planning Report (MTEP19)[15]. This estimation provides a figure of 347.4 grams of CO_2e/kWh as shown below in Figure 2.3a.

[13] Source: https://www.nrel.gov/analysis/life-cycle-assessment.html - Values derived from graphs included for each resource type. Note that battery storage was not estimated.
[14] Utilized when specific technology breakouts were not available within the MTEP study
[15] 2019 MISO Transmission Expansion Planning Report (MTEP19) https://www.misoenergy.org/planning/planning/mtep-2019-/

Figure 2.4 – MTEP19 Accelerated Fleet Change Mix Used to Calculate CO_2e Emissions from Energy Imports

Resource	Given Percentage in MTEP19 Fig. 2.5-2	Normalized Percentage	Grams of CO2e per kWh (NREL)	Pro Rata Grams of CO2e per kWh
Coal	18%	15.7%	1,002	156.8
Nuclear	6%	5.2%	16	0.8
CC/ST Gas	23%	20.0%	481	96.2
CT	16%	13.9%	599	83.3
Wind	30%	26.1%	12	3.1
Utility Solar	10%	8.7%	54	4.7
DG Solar	5%	4.3%	54	2.3
DR	4%	3.5%	0	0.0
Other	3%	2.6%	0	0.0
Battery	0%	0.0%	0	0.0
Total	115%	100.0%		347.4

Outside of the scorecard, Vectren 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.

2.3.2.4 Market Overreliance Risk Minimization

For the Market Overreliance Risk Minimization objective, there were four 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 total resources and expressed as a percentage.

Other Considerations

2.3.2.5 Uneconomic Asset Risk Mitigation

The recent generation order suggested that the consideration of future generation mix should include the risk that assets in the portfolio would become uneconomic due to technological advance. Vectren anticipated that the greatest risk would be imposed by capital intensive fossil plants as renewable assets became more economic with time.

To try to measure this risk, the probabilistic modeling provided an annual accounting of a plant's going-forward costs and revenues in each of the 200 iterations. In cases where the annual going-forward costs exceed the annual revenues for three consecutive years, the plant was deemed to be uneconomic[16] at that time. In the first year in which the plant was deemed uneconomic, the unamortized cost of the uneconomic asset and any additional losses in subsequent years was measured.

2.3.2.6 Resource Diversity Maximization

Vectren believes that 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. Vectren's coal units have served its customers well over the years, but continued pressure on this resource from environmental regulations, increasing use of intermittent renewable resources and low gas prices have resulted in several units having a low dispatch rate. The concentration of coal in Vectren's generation mix has become costly to Vectren customers over time. Additionally, the Indiana Commission reinforced this consideration in a recent Order that Vectren should consider resource diversity and alternatives that provide off ramps that allow Vectren to react to changing circumstances.

While very important, it is hard to create a measure that adequately captures this value. Instead, Vectren sought to develop a number of portfolios that included a wide range of resource types and fuel sources. To ensure this objective has been met, Vectren built portfolios that ensure diverse mixes. One way in which this has been done is that Vectren did not consider a large 2x1 Combined Cycle Gas Turbine (CCGT) in the 2019/2020 IRP. While potentially an economic solution for customers, moving from mostly coal to mostly gas was considered a risk in the long term due to the lack of

[16] Definition of an uneconomic asset: When going forward costs of the asset, which include annual variable costs (fuel + variable operations & maintenance or VOM + emissions) plus annual fixed operations & maintenance or FOM costs, are collectively greater than the total annual revenues (including both energy revenues and capacity revenues) in three successive years

flexibility to adjust to future conditions. Additionally, Vectren included an All-Source RFP to fully consider renewable resources within all portfolios.

2.3.2.7 System Flexibility

System flexibility was an important consideration in the 2019/2020 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, Vectren 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. Vectren also considers the transmission system and the ability to rely on the market as an important consideration in IRP planning. While Vectren has considerable import capabilities with the addition of the Duff Coleman Market Efficiency transmission Project (MEP) and the upcoming East/West line, this capability is not unlimited and requires needed upgrades to maintain reliability for portfolios that rely less on dispatchable energy resources.

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 Vectren selected a Reference Case and four alternative scenarios for two purposes. The first purpose was to select 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. Vectren 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:

- Vectren and MISO energy and demand (load)
- Henry Hub and delivered natural gas prices
- Illinois Basin mine and delivered coal prices
- National carbon (CO_2) prices
- Capital costs and associated cost curves for various supply side (generation) and demand side resource options

The long-term energy and demand forecast for the Vectren service territory was developed for Vectren by Itron, a leading forecasting consultant in the U.S. The forecast is based on historical residential, commercial and 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, Vectren used a "consensus" Reference Case view of expected prices by averaging forecasts from several sources. This helps to ensure that multiple views are considered and allows Vectren to be transparent with modeling assumptions. For natural gas and coal, 2019 forecasts from PIRA, Wood Mackenzie, Pace Global, ABB, and EVA were averaged. Based on a stakeholder request to include CO_2 in future years, Vectren decided to include a CO_2 price in the Reference case but not in the low regulatory case. The CO_2 forecast was developed by Pace Global. The capacity price forecast was based on MISO Zone 6 forecasts from Wood Mackenzie, Pace Global and ABB.

All-source RFP bids were utilized for resource cost information between 2022 and 2024, where possible. Long term cost curve information was developed utilizing a consensus approach, using Burns and McDonnell, NREL ATB and Pace Global. Burns & McDonnell

technology assessment helped fill in the gaps with operational data and for various traditional technologies like gas and coal resources.

Vectren 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.

Pace Global performed the production cost modeling used to create several key components of the IRP. Using the AURORAxmp power model, Pace Global developed an optimized, least-cost portfolio for the Reference Case, which was then run in chronological hourly dispatch mode. The deterministic dispatch run provided power price forecasts for MISO regions, as well as the least cost portfolios created utilizing the Reference Case. 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, Vectren, with the support of Pace Global, selected four alternative scenarios (a Low Regulatory, a High Regulatory, an 80% Carbon Reduction and a High Technology) 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).

Vectren worked with Pace Global and received input from Vectren stakeholders on key inputs such as load forecasts, gas and coal prices, carbon emission prices and technology capital costs. With input from stakeholders, Vectren and Pace Global determined whether gas prices, coal prices, load, technology capital costs, retirements/ builds, 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. This wide range of scenarios is bounded on one end by a Low Regulatory future with no CO_2 price. Regulation of CO_2 and other regulations ratcheted up moving towards the outer boundary condition, the High Regulatory future. Below is an illustrative description of each scenario.

- Low Regulatory – The primary carbon regulation is assumed to be the ACE rule. Indiana implements a lenient interpretation of the rule. ELG is partially repealed with bottom ash conversions not required for some smaller units and is delayed for two years (this does not apply to F.B. Culley 3). The limited regulation promotes a stronger economy, higher load and higher natural gas prices relative to the Reference Case. Other drivers still support declining coal demand over the planning horizon and as a result coal prices remain at levels similar to the Reference Case. Similarly, technology costs retain the same outlook as the Reference Case. This case is consistent with the theme that the Indiana Coal Council has consistently requested.

- High Technology – This scenario assumes that technology costs decline faster than in the Reference Case, allowing renewables and battery storage to be more competitive without significant regulation. A low carbon tax is ultimately implemented. The economic outlook is better than in the Reference Case as lower technology costs and lower energy prices offset the impact of the carbon tax. Increased demand for natural gas is more than met with advances in key technologies that unlock more shale gas, increasing supply and lowering gas prices relative to the Reference Case. Less demand for coal results in lower coal prices. Utility-sponsored energy efficiency costs rise early in the forecast but ultimately fall back to 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.

- 80% CO_2 Reduction by 2050 – This scenario assumes a carbon regulation mandating an ~80% reduction of CO_2 emissions from 2005 levels by 2050 is implemented. A gradually declining carbon cap drives carbon allowance costs up over time. Load decreases as the costs for energy and backup power increase and as the energy mix transitions. Natural gas prices remain at similar levels to the Reference Case as the impact of methane regulation is offset by lower demand and productivity increases that lower supply costs. Coal demand declines over time. Renewables and battery storage technologies are widely implemented to help meet the mandated CO_2 reductions. Despite this demand, costs are lower than the Reference Case due to subsidies or similar public support to address climate change concerns.

- 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 set at the social cost of carbon is implemented early in the planning horizon (2022). Monthly rebate checks (dividend) redistribute revenues from the tax to American households based on number of people in the household. 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 results in coal prices lower relative to the Reference Case. With the higher costs, innovation occurs as renewables and battery storage are widely implemented to avoid paying high carbon prices, 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.

A summary of the relative outlooks for key market drivers across the scenarios considered is presented in Figure 2.5.

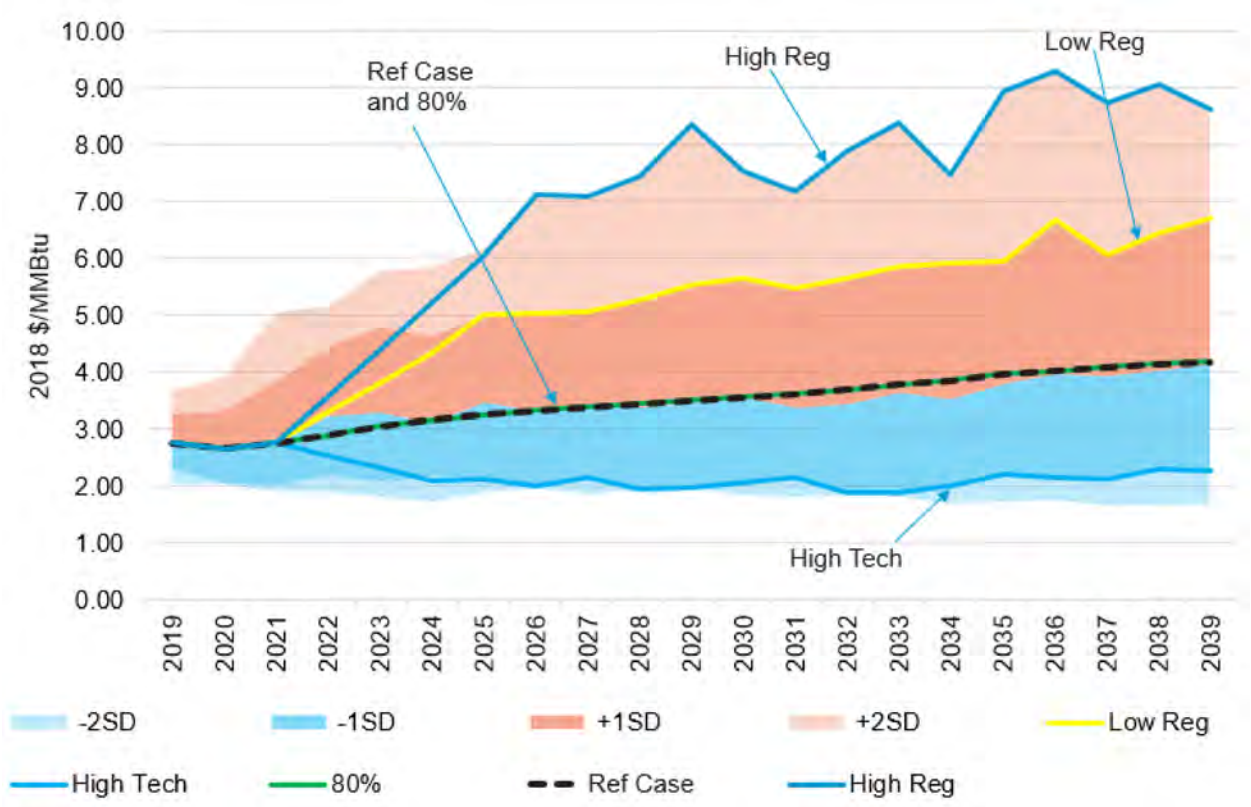
Figure 2.5 – Summary of Directional Relationships of Key Inputs Across Scenarios

	CO_2	Gas Reg.	Water Reg.	Economy	Load	Gas Price	Coal Price	Renewables and Storage Cost	EE Cost
Reference Case	ACE Replaced with CO_2 Tax	none	ELG	Base	Base	Base	Base	Base	Base
Low Regulatory	ACE	none	ELG Light*	Higher	Higher	Higher	Base	Base	Base
High Technology	Low CO_2 Tax	none	ELG	Higher	Higher	Lower	Lower	Lower	Lower
80% CO_2 Reduction by 2050	CO_2 Cap	Methane	ELG	Lower	Lower	Base	Lower	Lower	Higher
High Regulatory	High CO_2 Tax w/ Dividend	Fracking Ban	ELG	Base	Base	Highest (+2 SD)	Lower	Lower	Higher

*No bottom ash conversion required based on size of the unit and delay requirement for 2 years. Does not apply to Culley 3

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 (2019-2021). In the medium-term (2022-2028), key variables grow or decline to +/-1SD or (+/-2SD) by 2025 (midpoint of medium-term) as shown in the table above. After 2025, the variable stays at +/-1SD (or +/-2SD) into the long-term to 2039. Because this price path remains at the one (or two) standard deviation(s) path for the entire planning horizon, these levels have 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 2.6

Figure 2.6 – Henry Hub Natural Gas Price Scenarios (2018$/MMBtu)



All gas prices begin at $2.77/MMBtu in 2019, dip slightly in 2020 and rise back to $2.76/MMBtu in 2021. After this time, the Reference Case gas prices gradually trend upward to $4.17/MMBtu in 2039. 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 standard deviation 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 last seen prior to 2008 before the shale boom era began. The High-Tech scenario sees natural gas prices moving downward to -1 standard deviation below the Reference Case.

The convention of +/-1 standard deviation 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 standard deviations above the historical average, whereas they typically cannot fall below zero (or approximately two standard deviations below the historical average).

Note that the selection of one standard deviation up in every year of the study means that the actual price in any one year may exceed that value 15.8% of the time, but over the entire 20 year planning horizon only about 5-7% of the time the price will exceed the price on the curve. Selecting a 2 standard deviation change, as was done for gas prices, means that only 2.2% of the time the price in any one year will exceed the value selected and over the 20-year planning horizon; the chances of a higher average price is less than 1 percent.

The graphical descriptions of values for each of the key metrics (e.g. load, gas prices, coal prices, technology costs, carbon prices and power prices) 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.

A Burns & McDonnell 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 were based on consensus estimates from three sources. These long-term cost estimates were averaged with outlooks from Pace Global and NREL to form the consensus technology

cost projections over the planning horizon. 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, landfill gas, several battery storage options, simple cycle and combined cycle natural gas and natural gas fired combined heat and power technologies. Note that Aeroderivative turbines and gas reciprocal engines were excluded based on the cost per KW and high gas pressure needed to run them. Two new coal-fired technologies were included, both of which were assumed to be equipped with carbon capture and storage.

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 Burns & McDonnell and ultimately converted into model inputs.

Long Term Capacity Expansion (LTCE) Assessments

The AURORAxmp power model (Aurora) was used as the central tool in the IRP to develop the 14 candidate portfolios in addition to the Reference Case portfolio. The long-term capacity expansion functionality within Aurora was used to develop least cost optimized portfolios based on the given sets of market input assumptions and portfolio requirements. This includes decisions to build, purchase, or retire plants.

Market transactions offer supply flexibility but also exposure to potential market risk to Vectren 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 approximately ~15% of capacity needs, or 180 MW, was defined for annual capacity market purchases (except in a transitional year). This is much more than the 2016 IRP where a 10 MW cap was utilized and is responsive

to the Commission Order 45052, which said Vectren did not fully consider energy or capacity purchases.

Portfolios were selected in a few different ways.

- Least cost portfolios were developed for the Reference Case and the other market and regulatory scenarios (5 Portfolios)
- Least cost portfolios with some modifications to existing units
- Stakeholder driven least cost portfolios

Portfolios were developed utilizing AURORA's LTCE modeling for the Reference Case and the four alternate scenarios. The model uses hourly chronological dispatch over a 20-year period, which means that 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.

In addition, alternative portfolios were developed by Vectren and based on stakeholder input to specifically test alternate resource strategies. These include the following additional 10 resource portfolios:

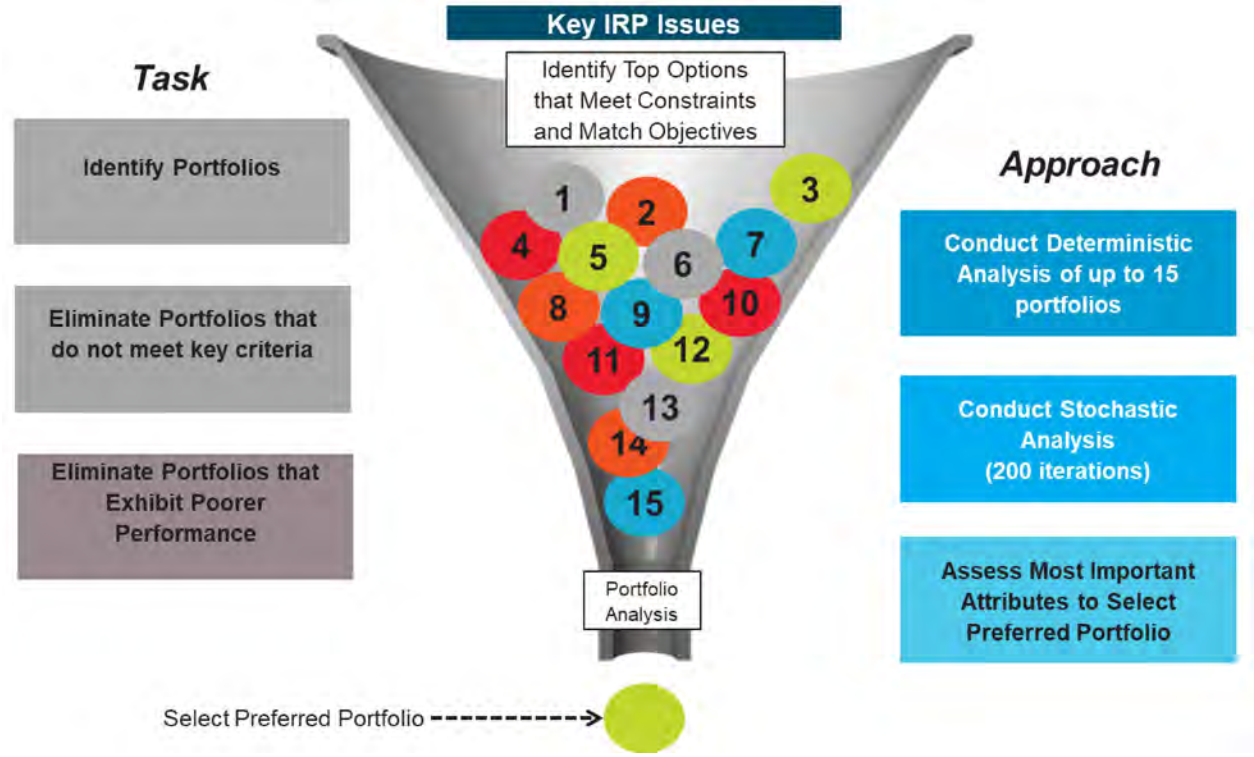
1. Business as usual to 2039 including the continued operation of all existing units (joint operations of Warrick 4 ends by 2024);
2. Bridge with business as usual to 2029, including the continued operation of A.B. Brown units 1 & 2 through 2029;
3. Bridge in which A.B. Brown 1 is converted to natural gas;
4. Bridge in which both A.B. Brown 1 and 2 are converted to natural gas;
5. Bridge in which A.B. Brown 1 is converted to natural gas and a CCGT is added;
6. Diverse energy portfolio including a new small (443 MW) natural gas CCGT;
7. Diverse energy portfolio including a new medium (511 MW) natural gas CCGT;
8. Renewables portfolio utilizing a combination of renewables, storage and peaking natural gas;

9. Renewables portfolio with no fossil technology options allowed in the portfolio by 2030; and
10. Portfolio based on HB 763 CO_2 price, which reaches $200/ton by the end of the study period.

In each of these LTCE assessments, the refinement for each portfolio, whether it be a modification to an existing unit or requiring the addition of a CCGT as a minimum requirement was required as part of a portfolio and then the model selected the remainder of the portfolio on a least cost basis.
Figure 2.7 – Structured Portfolio Selection Process illustrates the portfolio screening process applied in the analysis to select the preferred portfolio.

As described in Section 8, Vectren selected 10 of the 15 least cost portfolios for evaluation in the risk analysis. The selection criteria for eliminating the five portfolios are provided in that section.

Figure 2.7 – Structured Portfolio Selection Process



2.6 PORTFOLIO PERFORMANCE (SCENARIO BASED RISK ASSESSMENT)

The framework of the Indiana law mandating a triennial IRP[17] 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 (Low Regulatory, High Technology, 80% Reduction of CO_2 and High Regulatory), 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.

AURORA is run in a market simulation mode holding each of the Vectren portfolios constant but allowing other MISO members to modify its decisions on the basis of the Scenario selected. The results of the scenario-based risk analysis are summarized in Section 8.2.1.

2.7 PORTFOLIO PERFORMANCE (PROBABILISTIC OR 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 coal prices, natural gas prices, carbon prices, peak and average load (at the Vectren, MISO Local Resource Zone 6 (LRZ6) and MISO levels) and capital costs for a range of technologies. Each of these stochastic variables is propagated to the end of the study period, typically 1,000 to 3,000 times. A stratified sampling of the runs is taken, which allows the sample set to be reduced to 200 iterations. These 200 iterations of each stochastic variable are

[17] Indiana Code § 8-1-8.5

then loaded as inputs into the dispatch model. These inputs thus allow for the testing of each portfolio's performance across a wide range of market conditions.

Once again, all 10 portfolios were subjected to each of the 200 iterations (scenarios) using AURORA in dispatch mode where the Vectren portfolio is fixed but other MISO members can make decisions under each market scenario.

2.8 SENSITIVITY ANALYSIS

Vectren conducted several sensitivities in order to put brackets around resulting portfolios when one or more variables were adjusted. Sensitivities were also conducted to ensure seasonal Planning Reserve Margin (PRM) targets are met and that the candidate portfolio buildouts are calibrated to the greatest annual constraint, which occurs in the summer peak period.

- Vectren ran sensitivities to compare portfolio buildouts with winter solar/wind peak capacity credit on winter peak demand versus portfolio buildouts with summer solar/wind peak capacity credit on summer peak demand. Portfolios that are overly reliant on solar generation may risk not meeting MISO Planning Reserve Margin Requirements in the winter, as rules continue to evolve.
- Vectren performed sensitivities using a seasonal PRM target and seasonal peak capacity accreditation (solving to monthly peak hour). This sensitivity resulted in a solar peak capacity credit that approached zero as the Vectren system approached 2,000+ MW solar.
- Vectren performed a sensitivity in which the cost of a solar PPA resources increases 30%, based on more recent market information. The sensitivity demonstrated that even with increased costs, the solar PPA costs remain below the market clearing on-peak price of $42-45/MWh and continue to be selected as economic portfolio additions.
- Vectren conducted sensitivities to right-size several portfolios that had more capacity than needed in the early years of the transition from the point of view of the PRM target, but the model selects several early resources to capture the

benefits of the wind Production Tax Credit and solar Investment Tax Credit. Early solar and wind resources help to lower total cost of each portfolio.

- Sensitivities were run on the Reference Case and High Technology portfolios, swapping combustion turbine capacity for storage capacity. Portfolio costs rose as a result, but costs can vary widely depending on whether augmentation (replace dead battery cells) and other costs are fully incorporated into the bid price.
- A sensitivity was run on the Reference Case to assess 1.25% energy efficiency (EE) in the near-term as compared to the selected 0.75% EE in the near-term, which raised portfolio costs by 0.15%. As such, 1.25% was included in all portfolios for the first 3 years.

2.9 BALANCED SCORECARD

The Risk Analysis (based on the probabilistic modeling) of each of the portfolios was developed by Pace Global using the AURORAxmp 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. This was done by considering volatility of each factor in the short-term, medium-term and long-term.
- 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 inputs development.
- Each candidate portfolio was then run through simulated dispatch for the 200 possible future states using the AURORAxmp production cost model. AURORAxmp dispatches the candidate portfolio for each sampled hour over the

planning horizon. For this risk analysis procedure, AURORAxmp assumes that each Vectren candidate portfolio is constant but allows for builds and retirements to occur throughout the region based on economic criteria. Vectren generation, costs, emissions, revenues, etc. are tracked for each iteration over time.

- Next, values for each metric are tracked across all 200 iterations and presented as a distribution with a mean, standard deviation and other metrics as needed.
- 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 flexibility. To help illustrate tradeoffs, Vectren used a Balanced Scorecard, as shown below in Figure 2.8 and further discussed in Section 8.

Figure 2.8 – Balanced Scorecard Illustration

Balanced Scorecard		Objective	Affordability	Price Risk Minimization	Environmental Risk Minimization	Market Risk Minimization		Market Risk Minimization	
		Metric	20-Year NPVRR ($million)	95th percentile NPVRR ($million)	Life Cycle GHG Emissions (million tons CO2e reduction 2019-2039)	Energy Market Purchases & Sales (% of generation)		Capacity Market Purchases & Sales (% of peak demand)	
No	Group	Candidate Portfolio				Purch	Sale	Purch	Sale
1	Reference	Reference Case							
2	BAU	BAU to 2039							
3		BAU to 2029							
4	Bridge	ABB1 gas conversion							
5		ABB1+ABB2 gas conversions							
6		ABB1 gas conversion + CCGT							
7	Diverse	Diverse Small CCGT							
8	Renewables	Renewables+ Flexible Gas							
9		Renewables 2030							
10	Scenario	High Technology							

The preferred portfolio represents Vectren'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

Vectren reevaluated how to conduct the stakeholder process based on comments in the Director's report, stakeholder feedback and the Commission order in Cause number 45052. Careful consideration was given to improve the process. 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, Vectren'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 Vectren and the electric utility industry
- **Consider**: Provide a forum for relevant, timely stakeholder feedback at key points in the Integrated Resource Plan process to inform Vectren's decision making

IRP stakeholders include, but are not limited to, Vectren residential, commercial and industrial customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers and advocacy groups, shareholders and elected officials.

In the first public stakeholder meeting, Vectren publicly made 12 commitments and followed through with all throughout the process:

1. To strive to make every encounter meaningful for stakeholders and for us
2. To provide a data release schedule and provide modeling data ahead of filing for evaluation
3. That the IRP process informs the selection of the preferred portfolio
4. To utilize an All-Source RFP to gather market pricing & availability data
5. To use one model for consistency in optimization, simulated dispatch and probabilistic functions
6. To attempt to model more resources simultaneously

7. To include a balanced, less qualitative risk score card
8. To work with stakeholders on portfolio development
9. To test a wide range of portfolios in scenario modeling and ultimately in the risk analysis
10. To conduct a sensitivity analysis
11. To take an exhaustive look at existing resource options
12. That the IRP will include information presented for multiple audiences (technical and non-technical)

The first three stakeholder meetings began with stakeholder feedback. Vectren would review all requests since the last stakeholder meeting and provide feedback. Often suggestions were incorporated, but in instances where suggestions were not. Vectren made a point to discuss further and explain why not. Per stakeholder feedback, 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 phone calls/meetings in between each session per request. The final meeting was a preview of the preferred portfolio and a discussion of analysis. Due to COVID, this meeting was held via webinar.

The first three public stakeholder meetings were held at Vectren headquarters in Evansville, IN. Dates and topics covered are listed below:

Figure 3.1 – 2019/2020 Stakeholder Meetings

August 15, 2019	October 10, 2019	December 13, 2019	June 15, 2020
• 2019/2020 IRP Process • Objectives and Measures • All-Source RFP • Environmental Update • Draft Reference Case Market Inputs & Scenarios	• RFP Update • Draft Resource Costs • Sales and Demand Forecast • DSM MPS/ Modeling Inputs • Scenario Modeling Inputs • Portfolio Development	• Draft Portfolios • Draft Reference Case Modeling Results • All-Source RFP Results and Final Modeling Inputs • Scenario Testing and Probabilistic Modeling Approach and Assumptions	• 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.vectren.com/irp and in Technical Appendix Attachment 3.1 Stakeholder Materials.

3.2 KEY ISSUES DISCUSSED

Throughout the process Vectren engaged stakeholders on all key inputs into the IRP, which helped shape the outcome of the analysis. In the first stakeholder meeting, Vectren presented a draft balanced scorecard which was used to evaluate key tradeoffs among portfolios. Adjustments were made and presented to stakeholders before modeling commenced. Vectren worked closely with stakeholders to develop scenario concepts and helped to refine various scenario inputs. Additionally, stakeholders provided input into portfolio development, which helped to provide a wide range of portfolios, included continuation of the Brown coal units through 2029 or 2039 and an all renewables portfolio by 2030.

3.3 STAKEHOLDER INPUT

During the 2019/2020 IRP, stakeholders provided their input in several ways: 1) verbal feedback through question/answer sessions during public stakeholder meetings; 2) through participation in Vectren stakeholder workshops; 3) via written feedback/requests; 4) telephone conversations; and 5) meetings between stakeholder sessions.

Vectren worked diligently to have an open forum for stakeholders to voice questions/concerns and make suggestions on the IRP analysis. Each Vectren stakeholder meeting was opened by Lynnae Wilson, Chief Business Officer for Indiana Electric. She and other senior management, Vectren subject matter experts and expert consultants actively participated in each meeting to help address stakeholder questions/concerns.

Below is a summary of key feedback during the 2019/2020 IRP that heavily influenced the analysis. For a full list, see the technical appendix Technical Appendix Attachment 3.1 Stakeholder Materials.

Figure 3.2 – Summary of Key Stakeholder Input

Request	Response
Update the High Regulatory scenario to include a carbon fee and dividend	Included a fee and dividend construct which assumed less impact on the economy/load
Lower renewables costs in the High Regulatory and 80% CO_2 Reduction scenarios	Updated scenario to include lower costs for renewables and storage than the Reference scenario
Consider life cycle emissions using CO_2 equivalent	Included a quantitative measure on the risk scorecard based on National Renewables Energy Laboratory (NREL) Life Cycle

Request	Response
	Greenhouse Gas Emissions (CO_2e) from Electricity Generation by Resource
Include a measure within the risk score card that considers sunk costs	Vectren worked with Pace Global to create an uneconomic asset risk measure. Ultimately, this measure was considered but not included within the scorecard, it did not fulfil the initial intention, to evaluate risk of resources with large initial capital investments
Include a scenario with a carbon dividend modeled after HB 763 with a CO_2 price curve that was approximately $200 by the end of the forecast	Ran a sensitivity to create a portfolio. Ultimately, this was not selected for the risk analysis, as the amount of generation built within modeling vastly exceeded Vectren's need
Reconsider the use of a seasonal construct for MISO resource accreditation	Reviewed calculation for solar accreditation in winter and utilized an alternate methodology, increasing accreditation in the winter
Include a CO_2 price in the reference case	Included a mid-range CO_2 price curve 8 years into the forecast. The low regulatory scenario did not include a CO_2 price, and remains a boundary condition

3.4 DATA REQUESTS SUMMARY

One of the key data requests made was to provide access to all-source RFP bids. While protecting confidentiality commitments to bidders' competitively sensitive information, Vectren provided two consumer groups (OUCC and CAC) who signed a NDA with electronic read-only access via a locked down SharePoint site. A data key was provided

for convenience to show the difference between tier one and tier two bids and many attributes of each bid. Additionally, Vectren received a data request from the CAC on December 9, 2019. Per their request, Vectren provided wind and solar resource shape files, input files utilized in the load forecast for regression modeling along with documentation, probabilistic modeling distributions for natural gas, capital cost, carbon price and peak load and costs associated with the retirement of existing thermal units.

CAC also requested modeling files as a part of their review process, prior to filing the IRP. In order to accommodate this request, Vectren worked with them to provide files to the OUCC and CAC on May 15, 2020 in preparation for the final stakeholder meeting on June 15th. Vectren held a discussion with these stakeholders on May 26th to answer questions and walk them through the file formats. Vectren worked to answer questions leading into and after the final IRP stakeholder meeting.

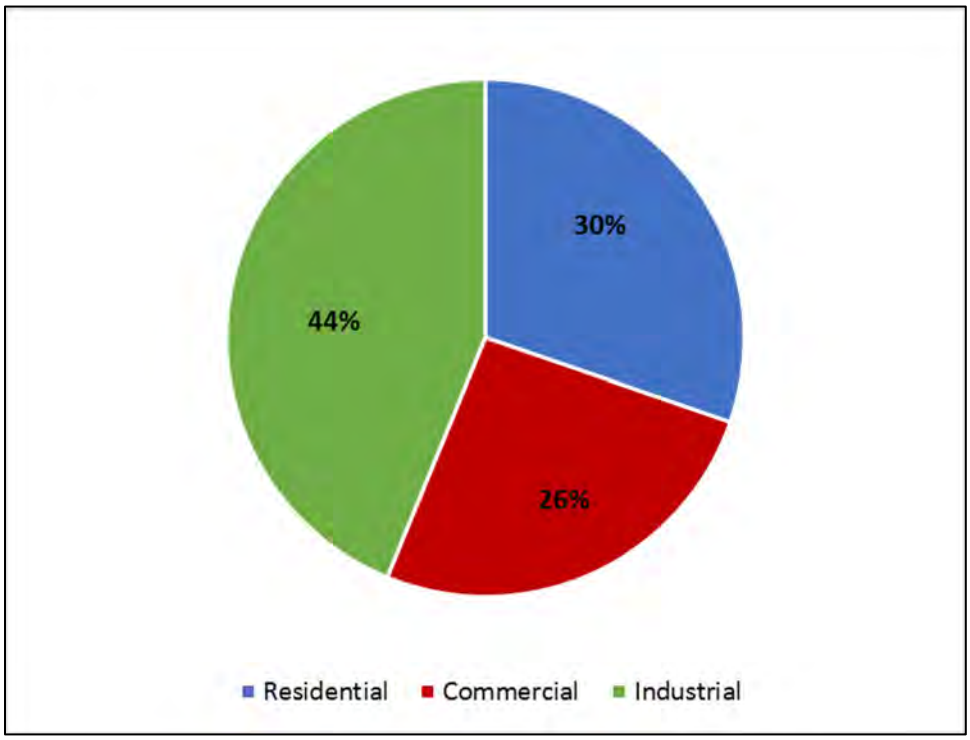
CAC also issued Data Request 2 on 6-5-20, Data Request 3 on 6-10-20 and Data Request 4 on 6-11-20. Vectren provided responses ahead of the required timeframe and before the filing of the IRP.

SECTION 4
CUSTOMER ENERGY NEEDS

4.1 CUSTOMER TYPES

Vectren serves more than 146,000 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 44% of energy sales in 2018. The residential class accounts for 30% of sales with approximately 128,000 customers and the commercial class 26% of sales; there are approximately 18,000 nonresidential customers. System 2018 energy requirements were 5,308 GWh with non-weather normalized system peak reaching 1,039.2 MW. Figure 4.1 shows 2018 class-level sales distribution.

Figure 4.1 – 2018 Vectren 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 over ten years of historical energy and demand data within the energy and demand forecasts. This data is maintained by Vectren 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 Moody's Economy.com, 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. Vectren's peak demand is typically in summer when temperatures are hottest. Air conditioning drives summer usage. Normal weather data is obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. Vectren utilizes data over a 20-year period for the sales forecast and a 20-year period for the demand forecast in order to capture recent weather activity.

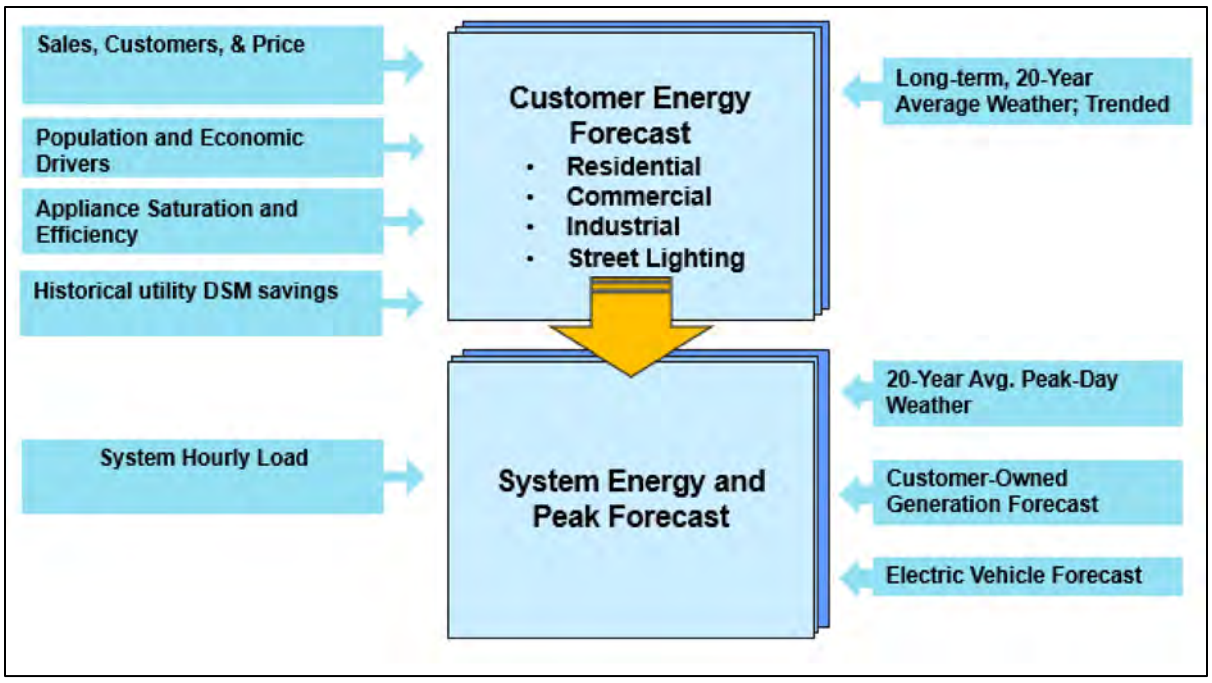
Itron, Inc. provides regional Energy Information Administration (EIA) historic and projected data for equipment efficiencies and market shares. This data captures projected changes in equipment efficiencies based on known codes and standards and market share projections over the forecast period, including 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 Vectren'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 Vectren'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 Vectren'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 over)

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 Vectren. Conversely, when a DG system produces more power than the customer's load, excess power can be sent back to Vectren's electric system through a program called net metering. The customer is charged the retail rate for the net power that they consume.

4.4.1 Current DG

As of December 2019, Vectren had approximately 486 residential solar customers and 71 commercial solar customers, with an approximate installed capacity of 10.7 MW. Based on recent solar installation data, the residential average size is 10.5 KW, while the commercial average system size is 78.7 KW. Vectren has incorporated a forecast of customer owned photovoltaic systems into the sales and demand forecast.

Vectren 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 Vectren'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.

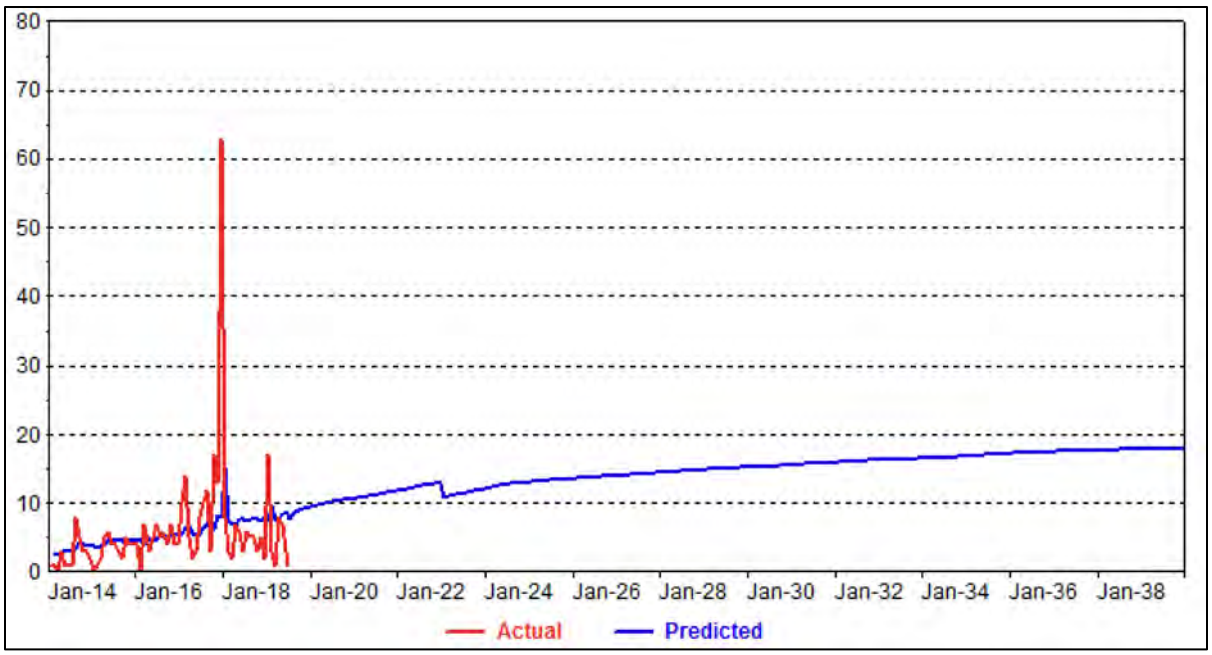
The primary factor driving system adoption is a customer's return-on-investment. Itron created a simple payback model, which was used as proxy. Simple payback reflects the length of time needed to recover the cost of installing a solar system - the shorter the payback, the higher the system adoption 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). Currently, excess generation is credited at the customer's retail rate. While current net metering customers will be credited the retail rate, DG installed beyond 2021 will be credited at the wholesale cost plus 25%.

One of the most significant factors driving adoption is declining system costs, which have been declining rapidly over the last several years. In 2010, residential solar system cost was approximately $7.00 per watt. By 2017 costs had dropped to $3.70 per watt. For the forecast period, Itron assumed system costs will continue to decline 10% annually through 2024 and an additional 3% annually after 2024. Customer owned solar cost projections are consistent with the U.S. Dept. of Energy's Sun Shot Solar goals and national trends.

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

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, installed capacity of solar is expected to increase at a compound annual growth rate of 10.9% with 84.3 MWs by 2039.

Figure 4.4 – Solar Capacity and Generation

Year	Total Generation MWh	Installed Capacity (Aug) MW	Demand Impact MW
2019	20,144	9.3	2.7
2020	23,260	11.8	3.5
2021	26,856	14.6	4.3
2022	30,834	17.6	5.2
2023	34,842	20.7	6.1
2024	38,999	23.8	7.0
2025	43,290	27.1	8.0
2026	47,880	30.6	9.0
2027	52,577	34.2	10.1
2028	57,535	37.9	11.2
2029	62,462	41.7	12.3
2030	67,499	45.6	13.4
2031	72,742	49.6	14.6
2032	78,272	53.6	15.8
2033	83,492	57.7	17.0
2034	89,074	62.0	18.3
2035	94,787	66.3	19.5
2036	100,707	70.6	20.8
2037	106,394	75.1	22.1
2038	112,446	79.7	23.5
2039	118,499	84.3	24.8
CAGR 2020-2039	8.9%	10.9%	10.9%

4.4.3 Potential Effects of Distributed Generation on Transmission and Distribution

Distributed Generation customers currently affect a small amount of load on each respective distribution circuit, which has not caused significant operational issues for Vectren. At higher levels of DG penetration, Vectren 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** – Vectren'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 Vectren incurs to provide retail electric service. DG customers (who generate a portion of their own electricity but still rely on the electric grid) avoid paying towards the recovery of the fixed costs of the grid that are recovered through the energy charge, which leads to Vectren'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.

- **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, Vectren estimated 238 registered electric vehicles were in the counties that Vectren 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 Vectren serves. Vectren purchases quarterly from the BMV a list of vehicle registrations for the counties that Vectren serves.

4.5.2 EV Forecast

As electric vehicles are gaining more traction in the vehicle market, Vectren decided to include an electric vehicle forecast in the 2019/2020 IRP. As described in the 2019 Long-Term Electric Energy and Demand Forecast Report in the Technical Appendix of this IRP, Itron created an electric vehicle forecast utilizing the Energy Information Administration (EIA) Annual Energy Outlook (AEO) transportation forecast to estimate the number of cars per household over time. This number is multiplied by the forecast of residential customers to create a projected number of vehicles per Vectren household. Itron then applied the EIA AEO projected saturation of battery electric vehicles and plug in hybrid electric vehicles.

Electric vehicles' impact on Vectren's load forecast depends on the amount of energy a vehicle consumes annually and the timing of vehicle charging. BEVs consume more electricity than PHEVs 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 Vectren'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 Vectren 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. Table 4.5 shows the electric vehicle forecast.

Figure 4.5 – Electric Vehicle Load Forecast

Year	BEV MWh	PHEV MWh	Total EV MWh	Demand Impact MW (Aug)	Demand Impact MW (Jan)
2019	432	305	737	0.1	0.1
2020	1,063	580	1,643	0.2	0.1
2021	2,667	1,110	3,777	0.4	0.3
2022	6,691	2,124	8,815	1.0	0.6
2023	14,769	3,732	18,501	2.1	1.4
2024	19,178	4,503	23,681	2.5	2.2
2025	22,770	5,106	27,876	2.9	2.7
2026	26,320	5,697	32,017	3.3	3.1
2027	29,838	6,275	36,113	3.8	3.5
2028	33,334	6,837	40,171	4.2	3.9
2029	36,869	7,392	44,261	4.6	4.3
2030	40,467	7,933	48,400	5.0	4.8
2031	44,164	8,455	52,619	5.5	5.2
2032	47,920	8,959	56,878	5.9	5.6
2033	51,735	9,438	61,173	6.3	6.1
2034	55,591	9,895	65,486	6.8	6.5
2035	59,461	10,327	69,788	7.2	7.0
2036	63,315	10,741	74,056	7.7	7.4
2037	67,111	11,137	78,248	8.1	7.8
2038	70,863	11,510	82,373	8.5	8.3
2039	74,607	11,872	86,479	8.9	8.7
CAGR 2020-2039	25.1%	17.2%	23.2%	22.7%	25.7%

4.5.3 Potential Effects on Generation, Transmission and Distribution

Electric Vehicles and their associated charging stations currently have a minimal impact on the Vectren electric system and therefore have not caused significant operational issues. As the level of EV charging stations increases, Vectren 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 that 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 that 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 0.6% annual growth over the next 20 years. The table below shows Vectren'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 Vectren long-term energy and demand forecasts, including load shapes, see Technical Appendix Attachment 4.1 2019 Vectren Long-Term Electric Energy and Demand Forecast Report.

Figure 4.6 – Energy and Demand Forecast[18]

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2019	5,147,837		1,115		826	
2020	5,374,079	4.4%	1,100	-1.4%	831	0.6%
2021	5,380,877	0.1%	1,102	0.2%	828	-0.3%
2022	5,505,660	2.3%	1,126	2.2%	847	2.3%
2023	5,742,090	4.3%	1,168	3.7%	886	4.6%
2024	5,774,656	0.6%	1,173	0.5%	891	0.5%
2025	5,789,928	0.3%	1,176	0.3%	891	0.1%
2026	5,807,569	0.3%	1,179	0.3%	892	0.1%
2027	5,828,395	0.4%	1,183	0.3%	894	0.2%
2028	5,858,975	0.5%	1,189	0.5%	898	0.4%
2029	5,874,831	0.3%	1,192	0.3%	898	0.1%
2030	5,891,575	0.3%	1,196	0.3%	899	0.1%
2031	5,909,760	0.3%	1,200	0.3%	900	0.1%
2032	5,934,963	0.4%	1,205	0.4%	902	0.3%
2033	5,949,314	0.2%	1,209	0.3%	902	0.0%
2034	5,970,284	0.4%	1,214	0.4%	903	0.1%
2035	5,992,643	0.4%	1,219	0.4%	905	0.2%
2036	6,019,773	0.5%	1,225	0.5%	907	0.3%
2037	6,034,306	0.2%	1,229	0.4%	907	0.0%
2038	6,053,929	0.3%	1,234	0.4%	908	0.1%
2039	6,072,712	0.3%	1,239	0.4%	909	0.1%
CAGR 2020-2039		0.6%		0.6%		0.5%

4.7 DISCUSSION OF BASE LOAD, INTERMEDIATE LOAD and PEAK LOAD

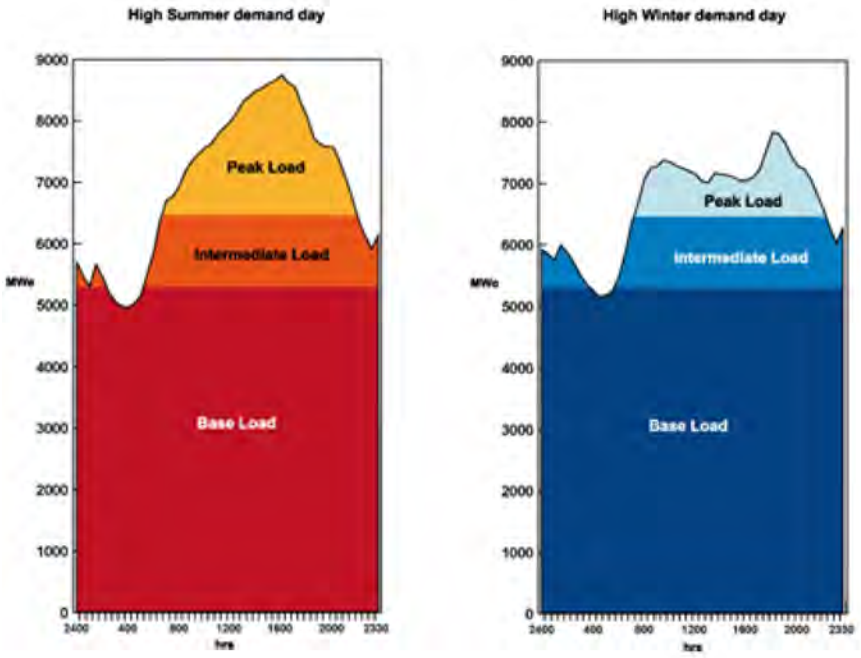
There are three levels of electric load: base load, intermediate load and peak load. Base load is the minimum level of demand on an electrical supply system over 24 hours. Base load is primarily served by power plants which can generate consistent and dependable power. Intermediate load is a medium level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

[18] 2019/2020 IRP energy and demand forecast provided to MISO in Nov. 2019 differed slightly in order to match MISO's requirements which necessitated the following an adjustment. It incorporated the 2016 IRP's preferred level of DSM

peak hour is typically between June and September, when weather is hottest. For modeling purposes, Vectren 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

Vectren discussed the load forecast with stakeholders in the October 10th stakeholder meeting, providing an opportunity to provide input, question and comment on the draft load forecast before finalizing. There was a robust discussion on trended weather projections used in the load forecast. Some stakeholders believed that the trend utilized did not reflect the findings in a recent Purdue University climate study. Vectren reached out to Purdue University and they provided some clarification on the differences between their study and ours, including using different set points for heating and cooling degree days. Itron reviewed and estimated that the HDD trend was the same, while the CDD trend is nearly two times higher in the Purdue dataset. Utilizing the Purdue CDD trend would add approximately 40 MWs to Vectren's forecast over the next 20 years, which was well within Vectren's high bound forecast. Vectren did not update its load forecast, based on this analysis. This was discussed in the December 13, 2020 stakeholder meeting.

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 Vectren is a member. MISO oversees power delivery across 15 states and the Canadian province of Manitoba and is the largest energy and operating reserves market in the world. MISO is divided into 11 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), approximately 70% of Vectren'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 Vectren and its other member electric utilities to maintain a Planning Reserve Margin Requirement (PRMR). The PRMR is the amount of resources MISO requires in order to meet a NERC standard of one loss of load event in ten years and is designed to ensure there is enough power capacity throughout the MISO region to meet customer demands during peak periods, including peak periods where some equipment might fail. To further ensure the NERC standard of one loss of load event in ten years, the PRMR is further detailed by the Local Clearing Requirement (LCR) which mandates how much of a Local Resource Zone's (LRZ) PRMR must be met by generation resources physically located within that LRZ. 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 appears to continue as some baseload units are projected to retire by 2023. As a result, long term dependence on the market for capacity and energy has considerable risk.

The illustration below shows the load on a typical day and load on the peak day with the reserve margin requirement.

Figure 5.2 –Illustration of Load Curve and Planning Reserve Margin

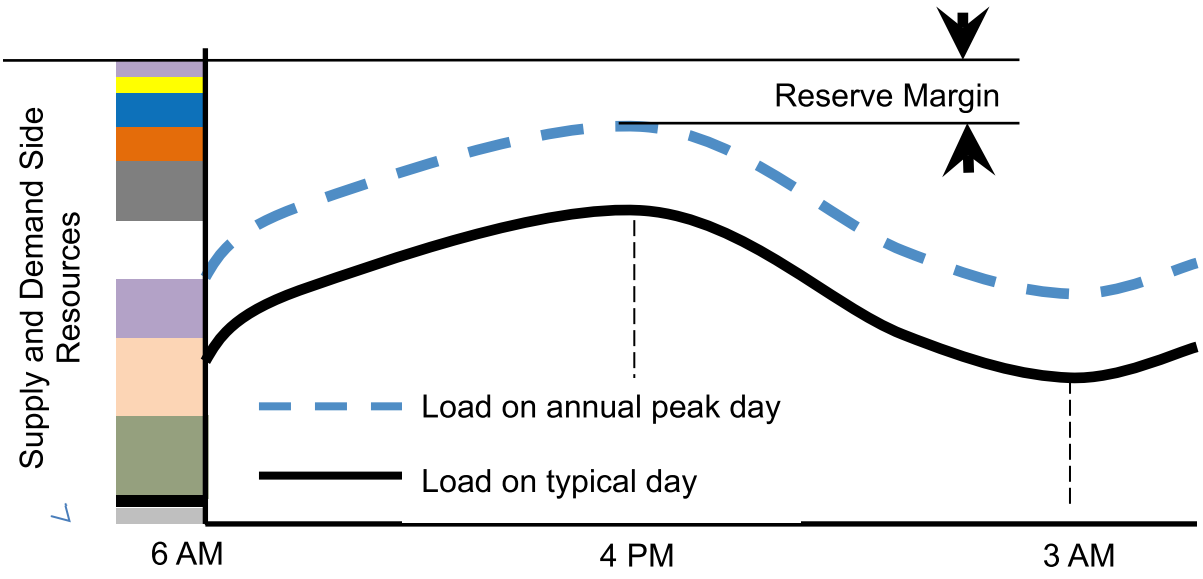


Figure 5.3 –Historic MISO PRMR

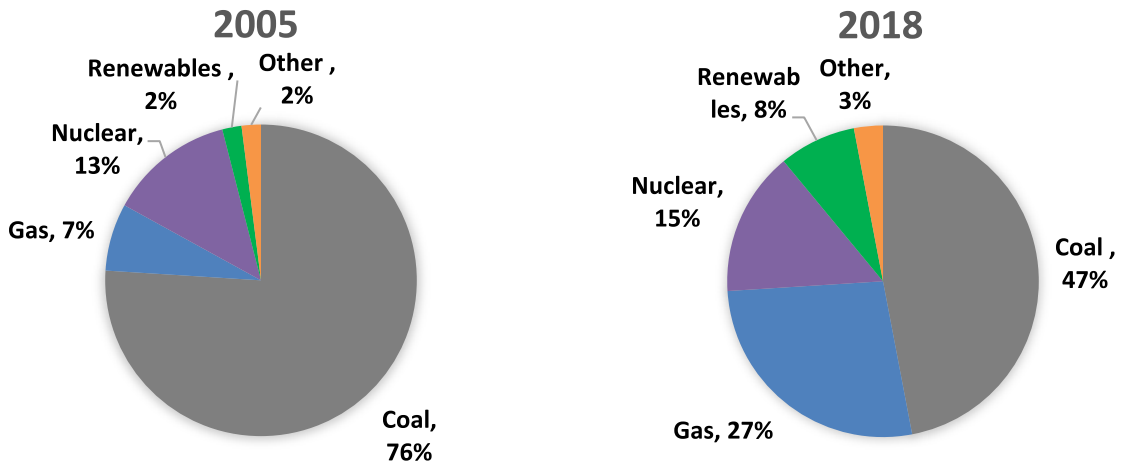
Planning Year	MISO PRMR (UCAP)-Required	MISO PRM (UCAP)-Excess Available: Offered/PRMR
2020-21	8.90%	142,082/135,960: 4.50%
2019-20	7.90%	142,082/134,743: 5.45%
2018-19	8.40%	141,781/135,179: 4.88%
2017-18	7.80%	142,146/134,753: 5.49%
2016-17	7.60%	141,524/135,483: 4.46%
2015-16	7.10%	145,861/136,359: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

5.3 MISO Resource Mix – Past, Current and Future

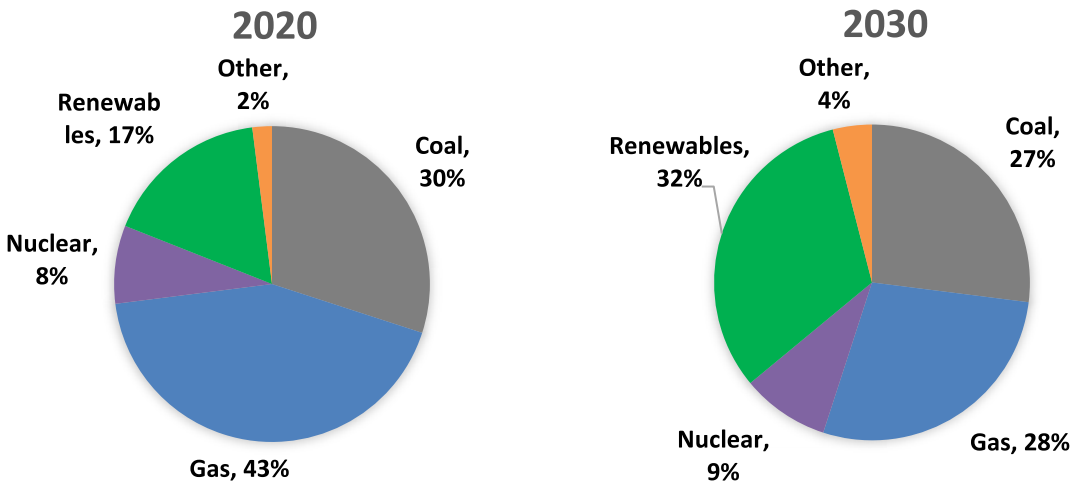
MISO's resource fuel mix has changed drastically since its market inception in 2005. In 2005, coal was the predominant fuel source, with MISO lacking diversity and nuclear as the closest competitor at 13%. In 2018, after the implementation of the Clean Power Plan and various other regulations and due to 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. This year natural gas (43%) is the leading fuel source in MISO, followed by coal (30%) and renewables (17%), while nuclear has decreased to only 8%. MISO now projects that by 2030 renewables will be the leading fuel source of MISO capacity at 32%, followed by gas at 28% and coal decreasing to 27%.

Figure 5-4 – MISO Fuel Mix[19]



[19] Sources: 2005 Mix: MISO Evolution of the Grid presentation on 11/07/17 https://ccaps.umn.edu/documents/CPE-Conferences/MIPSYCON-PowerPoints/2017/GenTheEvolutionoftheGridintheMidcontinentIndependentSystemOperator(MISO)Region.pdf
2018 Mix: MISO 2019 MTEP https://cdn.misoenergy.org/MTEP19%20Executive%20Summary%20and%20Report398565.pdf
2020 Mix: MISO Corporate Fact Sheet accessed 03/20 https://www.misoenergy.org/about/media-center/corporate-fact-sheet/
2030 Mix: MISO RASC Presentation 2020 Focus presented on March, 2020 https://cdn.misoenergy.org/20200304%20RASC%20Item%2002%20RAN%20Overview%20(RASC009%20RASC010%20RASC011%20RASC012)432103.pdf



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, that 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: expected generation output during peak-load conditions, generator characteristics and the past three years of operational performance. 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.

MISO has shifted from 96% dispatchable generation (all forms of generation except renewables) in 2005 to approximately 83% currently and is forecasted to be at 60% in

2030. 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.

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 Events have historically been rare in nature, with MISO experiencing 3 events between 2009 to 2015 and they occurred only during peak load condition summer months. However, since 2016 there have been 10 events, spanning all four weather seasons. In January of 2019, MISO, for the first time in its existence, interrupted energy service to Industrial Customers enrolled as Load Modifying Resources (LMR). Going forward customers enrolled as LMRs must consider the increased possibility of future interruptions. It is likely that some LMRs will end their participation due to the heighted risk.

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 "ensure the processes in use appropriately assure the conversion of committed capacity resources into sufficient energy every hour of the Planning Year. A dramatically changing landscape has made this conversion process increasingly more uncertain. Therefore, an issue and solution development effort will help MISO and its stakeholders identify and meet the challenges posed by current and future portfolio and technology changes facing the region."

The RAN initiative has led to market mechanism reform that is currently underway. Such reform has included changes to the ability to interrupt customers enrolled as Load Modifying Resources/Interruptible Load. MISO currently has reform initiatives[20] that are high priority that include Emergency Energy Pricing, which would allow higher cost energy resources to set pricing, thereby increasing energy pricing during emergency events, increasing the Energy Offer Cap from $1,000/MWh to $2,000/MWh, thereby allowing generation to double its maximum offer price and allow prices to reach a higher threshold, instituting a Seasonal Planning Resource Auction construct, which would break up the current annual capacity auction to seasonal auctions that would adjust the PRMR and capacity accreditation for resources during these periods. Vectren considered the potential for winter and summer accreditation.

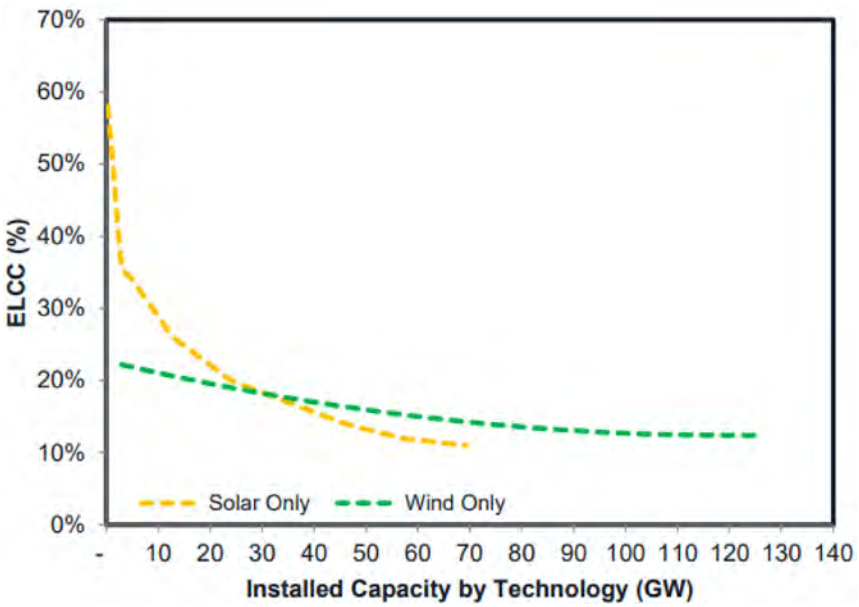
5.7 MISO CAPACITY CREDIT

Each resource option receives varying amounts of capacity credit towards MISO's resource adequacy requirement based on their ability to reliably contribute energy at the peak demand hour. 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 ~96 MWs out of every 100 MWs of installed capacity towards meeting MISO's summer planning reserve margin requirement. This amount increases in the winter for gas resources due to air density in cold weather conditions. 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.

[20] MISO 2019 Market Roadmap: https://cdn.misoenergy.org/MISO%20Market%20Roadmap194258.pdf

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 received a capacity credit of only 7.8% for MISO's 2019-2020 planning year, meaning for every 100 MWs of installed wind capacity, 7.8 MWs would count towards meeting MISO's 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 5-5.

Figure 5-5 Decreasing solar and wind ELCC as more is installed[21]



[21] Renewable Integration Impact Assessment (RIIA) Assumptions Document Version 6, December 2018, MISO, page 11, https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v7429759.pdf

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 revised. Over time, this results in a lower accreditation value as additional resources come online.

While MISO's current methodology for determining resource adequacy only considers the summer peak, they have begun to discuss the inclusion of other seasons. 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 5-6. 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 later in the day. These combined effects result in lower solar winter capacity accreditation. 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 shape are shown in Figure 5-7 gas resource or other dispatchable generation, benefits from being able to turn on and off as needed with exception to unit outages and therefore have higher capacity accreditation than non-dispatchable intermittent resources. For reference, a typical gas resource seasonal capability difference is shown in Figure 5-8.

Figure 5-6 Average Solar PV energy production summer versus winter

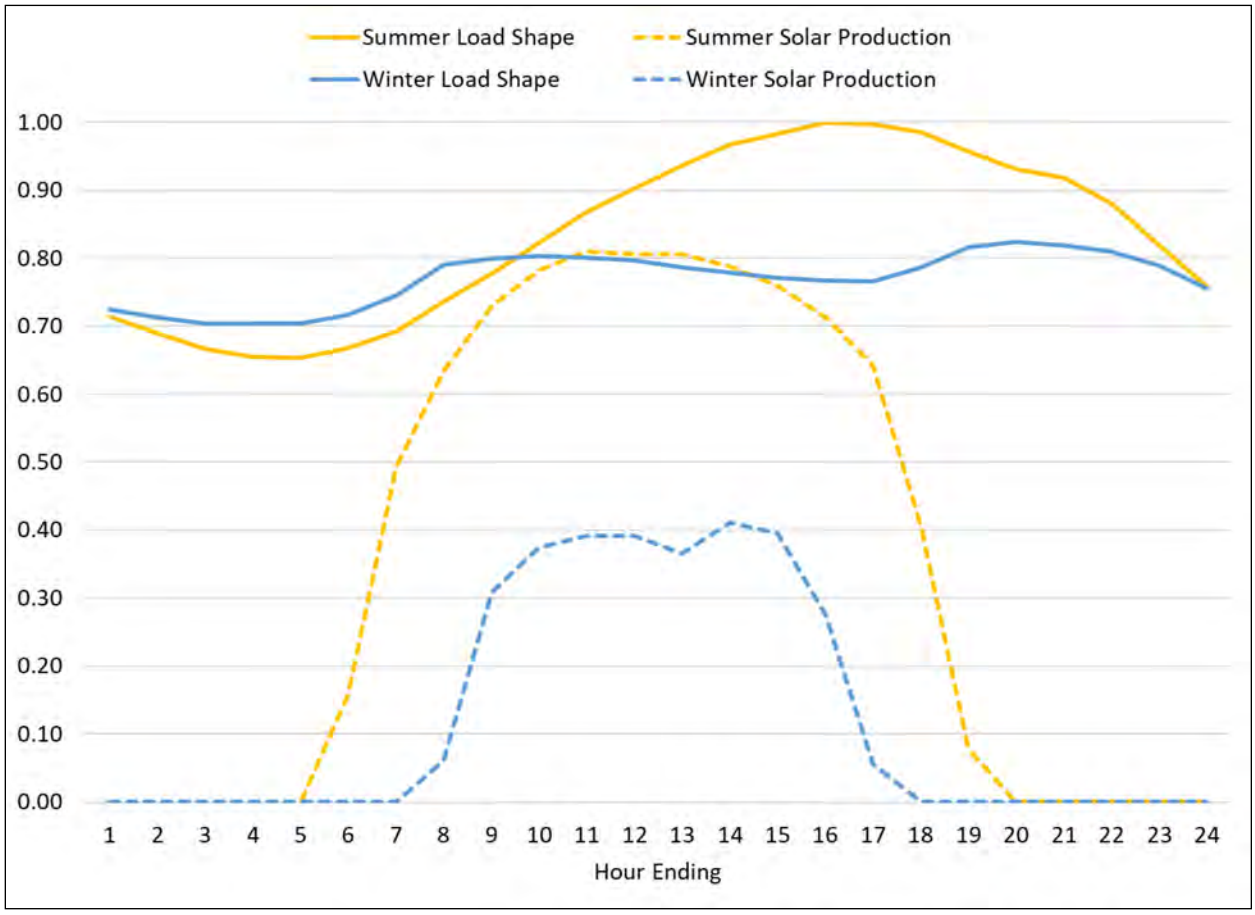


Figure 5-7 Average Wind energy production summer versus winter

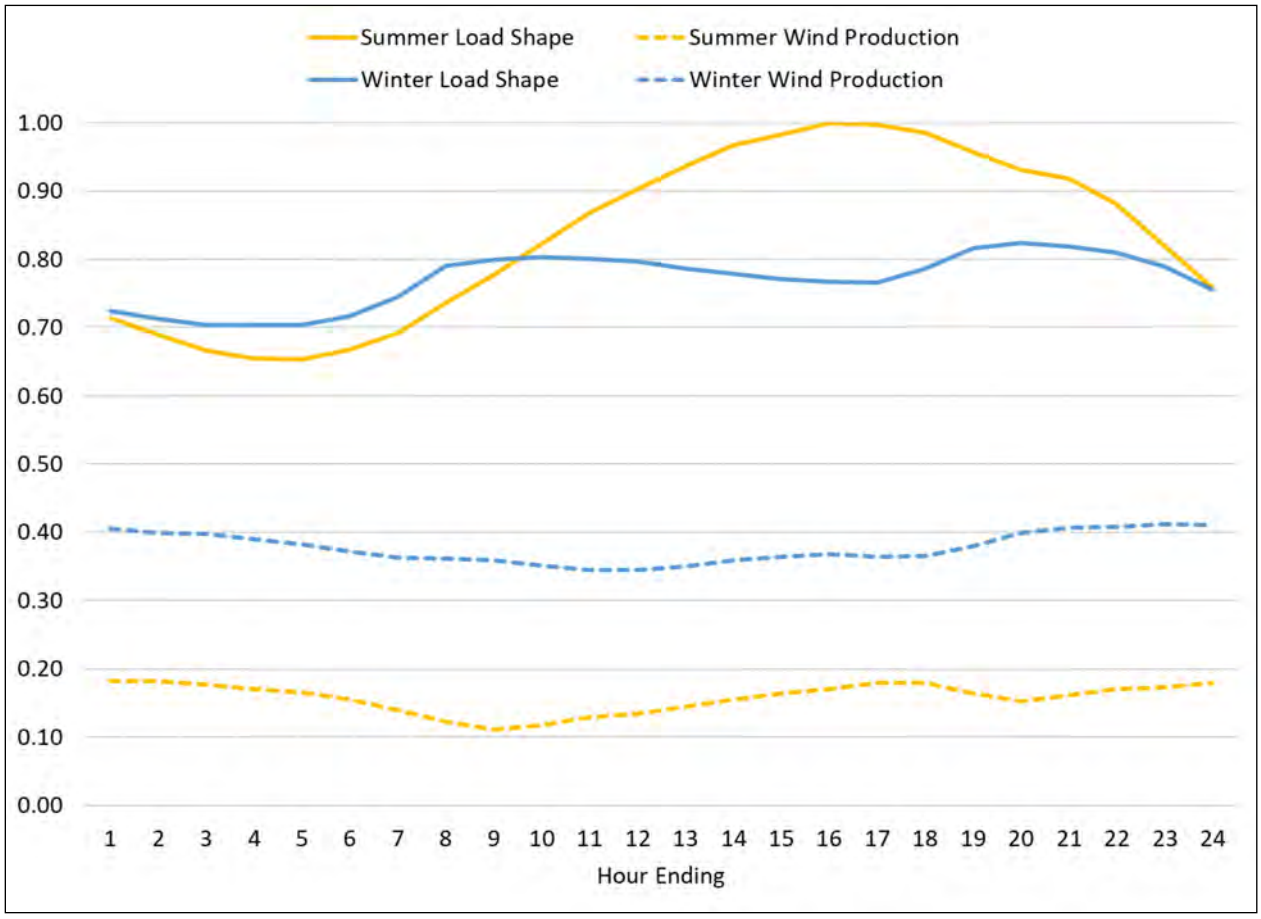
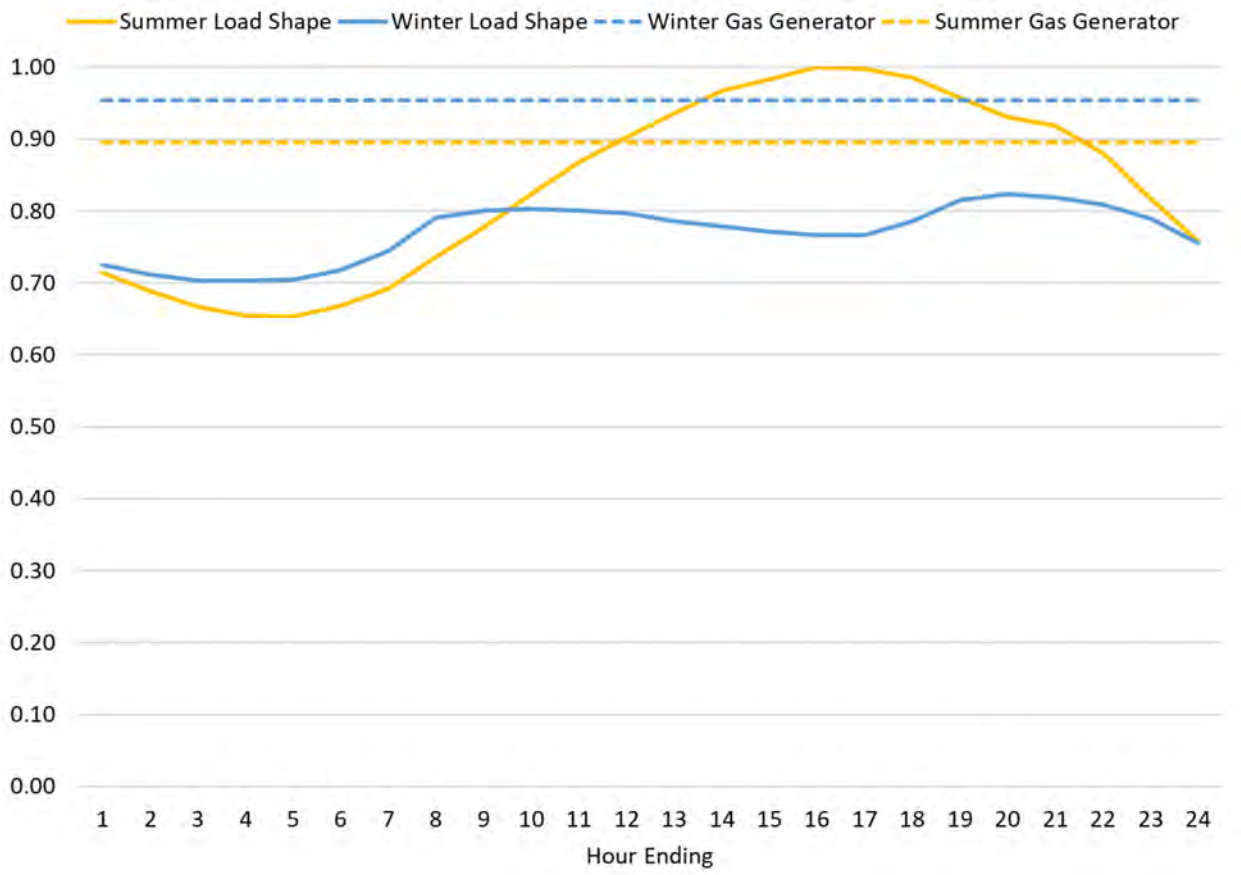


Figure 5-8 Average Gas Resource energy potential summer versus winter



MISO has already implemented seasonal coordinated maintenance schedule reporting. Additionally, MISO currently is considering implementing a seasonal construct to capacity accreditation. Based on recent MISO publications, discussions and input, this likely could be a four-season construct which is planned to be implemented as soon as 2022. Publicly posted feedback from MISO stakeholders and MISO indicated accreditation should vary by season and reflect expected availability of resources in each season. Vectren is a member of MISO and as such cannot ignore nor avoid updates to MISO's accreditation process. Vectren has utilized a conservative summer and winter capacity accreditation construct as part of this IRP as a means of preparing for this implementation.

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 teamed together 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 served 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 that there may be inadequate capacity within the MISO footprint at some future date. 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 5.9 below illustrates Zone 6's increasing proportion of the entire MISO region shortfall projection and thus increased reliance on neighboring state generation resources. Over the years, the OMS and MISO have updated the methodology to project simply which resources are considered high certainty in hopes of increasing the accuracy of the projection. With these improvements in place since 2017, there is still a projected shortfall. This shortfall is concerning, especially from a zonal standpoint that shows certain zones relying heavily on other zones to meet the overall MISO capacity requirement. The latest OMS survey shows IN Zone 6 as one of the zones most at risk of a shortfall, with a deficit projected to surpass the entire MISO region's deficit. It is worth noting that since 2016 Indiana's Zone 6 has imported capacity to meet its PRMR needs. This means based on current MISO member plans and expectations, Zone 6 is expected to continue importing energy to meet a substantial amount of its needs through the year 2025, the last year of the survey period. This potential long-term reliance on the market makes Zone 6 and Vectren's customers susceptible to volatility in the auction clearing price and the resource adequacy policy and decisions of neighboring Zones. The table below demonstrates that

since 2018 the MISO region has cut its projected shortfall in half, while Zone 6's shortfall has almost doubled.

Figure 5.9 – OMS-MISO Resource Adequacy Survey Results

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

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 5.10 below. These large swings in prices have made it difficult to forecast forward year prices. While the 2020-2021 capacity price was relatively low, neighboring Zone 7, which consists of the lower peninsula of Michigan reached the Cost-of-New-Entry (CONE) rate, which is approximately $257, or ~50 times higher than the $5.00 clearing price. Michigan very narrowly missed cone in the 2019-2020 planning year. Since then, MISO updated market rules to ensure only units that enter the auction will be available at the time of need, the likelihood of price increases intensifies.

Figure 5.10 – MISO Capacity Prices

Planning Year	Highest Clearing price for MISO-region	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/day[22]	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	1495% Increase
2015-2016	$150.00	$3.48	$1,270.20	79% Decrease
2016-2017	$72.00	$72.00	$26,280.00	1969% 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

5.9 MISO Energy Prices

Energy prices in MISO have decreased in the last 18 months and are at all-time lows. The main driver of the price decrease is tied to the marginal generation units that set the energy price. Natural gas and renewables have shifted the marginal generation mix from coal to natural gas. Even prior to COVID-19, Natural gas prices were at historic lows, recently in the $2 range due to increased U.S. and global production and warmer than normal winter weather causing an oversupply, which has lowered the operating costs of natural gas generation. This has lowered the bids of generation in the MISO market and led to lower clearing prices as depicted below:

[22] 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).

Figure 5.11 – MISO Clearing Prices

Indiana Hub/Henry Hub Yearly Averages
2015 - YTD Apr. 2020

Year	Indiana Hub Real Time ATC Average	YoY% Change	Indiana Hub Day Ahead ATC Average	YoY% Change	Henry Hub Average	YoY% Change
YTD 2020	$21.02	-20.39%	$21.60	-19.81%	$1.83	-27.05%
2019	$26.41	-19.95%	$26.98	-18.72%	$2.51	-19.41%
2018	$32.99	12.59%	$33.19	12.97%	$3.12	5.36%
2017	$29.30	4.86%	$29.38	4.50%	$2.96	19.10%
2016	$27.94	-0.27%	$28.11	-1.94%	$2.49	-4.60%
2015	$28.02		$28.67		$2.61	

Over time, it is expected that natural gas prices will increase, but remain 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. Each of the All-Source RFP proposals were analyzed to determine its associated impacts to the transmission system as well as the associated Network Upgrade costs.

The MISO Generator Interconnection (GI) process is a three-phase study cycle that has been conducted twice annually (recent schedule is reduced to once per year) to study the impact and any associated transmission system upgrade costs as a result of new generation connecting to the MISO transmission system. Usually there is a study cycle in the 1st quarter and 3rd quarter of each year. 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. These two study cycles are the only two periods in which to enter

the GI queue each year. Mid-year and mid-queue requests are not allowed. After all modeling details are finalized the study enters the Definitive Planning Phase (DPP). The DPP is broken into three phases that are restudies based on immaterial changes to generator attributes and the removal of projects that decide not to proceed to the next study phase. 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.

MISO estimates the process to take 505 days, start to finish. However, with the record amount of interconnection requests that MISO has seen in the last two years, the process is averaging over 2 and a half years per MISO's DPP schedule update posted 3/1/2020. 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.

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 after prior 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 at the Brown site are valuable. MISO allows for an expedited process for new generation with existing interconnection rights; this helps to shield customers from potential upgrade costs should Vectren enter the MISO queue at another site.

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	Completed/Proposed Date
RFP Issued	Wednesday, June 12, 2019
Notice of Intent, RFP NDA and Respondent Pre-Qualification Application Due	5:00 p.m. CDT, Thursday, June 27, 2019
Respondents Notified of Results of Pre-Qualification Application Review	5:00 p.m. CDT, Wednesday, July 10, 2019
Proposal Submittal Due Date	5:00 p.m. CDT, Friday, August 9, 2019
Initial Proposal Review and Evaluation Period	Friday, August 9, 2019 – Wednesday, September 18, 2019
Proposal Evaluation Completion Target and Input to Vectren	2nd Quarter, 2020
Due Diligence and Negotiations Period	Mid 2020
Definitive agreement(s) Executed (subject to regulatory approvals) with Selected Respondent(s)	Late 2020
Petitions (if required) filed with the IURC, the Federal Energy Regulatory Commission (FERC), or any other required agency/commission	TBD

6.1.1 RFP Issued

Burns & McDonnell issued the All-Source RFP on behalf of Vectren on Wednesday, June 12, 2019 (http://vectrenrfp.rfpmanager.biz/default.aspx). Notice was sent to all known IRP stakeholders and posted on www.vectren.com/IRP. The RFP was advertised across multiple media outlets, including Megawatt Daily (~20,000 recipients), North American Energy Markets Association (NAEMA) (150 members) and Midwest Energy Efficiency Alliance (MEEA) Minute (161 members). It was also sent directly via e-mail to participants of Vectren's 2017 RFP, an internal Burns & McDonnell RFP contact list (>450 industry

contacts) and Vectren industry contacts. While the RFP included general requirements and communicated that 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 Vectren 2019 All-Source RFP in Technical Appendix Attachment 6.3.

6.1.2 Notice of Intent

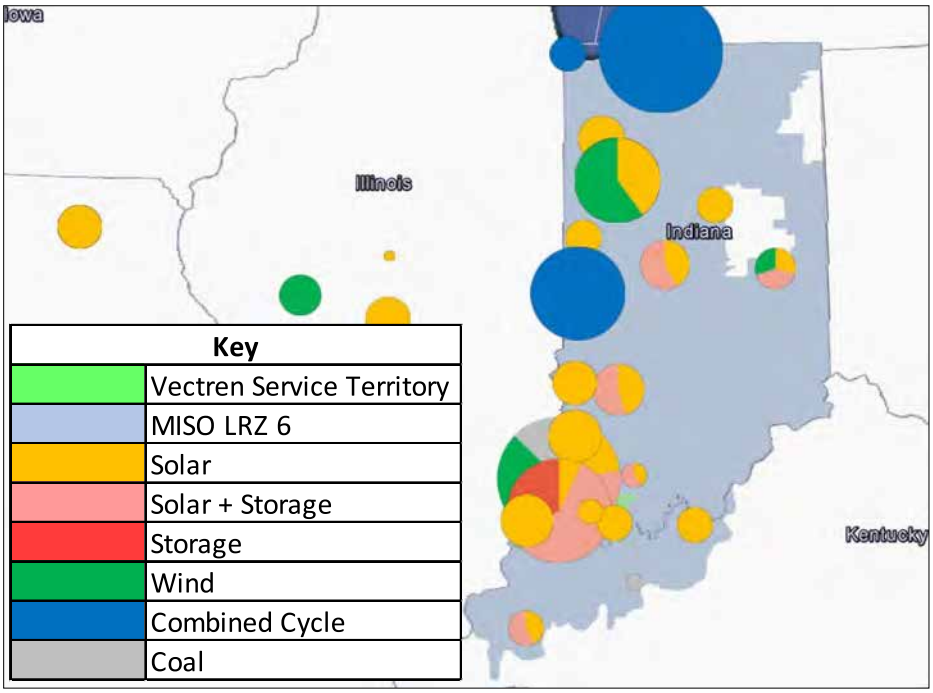
Respondents were given more than two weeks to submit a Notice of Intent to participate in the RFP process, sign the Non-Disclosure Agreement and complete the Pre-Qualification Application. The purpose of the Pre-Qualification Application is to verify that Respondents have adequate experience and financial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

6.1.3 Proposal Review

The Proposal Submittal Due Date was Friday, August 9, 2019. After all Proposals had been received, Burns & McDonnell 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 110 Proposals were received from 22 Respondents. The Proposals comprised eight battery storage, two coal, seven combined cycle gas, one LMR/DR, 57 solar, 19 solar plus storage, three system energy and 13 wind. Of the 110 Proposals, 91 were in Indiana. The Proposals contained approximately 21 GW of total installed capacity; however, many of the projects were included in multiple proposals. There was approximately 10 GW of unique project installed capacity after accounting for double counting. For example, a single 100 MW wind farm 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 Map of Proposals Received



6.1.4 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, Burns & McDonnell performed a steady state analysis using the appropriate DPP Study Group cases and auxiliary files. These selections were evaluated against the impact criteria defined in Section 6.1.1.1.8 of MISO's BPM-015 (Business Practices Manual), including the cumulative impact criteria.

Finally, for those selections that have not entered the queue or did not have a DPP Study Group case available, the most recent DPP Study Group case was used for the

evaluation. The same impact criteria were applied with the exclusion of the cumulative impact criteria.

Figure 6-3 - RFP Project Definitive Planning Phase (DPP) Study Groups

Number of RFP Projects in DPP Study Group	Study Group	Network Upgrade (NU) Cost From:	Burns and McDonnell Action:
1	DPP-2016-FEB Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm Generator Interconnection Requests (GIRs) sharing allocations are active.
1	DPP-2016-AUG Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
4	DPP-2017-FEB Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
10	DPP-2017-AUG Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
5	DPP-2018-APR Central	MISO DPP Report	1. Review Reports for total NU Costs; 2. Confirm GIRs sharing allocations are active.
1	DPP-2018-APR West	Project Group Analysis	1. Perform Project Group analysis to determine potential NU costs for ERIS analysis; 2. Allocate costs to GIRs based on full reconductor/replacement cost estimates.
18	DPP-2019-Cycle1 Central	Project Group Analysis	1. Perform Project Group analysis to determine potential NU costs for ERIS analysis; 2. Allocate costs to GIRs based on full reconductor/replacement cost estimates.

For any impacts reported, without any information on the limitation of the facility, Burns & McDonnell assumed a full rebuild scope and cost of the facility. NU costs for the reported impacts were developed using MISO's MTEP transmission cost estimation guide. These NU costs were considered for the evaluation of each proposal. Many Proposals included allowances for NU costs or indicated all NU were included in their Proposal and these nuances were accounted for during the analysis.

6.1.5 Grouping

Proposals were divided into groups based on characteristics such as technology type, ownership structure and contract duration. 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.

Proposals were divided into two tiers, based on factors that could add cost risk to Vectren customers. Tier 1 Proposals were those that included binding pricing and delivery of energy to SIGE.SIGW (Vectren's load node) or were physically located in Vectren's service territory. Tier 2 included the remaining Proposals that were not classified as Tier 1. Tier 2 Proposals generally did not provide a binding bid price and/or were located off Vectren's system, which increases cost risk due to congestion. Despite these risks, several were still analyzed and considered during the RFP evaluation process; however, Vectren wanted, to the extent possible, to include bids with more price certainty within the IRP modeling in order to protect customers from price volatility.

Seventeen (17) groups were formed. This resulted in data from 49 Tier 1 Proposals being used in IRP analysis. A summary of the Proposal grouping is shown in Figure 6-4. As seen in Figure 6-4, the energy-only Proposals were not put into a group because they did not meet the capacity requirement of the RFP. Due to a high quantity of bids in the group and to provide additional granularity in IRP modeling, groups 15 and 17 were split into high and low-cost groups.

Figure 6-4 Proposal Grouping

Grouping		RFP Count	Tier 1	Tier 2
1	Coal PPA	2	0	2
2	LMR/DR PPA	1	1	0
3	CCGT PPA	2	0	2
4	CCGT Purchase	5	0	5
5	Wind Purchase	2	0	2
6	12-15 Year Wind PPA	9	4	5
7	20 Year Wind PPA	2	1	1
8	Storage Purchase	4	4	0
9	Storage PPA	4	4	0
10	Solar + Storage PPA	6	5	1
11	Solar + Storage Purchase	9	5	4
12	Solar + Storage Purchase/PPA	4	1	3
13	Solar Purchase/PPA	6	1	5
14	12-15 Year Solar PPA	8	3	5
15	20 Year Solar PPA	16	10	6
16	25-30 Year Solar PPA	9	3	6
17	Solar Purchase	18	7	11
N/A	Energy Only	3	0	3
	Total	**110**	**49**	**61**

The costs for Tier 1 Proposals are outlined in Figure 6-5. Costs were not shown for groups that contained only one project to ensure confidentiality.

Figure 6-5 - Tier 1 Cost Summary[23]

Group		# Proposals	# Projects	Proposal ICAP (MW)	Project ICAP (MW)	Capacity Weighted Average LCOE ($2019/MWh)	Capacity Weighted Purchase Price ($/kW)[2]
1	Coal PPA	0					
2	LMR/DR PPA	1	1	50	50		
3	CCGT PPA	0					
4	CCGT Purchase	0					
5	Wind Purchase	0					
6	12-15 Year Wind PPA	4	1	800	200		
7	20 Year Wind PPA	1	1	300	300		
8	Storage Purchase	4	2	305	152	$157	
9	Storage PPA	4	2	305	152	$135	
10	Solar + Storage PPA	5	3	902	526	$44	
11	Solar + Storage Purchase	5	3	862	486	TBD[1]	$1,417[3]
12	Solar + Storage Purchase/PPA	1	1	110	110		
13	Solar Purchase/PPA	1	1	80	80		
14	12-15 Year Solar PPA	3	2	350	225	$32	
15	20 Year Solar PPA	10	8	1,522	1,227	$35	
16	25-30 Year Solar PPA	3	2	400	275	$34	
17	Solar Purchase	7	6	902	732	TBD[1]	$1,262

1. The method for realizing tax incentives is being reviewed by Vectren
2. $/kW costs are in COD$, purchase option cost is the purchase price unsubsidized by applicable tax incentives and does not reflect ongoing operations and maintenance costs
3. Cost based on simultaneous MW injectable to the grid

6.1.6 Evaluation of Proposals

Burns & McDonnell quantitatively and qualitatively evaluated all conforming generation facility Proposals. Proposals were evaluated relative to others within the same grouping

[23] Note that proposals based on one project do not include capacity weighted Average LCOE or Capacity Weighted Purchase Price to maintain confidentiality of the bid.

using the scoring criteria set forth in the RFP. The scoring criteria included four major categories: LCOE, energy settlement location, interconnection/development status and local clearing requirement 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 that Vectren is serious about pursuing projects following the completion of the IRP analysis. Vectren does not believe that RFP's 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 6-6.

Figure 6-6 Scoring Summary

Scoring Criteria Name	Points		Scoring Method	Definition	Importance
LCOE Evaluation	150		Curve	$/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 Vectren's customers.
Energy Settlement Location	100		Binary	Proposals that include all costs to have energy financially settled or directly delivered to Vectren's load node (SIGE.SIGW)	Having financial settlement or direct delivery to Vectren's load node provides Project's true resource cost to Vectren's customers, eliminating risks/costs associated with the delivery of energy.
Interconnection and Development Status	60		Binary	Executed a pro-forma MISO Service Agreement and Interconnection Construction Services Agreement (12 points) Completed a MISO Facilities Study (12 points) Completed a MISO System Impact Study (12 points) Achieved site control and completed zoning requirements (12 points) EPC Contract awarded (12 points)	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 cost certainty improves.
Local Clearing Area Requirement	30		Binary	Physically and electrically located in LRZ 6	Being located in LRZ 6 provides greater certainty that asset capacity can be deliverable to Vectren and fall within LCR requirements through entire life or contract term.
Credit and Financial Plan	20		Curve	Vectren will be reviewing the credit rating and financing capabilities in relation to a Bidder's Project.	Projects which lack the financial wherewithal to ensure development pose a significant risk to Vectren and their customers.
Development Experience	20		Curve	Scored based on 1,500 MW of relevant development experience	Relevant technology experience is important when looking at asset purchases or PPA's for facilities which are not in service. A Bidder's track record of project completion is a benefit to the Project's scoring.
Sole Ownership/Partial Owner	20		Binary	Being a sole owner would allow full site and dispatch rights/preferences	Being able to solely own, operate, and maintain a Project lowers risks for Vectren and their customers.
Ownership Structure (Purchase/PPA)	20		Binary	Vectren has a preference for ownership	Owning an asset and having control with regards to dispatch, maintenance, and operation of the facility lowers risks for Vectren and their customers.
Operational Control	20		Binary	Dispatch parameters used for the scheduling of energy into MISO and approval for maintenance outage periods	Operational control provides the ability to make prudent operational decisions when it makes economic sense for Vectren's customers.
Fuel Risk	20		Binary	Sites having firm and reliable fuel supply	Having fuel restrictions or a lack of reliable fuel could effect the operation of the Project and be a risk to the owner/off taker.
Delivery Date	20		Curve	For each year prior or after MISO PY 2023/2024, 25% of the points will be deducted	To the extent resources are brought on-line before potential Vectren unit retirements, Vectren customers could pay for duplicative capacity and/or energy; while there may be reasons to proceed with such projects, in recognition of their incremental costs, it is appropriate for such projects to not score as well in terms of timing.
Site Control	20		Binary	Proper rights to the site in which the facility will be located	Without proper permitting and permissions from the owner, there is a risk that the project may not move forward or could experience significant delays.

RFP bids were rank ordered 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 that the individual, highest-scoring qualified Proposal(s) will be selected. For further discussion of the evaluation criteria and results see Technical Appendix 6.9.

6.1.7 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. Vectren believes that, at a minimum, a year is needed to conduct an IRP analysis. While Vectren asked bidders to keep bids open for a year after bid submittal, this does not mean that developers are able to wait until the process is complete.

As a result, some bids were withdrawn from Vectren's RFP during the IRP because the projects were acquired by other load serving entities. This delay has hurt the ability to act on proposals before they are acquired. During this IRP, at least one project, was purchased by another utility. Competition for projects in MISO zone 6 is steep with many utilities (NIPSCO, IPL, Hoosier Energy, IMPA and Vectren) currently all vying for announced projects that have more certainty of being developed.

Vectren has also had several attractive local wind and solar projects drop out of the MISO Generation Interconnection queue due to commitments/costs required from interconnection studies and they are no longer available at this time. Often projects are speculative. Developers apply with MISO to develop a project and are put in the MISO queue, as a series of studies is conducted. Each study requires more money from the developer in the form of milestone payments. Early studies put less money at risk for the developer. As interconnection costs for a project are identified the developer must make

a choice to stay in the queue or drop out. Without certainty of an off taker, many projects drop. Long lead times increase this risk.

Additionally, some initial cost estimates have proved to be too low. As a project moves along, several issues can arise, including: updated engineering identifying new costs, environmental permitting, local pushback, local permitting, updated interconnection costs, updated risk assessments by the developers, etc.

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. Vectren'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. Vectren'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. Vectren'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, Vectren'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.

Vectren's current generation mix consists of approximately 1,280 megawatts (MW) of installed capacity. This capacity consists of approximately 1,000 MW of coal-fired generation, 160 MW of gas fired peaking generation, 3 MW of renewable landfill gas generation, 4 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 6.7 below references both Installed Capacity (ICAP) and Unforced Capacity (UCAP). Installed capacity is also referred to as nameplate capacity. This is the maximum output that can be expected from a resource. Unforced capacity is the amount of capacity that can be relied upon to meet peak load. MISO uses UCAP for planning purposes. The UCAP accreditation recognizes that all resources are not equally reliable or, in some cases, capable of achieving their design output. MISO uses a three-year reliability history and a weather normalized capability verification to determine the UCAP accreditation of each unit. Vectren used historical data and MISO's current methodology for thermal units to determine seasonal accreditation values along with the MISO UCAP planning reserve margin requirements (8.9% PRM[24]) in the current IRP. This information was utilized to help ensure that all portfolios met MISO obligations on a seasonal basis.

Figure 6.7 – Vectren Generating Units

Unit	Installed Capacity ICAP (MW)	Summer Unforced Capacity UCAP (MW)	Winter Unforced Capacity UCAP (MW)	Primary Fuel	Year Unit First In-Service
A.B. Brown 1	245	197	235	Coal	1979
A.B. Brown 2	245	232	221	Coal	1986
F.B. Culley 2	90	85	84	Coal	1966
F.B. Culley 3	270	261	263	Coal	1973
Warrick 4	150	133	137	Coal	1970
A.B. Brown 3	80	73	90*	Gas	1991

[24] Planning Year 2020-2021 Load of Load Expectations Report; MISO; https://cdn.misoenergy.org/2020%20LOLE%20Study%20Report397064.pdf; 11/01/2019; page 5

Unit	Installed Capacity ICAP (MW)	Summer Unforced Capacity UCAP (MW)	Winter Unforced Capacity UCAP (MW)	Primary Fuel	Year Unit First In-Service
A.B. Brown 4	80	72	82*	Gas	2002
Blackfoot	3	N/A[25]	N/A[26]	Landfill Gas	2009
Oak Hill Solar	2	N/A[22]	N/A[25]	Sun	2018
Volkman Road Solar	2	N/A[25]	N/A[25]	Sun	2018

*Installed capacity shown at 59°F, winter UCAP shown at 20°F

6.2.1 Coal

The A.B. Brown Generating Station (ABB), located in Mt. Vernon, IN, consists of two coal fired units, each with an installed capacity of 245 MW. ABB Unit 1 began commercial operation in 1979, while ABB Unit 2 became operational in 1986. Over the last three years these units have operated at an average capacity factor of 53%.

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 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

[25] 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.

ash, is part of Vectren'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.

While the A.B. Brown units began commercial operation after the Culley units, the dual-alkali scrubbers on these units present several operational challenges. First, based on historical costs the variable production cost associated with the scrubbers is approximately six times greater than the limestone-based scrubber installed on the Culley units. Also, the dual-alkali process is corrosive which results in high maintenance costs to keep the FGD's and associated equipment operational. And finally, these FGD's are the last dual-alkali scrubbers in operation in the U.S. and are nearing the end of their useful life. This can lead to challenges obtaining operational support and replacement parts when needed.

A.B. Brown Units 1 and 2 burn Illinois basin bituminous coal, which is mined in Knox County, IN and is delivered via rail.

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, IN, 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 23% while Unit 3 was 65%.

FBC is scrubbed for Sulfur Dioxide (SO_2) emissions, utilizing an FGD process which is shared by both units and was retrofitted in 1994. This standard technology is much more cost effective than A.B. Brown's scrubber. The captured SO_2 is converted into synthetic gypsum within the system and, as part of Vectren'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, IN where it is used in the manufacture of drywall. Sulfur trioxide (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 Selective Catalytic Reduction (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 Vectren'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.

The F.B. Culley units burn Illinois basin bituminous coal, which is mined in Knox County, IN and delivered via truck. F.B. Culley 3 is Vectren's most efficient coal unit with an industry standard scrubber, which has much lower variable costs than ABB1 and ABB2. As such F.B. Culley 3 is in the process of upgrades to comply with EPAs ELG rule.

Warrick Unit 4 (Warrick) located near Newburgh, IN is a coal fired unit operated and maintained by Alcoa Power Generating Inc. Vectren maintains 50% ownership of Warrick Unit 4. It has an installed capacity of 300 MW which began commercial operation in 1970. Vectren's 50% interest is equal to 150 MW. Over the last three years this unit has operated at a capacity factor of 62%.

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 Vectren's beneficial reuse program) is shipped via truck to a facility near Shoals, IN 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 Vectren'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. Vectren purchases coal for its share of Warrick Unit 4, which is mined in Knox County, IN and is delivered by rail.

6.2.2 Natural Gas

The A.B. Brown Generating Station 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 1% with Unit 4 at 2%.

6.2.3 Renewables

The Blackfoot Clean Energy Facility located in Winslow, IN 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 42%.

The Oak Hill and Volkman Road universal solar projects in Evansville, IN 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 Vectren load for this analysis. In 2019 the solar installations operated at an average annual capacity factor of 21%. The average annual capacity factor is affected by hours of daylight, cloud cover, temperature, etc. This installation was available over most hours in 2019.

A third solar facility is under development near Troy, IN and will have an installed capacity near 50 MW. It is expected to be operational in early 2021.

6.2.4 Energy Efficiency

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

Since 1992, Vectren has operated a Direct Load Control (DLC) program called Summer Cycler that reduces residential and small commercial air-conditioning and water heating electricity loads 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. Vectren's Summer Cycler program has served Vectren and its customers well for more than two decades, but emerging technology is now making the program obsolete. Between 2010 and 2018, Vectren's DSM programs reduced demand by approximately 69,000 kW and provided annual incremental gross energy savings of approximately 360,000,000 kWh.

The table below outlines the estimated program penetration on a yearly basis since Vectren 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 6.8 Gross Cumulative Savings

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh) *	Gross Cumulative Savings (GW) *	Percent of Sales Achieved (Cumulative)
2010	5,616.87	2.53	.00051	0.04%
2011	5,594.84	19.40	.00331	0.35%
2012	5,464.75	66.95	.01212	1.23%
2013	5,459.11	128.64	.02271	2.36%

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh) *	Gross Cumulative Savings (GW) *	Percent of Sales Achieved (Cumulative)
2014**	3,498.69	175.98	.03053	5.03%
2015	3,223.81	202.82	.03552	6.29%
2016	3,256.3	236.40	.04336	7.26%
2017	3,280.7	268.86	.05005	8.20%
2018	3,490.7	309.28	.05759	8.86%

*Gross Cumulative Savings are adjusted for Residential Behavioral, which has a one-year program life therefore not cumulative in nature.

**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 2018-2020 Plan Overview

Consistent with the 2016 IRP, the framework for the 2018-2020 EE Plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 77% of eligible load. Below is a listing of residential and commercial & industrial programs offered in 2018-2020. For full program descriptions including the customer class, end use of each program and participant incentives provided by the programs, please refer to the 2018-2020 EE Plan detail found in the Technical Appendix Attachment 6.2 Vectren Electric 2018-2020 DSM Plan.

Residential Programs

- Residential Lighting
- Home Energy Assessments and Weatherization
- Income Qualified Weatherization
- Appliance Recycling
- Energy Efficient Schools
- Residential Prescriptive
- Residential New Construction
- Residential Behavior Savings
- Residential Smart Thermostat Demand Response (Incentives only)
- Bring Your Own Thermostat (BYOT)

- Food Bank – LED Bulb Distribution
- Conservation Voltage Reduction (CVR) Residential

Commercial & Industrial Programs

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

The 2018-2020 plan was included 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 6.2 Vectren Electric 2018-2020 DSM Plan).

Figure 6.9 2018-2020 Energy Efficiency Savings

	2018*		2019**		2020***	
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	19,241	4.0	19,129	4.0	15,821	4.7
Commercial & Industrial	21,602	3.2	16,495	3.4	16,208	1.7
Total	40,843	8.5	35,624	7.4	32,029	6.4

* 2018 Evaluation Results used for 2018
** 2019 Operating Plan used for 2019 savings and Net to Gross (NTG) Factors
*** 2018-2020 Filed Plan used for 2020 Savings and NTG Factors

6.2.5 Demand Response

Vectren's tariff currently includes two active demand response programs: 1) the Direct Load Control and 2) interruptible options for larger customers. Demand response programs allow Vectren to curtail load for reliability purposes. Vectren's tariff also

includes a MISO demand response tariff, in which no customers are currently enrolled given the absence of an active demand response program within the MISO market at this time.

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, Vectren compensates customers in exchange for the right to initiate events to reduce air-conditioning and water-heating electric loads during summer peak hours. Vectren can initiate a load control event for 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.

Vectren 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. Vectren also utilizes an outside vendor, The Cadmus Group, to evaluate the DLC program and provide unbiased demand and energy savings estimates.

In 2020 Cadmus predicted that the DLC Program was capable of generating approximately 8.3 MWs of peak demand savings from residential air-conditioning load control and residential water heating load control. 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. Vectren has had a DLC program since the early 1990's and as of 2019 had approximately 21,000 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, Vectren plans to begin replacing DLC switches with smart thermostats.

6.2.5.2 Current Interruptible Load

Vectren makes available a credit for qualified commercial and industrial customers to curtail demand under certain conditions. Vectren included three customers who were participating for a total demand reduction of 35 MW. New MISO testing requirements are currently being put into place to ensure these 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 for the first time that will require load interruptions to meet the test requirements. Prior to January 31, 2019, Vectren had never been requested by MISO to deploy LMRs, thereby interrupting customer load. Because of these changes that will now require annual interruptions that are likely to increase in occurrence and duration, Vectren expects some, if not all, of its currently enrolled customers to drop out, as frequent interruptions in service can be very costly to industrial customers' operations. Since implemented, one customer (~7MWs) has left the program. While aggressive, Vectren maintained industrial interruptible load at the 35 MWs within the model throughout the analysis period. Given Vectren's mix of industrial customers, it is unlikely that new customers will sign up for this program. As such, Vectren did not allow the model to select additional interruptible DR.

6.2.5.3 Smart Thermostats

Vectren 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. Preliminary evaluation results are showing significantly more load reduction delivered by smart thermostats. The current DLC switch program is a well-established means for Vectren to shed load during

peak demand; however, over time, this option is will become obsolete. As such, Vectren has designed a program to change out from switches to smart Wi-Fi thermostats, a strategic option for cost effective load control. The Smart DLC Change-out program will focus on residential single-family homes and apartment dwellers. By installing connected devices in customer homes rather than using one-way signal switches, Vectren 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, Vectren also launched the Bring your Own Thermostat (BYOT) program as a demand response program. The BYOT program is a further expansion of the Residential Smart/Wi-Fi thermostat initiative. The 2018-2020 Plan provides for 240kW demand each year from the BYOT program based on 400 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 0.6 kW - 1 kW per thermostat in load reductions during a DR event.

6.3 POTENTIAL FUTURE OPTIONS MODELING ASSUMPTIONS

Vectren utilized the All-Source RFP for modeling inputs through 2024 for wind, solar, solar + storage resources, (Tier 1 bids) as shown in Figure 6.5. The following supply side information was based on a technology assessment from Burns and McDonnell unless otherwise noted and was used to help provide needed information to model other

resources where Vectren did not receive a Tier 1 bid and for resources in future years and utilizing the cost curve information in Figure 6.21.

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 6-10 for further details on the coal technologies evaluated.

Figure 6-10 – Coal Technologies

Coal		
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 (2019$/kW)	$6,370	$5,760
Fixed O&M Costs (2019$/kW-year)	$29.10	$29.10

6.3.1.2 Natural Gas Technologies

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.

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 MISO has 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. The A.B. Brown site was used for this analysis. It is an existing brownfield site with interconnection rights through MISO. The cost estimates were developed in partnership with a potential service provider, Texas Gas.

Figure 6-11 – Simple Cycle Gas Turbine Technologies

Simple Cycle Gas Turbines					
Operating Characteristics and Estimated Costs	**1xLM 6000 SCGT**	**1xLMS 100 SCGT**	**1xE-Class SCGT**	**1xF-Class SCGT**	**1xG/H-Class SCGT**
Base Load Net Output (MW)	41.6	97.2	84.7	236.6	279.3
Base Load Net Heat Rate (HHV Btu/kWh)	9,280	8,895	11,527	9,928	9,311
Base Project Costs (2019$/kW)	$2,230	$1,660	$1,470	$730	$810
Fixed O&M Costs (2019$/kW-year)[27]	$36.28	$16.04	$21.46	$8.32	$8.02

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 Heat Recovery Steam Generator (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 and G/H class, as shown in Figure 6-12, were evaluated with General Electric (GE) turbines as representative CCGT technologies. The F class 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. Vectren did not model a large 2x1 CCGT. See Figure 6-12 for further details on the CCGT technologies evaluated.

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

Figure 6-12 – Combined Cycle Gas Turbine Technologies

Combined Cycle Gas Turbines		
Operating Characteristics and Estimated Costs[28]	**1x1 7F.05 CCGT (ABB)**	**1x1 7HA.01 CCGT (ABB)**
Duct-Firing	Fired	Fired
Base Load (24/7 Power) Net Output (MW)	365	420
Incremental Duct-Fired (Peaking) Net Output (MW)	72	79
Base Load Net Heat Rate (HHV Btu/kWh)	6,460	6,247
Incremental Duct-Fired Heat Rate (HHV Btu/kWh)	8,269	8,221
Base Project Costs (2019$/Fired kW)	$1,153	$1,087
Fixed O&M Costs (2019$/Base Load kW-year)[29]	$13.99	$15.94

6.3.1.3 Renewables Technologies

Four renewable technologies were evaluated in the IRP. Those technologies were wind energy, solar photovoltaic, hydroelectric and waste-to-energy.

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 6-13 for further details on the variety of wind technologies evaluated. Beyond the RFP bids, the following assumptions were based on the Burns and McDonnell tech assessment.

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

Figure 6-13 – Wind Renewables

Operating Characteristics and Estimated Costs[30]	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 (2019$/kW) / ($/kWh for Storage)	$1,450	$1,450	$1,800 / $650
Fixed O&M Costs (2019$/kW-year)	$40.00	$40.00	$44.14
Variable O&M Costs (2019$/MWh)	Included in FOM	Included in FOM	$14.50 (Storage MWh Only)
Variable O&M Costs (2019$/MWh)	Included in FOM	Included in FOM	$14.50 (Storage MWh Only)
Annual Capacity Factor	28%	38%	

The Production Tax Credit (PTC) is a tax credit per-kilowatt-hour (kWh) for electricity generated by qualified energy resources. The duration of the credit is 10 years after the in-service date for all facilities placed in service after August 8, 2005. The tax credit is $0.015 per kWh in 1993 adjusted by inflation adjustment factor provided by the IRS and rounded to the nearest 0.1 cents. Vectren assumed 2.2% past 2019 IRS values, which was the general inflation used throughout the IRP. The tax credit is phased down by 20 percent per year for wind facilities commencing construction after December 31, 2016. The tax credit reduces from 100 percent for wind facilities commencing construction in 2016 and before, down to 60 percent for wind facilities commencing construction in 2019. See Figure 6-14 below for the percent of production tax credit. For purposes of the IRP, Vectren applied the PTC as if the commence construction was one year prior to the commercial operation date. Modeling assumed a safe harbor assumption of two years PTC extension for generic wind builds.

[30] Based on average of Burns and McDonnell, Pace, and NREL technology assessment information where available.

Figure 6-14 –Production Tax Credit by Year

Commence Construction (Prior to)	Production Tax Credit (%)
2017	100%
2018	80%
2019	60%
2020	40%
2021	60%*
2022	0%
2023	0%

*PTC Extended

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 photovoltaic (PV) technology, which directly converts sunlight to electricity due to the electrical properties of the materials comprising the cell.

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

Figure 6-15 – Solar Photovoltaic

Operating Characteristics and Estimated Costs[31]	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 (2019$/kW)	$1,961	$1,526	$1,414	$1,860
Fixed O&M Costs (2019$/kW-year)	$23.41	$22.91	$18.82	$22.33
Variable O&M Costs (2019$/MWh)	Included in FOM	Included in FOM	Included in FOM	$5.74 (Storage MWh Only)

The Investment Tax Credit (ITC) is a federal tax credit as a percent of basis invested in eligible solar generation. ITC percentage depends on the commencement of construction as shown below in Figure 6-16. For modeling purposes, Vectren assumed commercial operation date and commence construction to be the same year for solar projects. The eligible investment was assumed to be the total invested project costs to build. The ITC was normalized over the book life of the asset, which evenly distributes the tax credit out over the asset book life.

Figure 6-16 – Investment Tax Credit by Year

Commence Construction (Prior to)	Investment Tax Credit (%)
2017	30%
2018	30%
2019	30%
2020	30%
2021	26%
2022	22%
1/1/2022 & beyond	10%

[31] Based on average of Burns and McDonnell, Pace, and NREL technology assessment information where available.

For the purposes of the IRP, all modeled bids received safe harbor for full realization of the ITC. Modeling assumed a safe harbor assumption of two years ITC extension for generic solar builds.

6.3.1.3.2.1 Safe Harboring Methods

There are two options, often referred to as safe harboring methods, that developers can utilize to extend qualifications for the ITC and PTC. First, a project can prove that they have started and maintained construction of the project. Second, a project can purchase five percent of the total project cost. Once these safe harboring methods are initiated the developer has 4 years to complete the project. This allows developers to prolong the usefulness of the ITC and PTC.

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 6-17 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 that 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 that the estimated construction cost of the Cannelton facility was very close to the assumptions used in the analysis.

Figure 6-17 – Hydroelectric

Operating Characteristics and Estimated Costs	50 MW Low-head Hydroelectric
Base Load Net Output (MW)	50
Base Project Costs (2019$/kW)	$6,050
Fixed O&M Costs (2019$/kW-year)	$92.40

6.3.1.3.4 Waste-to-Energy

Two waste-to-energy (WTE) technologies were included within the analysis. Waste fuel is combusted directly in the same way fossil fuels are consumed in other combustion technologies. The heat resulting from the burning of waste fuel converts water to steam, which then drives a steam turbine generator to produce electricity. It should be noted that these types of projects are very site specific and hard to have generic assumptions for use in an IRP. The two fuel types evaluated in the IRP were wood and landfill gas, which are represented in Figure 6-18.

Figure 6-18 – Waste to Energy Technologies

Operating Characteristics and Estimated Costs	Bubbling Fluidized Bed	Landfill Gas IC Engine
Base Load Net Output (MW)	50	5
Base Load Net Heat Rate (HHV Btu/kWh)	13,000	10,740
Base Project Costs (2019$/kW)	$5,640	$4,110
Fixed O&M Costs (2019$/kW-year)	$124.00	$111.78

6.3.1.3.5 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 Pricing (LMP's) where the energy is injected (source) and where the energy is withdrawn (sink). For Vectren to purchase energy outside of Zone 6 (Indiana) or even off Vectren's system in Indiana, Vectren 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.

Vectren's modeling accounted for congestion. As previously described, Vectren modeled tier 1 bid information, which included a "delivered price" (all in price from the developer), or projects on Vectren's system, which minimizes congestion risk. Outside of bid information, projects were generally assumed to be on Vectren's system. Any resource that is outside of Vectren's system must include an evaluation of potential congestion charges.

6.3.1.4 Energy Storage

Two types of energy storage technologies were evaluated in the IRP –lithium-ion batteries (typically short-duration) and flow batteries (long-duration). These are shown in Figure 6-19.

Batteries utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity and ease of installation and operation.

Lithium ion (Li-ion) batteries contain graphite and metal-oxide electrodes and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Li-ion technology has seen a resurgence of development in recent years due to its high energy density, low self-discharge and cycling tolerance.

Flow batteries utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane, in which the charge-inducing chemical reaction occurs and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.

Both Li-ion and flow batteries offer a way of storing low-priced, off-peak generation that can be discharged during higher-priced, peak demand hours (wholesale energy market arbitrage). These storage technologies can also function as transmission assets that can assist in maintaining the reliability of the grid, potentially displacing or deferring the need for more traditional transmission upgrades.

Figure 6-19 – Energy Storage Technologies

Operating Characteristics and Estimated Costs[32]	Lithium Ion 10 MW / 40 MWh	Lithium Ion 50 MW / 200 MWh	Flow Battery 10 MW / 60 MWh	Flow Battery 10 MW / 80 MWh	Flow Battery 50 MW / 300 MWh	Flow Battery 50 MW / 400 MWh
Base Load Net Output (MW)	10	50	10	10	50	50
Round-Trip Cycle Efficiency	85%	85%	68%	68%	68%	68%
Base Project Costs (2019$/kW)	$1,972	$1,562	$3,823	$4,305	$3,034	$3,478
Fixed O&M Costs (2019$/kW-year)	$22.36	$18.85	$110.10	$110.10	$35.06	$35.06
Variable O&M Costs (2019$/MWh)	$6.07	$6.07	$1.50	$1.50	$1.50	$1.50

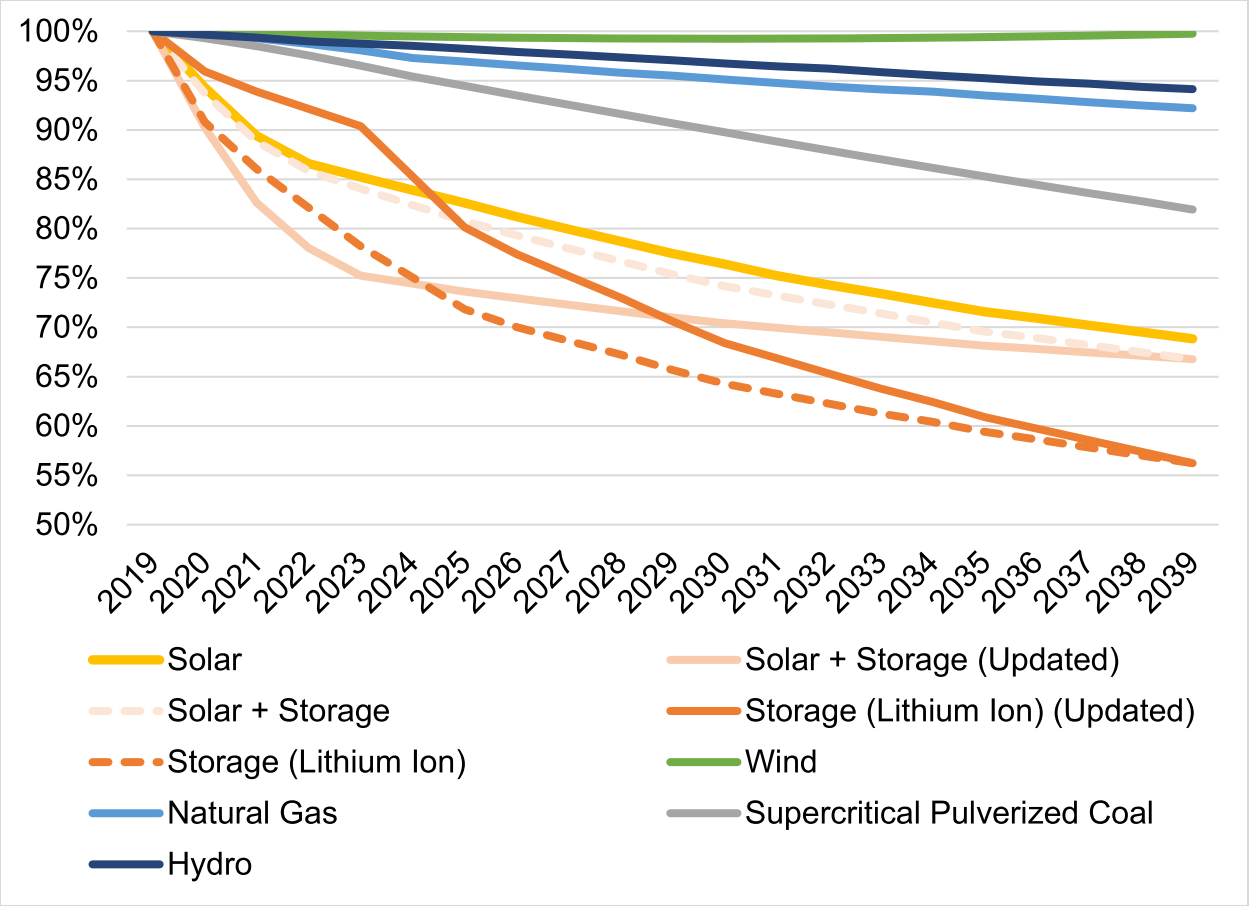
[32] Based on average of Burns and McDonnell, Pace, and NREL technology assessment information where available.

6.3.1.5 Cost Curve Discussion

Forward looking capital cost forecasts were developed and used as part of the 2019/2020 IRP process. Capital cost curves vary based on the generation technology, as shown in Figure 6-21.

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 by ~30% and ~40%, respectively. Due to uncertainty associated with these less mature technologies, Vectren relied upon multiple third-party sources to develop consensus capital cost forecasts. The capital cost forecast curves were adjusted for solar + storage and storage based on data received as part of the RFP process. Solar bids received in the RFP aligned very closely with the original consensus cost curve forecast (these curves are on top of each other in Figure 6-21, solar + storage bids resulted in lowering the near-term forecast, while the bids received for standalone storage resulted in a slight increase to the near term cost curve forecast. These updates help to align Vectren's forecasts with real market data for these less mature technologies. Figures 7.12-7.14 show modeled values by scenario.

Figure 6-20 - Forward Capital Cost Estimates



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 demand side (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."

In addition, this process aligns with Senate Enrolled Act (SEA) 412 which requires that 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, decisionmakers 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."[33] 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.

[33] "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

Potential studies also provide useful information on the benefits and costs of energy efficiency measures and programs from various viewpoints: society as a whole, all ratepayers, the program administrator, program participants and utility rates.

Vectren's MPS completed in 2019 was both to inform the IRP and support the development of a DSM Action Plan for Vectren. The study included primary market research and a comprehensive review of current program, historical savings and projected energy savings opportunities to develop estimates of technical, economic and achievable potential. The study collected primary market research on up-to-date C&I data for the Vectren service area for the saturation of energy-using equipment, building characteristics and the percent of energy using equipment that is already high efficiency. Primary market research was also conducted to understand 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 that 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 that 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 that 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:

1) **Maximum Achievable Potential** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
2) **Realistic Achievable Potential** estimates achievable potential with Vectren 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 that the estimates of technical, economic and achievable 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 Vectren's energy efficiency programs. In the Vectren service area, approximately 75% of large C&I customers are eligible to opt-out and nearly 40% of eligible customers have chosen to do so. As a result, only 22% of total large C&I energy (MWh) sales have not presently opted out of funding Vectren's energy efficiency programs.[34]

6.3.2.3 Energy Efficiency – IRP Reference Case

For the DSM reference case of the IRP analysis, Vectren used the realistic achievable potential identified in the 2019 Market Potential Study as the starting point for developing bundles of energy efficiency to be modeled in .25% increments of eligible sales. However, two additional adjustments to the MPS' realistic achievable energy efficiency potential were necessary prior to inclusion in the IRP.

[34] These percentages are calculated based on 2019 Vectren large C&I customer data and 2018-2019 billing history.

The first adjustment converted the energy efficiency potential from gross savings to net savings. It is appropriate to model net energy efficiency impacts in order to remove MWh and MW impacts that would have occurred even in the absence of Vectren's programs. Net savings were calculated by applying Vectren's most recent (2017) program evaluation results and NTG ratios to the MPS estimates of gross realistic achievable savings. Due to annual differences in the mix of energy efficiency measures included in the realistic achievable potential, the weighted average NTG ratio adjustment ranged from 0.84 to 0.88 across the 20-year IRP analysis timeframe.

The second adjustment aligned the level of low-income potential identified in the realistic achievable potential with levels achieved historically by Vectren. The MPS assumes Vectren pays the full cost for all possible low-income potential savings, regardless of cost-effectiveness. However, this produces a low-income budget that significantly outpaces historical spending for the low-income sector and would create cross-subsidization concerns across customer segments. As a result of aligning the low-income sector spending in the IRP with recent historical levels, low-income achievable savings were also scaled accordingly.

The model included 2020 savings as a fixed resource as savings are currently approved by the Commission in Cause 44927. A total of 10 bundles were modeled for DSM, including one fixed low-income bundle, one fixed DR bundle (AC DLC as well as Smart Thermostat), one selectable DR BYOT (Bring Your Own Thermostat) and seven selectable energy efficiency bundles each representing 0.25% of annual load excluding opt-out sales.

Figure 6-22 shows the realistic achievable potential (as a % of annual forecast sales) identified in the MPS and the impacts after applying the two adjustments described above.

Figure 6-21 – MPS Realistic Achievable Potential (as a % of annual eligible sales) – Pre- & Post-Adjustments

	2020	2021	2022	2023	2024	2025
MPS Realistic Achievable	1.7%	2.1%	2.0%	2.0%	2.0%	2.0%
Adj#1: Gross to Net	1.4%	1.8%	1.7%	1.8%	1.8%	1.7%
Adj#2: Low Income Alignment	1.2%	1.5%	1.4%	1.5%	1.5%	1.5%

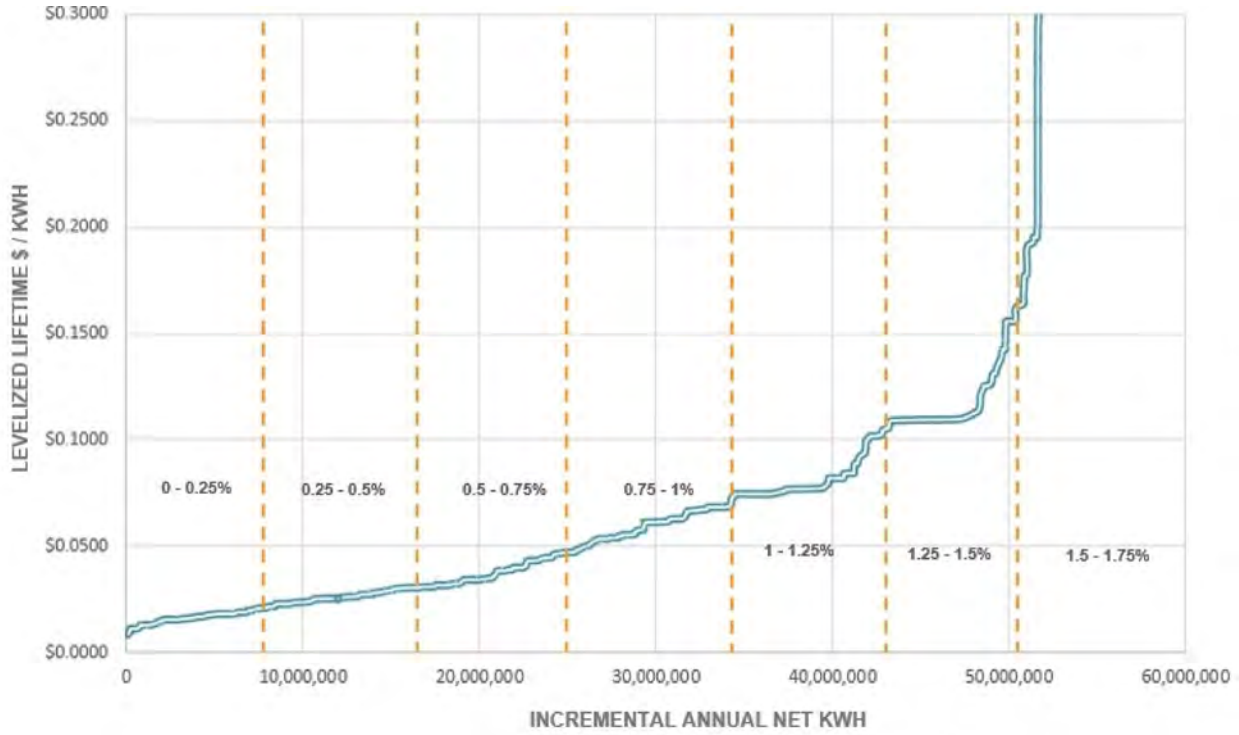
For the Vectren IRP process, energy efficiency is a selectable resource. Once the total energy efficiency savings to be included in the IRP Reference Case were calculated, a cost was assigned to each bundle of energy efficiency so that it can compete and be selected against supply-side resources. Again, the 2019 MPS and the annual supply curves were used to develop costs for each energy efficiency bundle. The costs from the MPS include incentive costs, program delivery costs and other cross-cutting program costs based on reported historical levels. Two modifications to the MPS cost estimates were created to further align the IRP Reference Case with empirical Vectren data. The first adjustment was to reduce incentive costs in the C&I sector from 2020 through 2027. This adjustment served to align modeled costs with Vectren recent historical and 2019 planned costs in the C&I sector. The second adjustment was to change the escalation rate for non-incentive program costs to 2.2% (in lieu of the 1.6% modeled in the MPS) to be consistent with other IRP planning assumptions.[35]

Following these savings and costs adjustments, a supply curve of the remaining electric energy efficiency potential was developed for each year of the MPS. A supply curve of energy efficiency potential is a device for demonstrating the total amount of energy efficiency savings available at specific price points, with the x-axis representing the cumulative annual energy savings available and the y-axis representing the cost of saved energy. The energy efficiency supply curve is useful in that it creates a logical order for pursuing energy efficiency measures based on least cost planning. Energy efficiency measures along the supply curve were then bundled into blocks of approximately 0.25%

[35] Incentive costs were not escalated in the MPS or IRP DSM inputs. Incentives (as a % of measure costs) were held constant in nominal dollars. Any fluctuation in incentives is a result of changes in annual participation.

net energy savings relative to forecast sales. The total number of energy efficiency bundles, each year, is dependent on the realistic achievable potential identified in that year. For example, the realistic achievable potential identified in 2024 allows for 6 complete bundles of 0.25% net efficiency savings and a partial 7th bundle (Figure 6-23).

Figure 6-22 – 2024 Supply Curve for Electric Energy Efficiency



As a final step in the IRP Reference Case energy efficiency bundle development, a single low-income bundle of energy efficiency was created. As noted earlier, this savings bundle is aligned so that total low-income spending in 2020-2039 is consistent with recent historical levels ($1.15 million annually). The cost per lifetime kWh-saved is expected to change over time as the associated mix of low-income measures in the realistic achievable potential changes. Annual savings associated with the LI Bundle range from 889 MWh in the early years of the IRP to a low of 457 MWh as the measure mix converts to higher $/kWh measures over time.

The following table (Figure 6-24) provides the estimated levelized costs, on a cumulative basis, used for each of the energy efficiency bundles included in the IRP Reference Case.

Except for the low-income bundle, no minimum level of energy efficiency impacts was locked in for the IRP optimization modeling for scenario analysis. Empty cells reflect a lack of net achievable potential (based on the MPS results) in that year.

Figure 6-23 – IRP Reference Case Cost of Energy Efficiency; Cost per Net Lifetime kWh[36]

CUM. BIN NET $/kWh	1	2	3	4	5	6	7	LI
2020	$ 0.0163	$ 0.0204	$ 0.0240	$ 0.0299	$ 0.0369			$ 0.1241
2021	$ 0.0154	$ 0.0201	$ 0.0232	$ 0.0268	$ 0.0314	$ 0.0380		$ 0.1448
2022	$ 0.0154	$ 0.0202	$ 0.0245	$ 0.0289	$ 0.0326	$ 0.0394		$ 0.1594
2023	$ 0.0158	$ 0.0206	$ 0.0246	$ 0.0292	$ 0.0342	$ 0.0397		$ 0.1754
2024	$ 0.0162	$ 0.0204	$ 0.0247	$ 0.0302	$ 0.0355	$ 0.0377	$ 0.0412	$ 0.1997
2025	$ 0.0168	$ 0.0217	$ 0.0263	$ 0.0321	$ 0.0375	$ 0.0410	$ 0.0427	$ 0.2134
2026	$ 0.0172	$ 0.0226	$ 0.0278	$ 0.0336	$ 0.0391	$ 0.0426	$ 0.0446	$ 0.2255
2027	$ 0.0179	$ 0.0237	$ 0.0291	$ 0.0357	$ 0.0409	$ 0.0442	$ 0.0462	$ 0.2429
2028	$ 0.0185	$ 0.0250	$ 0.0311	$ 0.0372	$ 0.0426	$ 0.0468	$ 0.0485	$ 0.2469
2029	$ 0.0194	$ 0.0262	$ 0.0330	$ 0.0399	$ 0.0443	$ 0.0499		$ 0.2481
2030	$ 0.0202	$ 0.0283	$ 0.0342	$ 0.0402	$ 0.0457	$ 0.0521		$ 0.2453
2031	$ 0.0210	$ 0.0294	$ 0.0350	$ 0.0423	$ 0.0470	$ 0.0531		$ 0.2517
2032	$ 0.0220	$ 0.0304	$ 0.0388	$ 0.0443	$ 0.0491	$ 0.0557		$ 0.2299
2033	$ 0.0233	$ 0.0317	$ 0.0409	$ 0.0478	$ 0.0505	$ 0.0574		$ 0.2345
2034	$ 0.0241	$ 0.0328	$ 0.0432	$ 0.0497	$ 0.0525	$ 0.0596		$ 0.2038
2035	$ 0.0203	$ 0.0262	$ 0.0323	$ 0.0405	$ 0.0462	$ 0.0480	$ 0.0545	$ 0.2285
2036	$ 0.0206	$ 0.0262	$ 0.0320	$ 0.0405	$ 0.0456	$ 0.0482	$ 0.0547	$ 0.2413
2037	$ 0.0208	$ 0.0264	$ 0.0322	$ 0.0399	$ 0.0457	$ 0.0485	$ 0.0547	$ 0.1969
2038	$ 0.0218	$ 0.0256	$ 0.0324	$ 0.0395	$ 0.0450	$ 0.0499	$ 0.0558	$ 0.2006
2039	$ 0.0231	$ 0.0262	$ 0.0333	$ 0.0398	$ 0.0458	$ 0.0506	$ 0.0564	$ 0.2068

6.3.2.4 Demand Response

Two bundles for demand response savings were included 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 demand response savings associated with Vectren's current demand response capabilities including the historical number of

[36] Savings bundles were based on net savings that were roughly equivalent to 0.25% of annual sales. Projected costs per kWh for each bundle are shown at the gross-level for easier comparison to prior IRP. Projected costs by bundle are cumulative (i.e. the projected cost in Bundle 4 represent the cost to achieve up to 1.0% of forecast sales).

direct load control switches on residential air conditioning units in the Vectren service area. Over the IRP time frame, Vectren anticipates replacing existing direct load control switches with smart thermostats that integrate demand response capabilities (via the Smart Cycle Program). The estimated annual impacts for the fixed bundle of DR is approximately 16 MW in 2020, increasing to 26 MW by 2039.

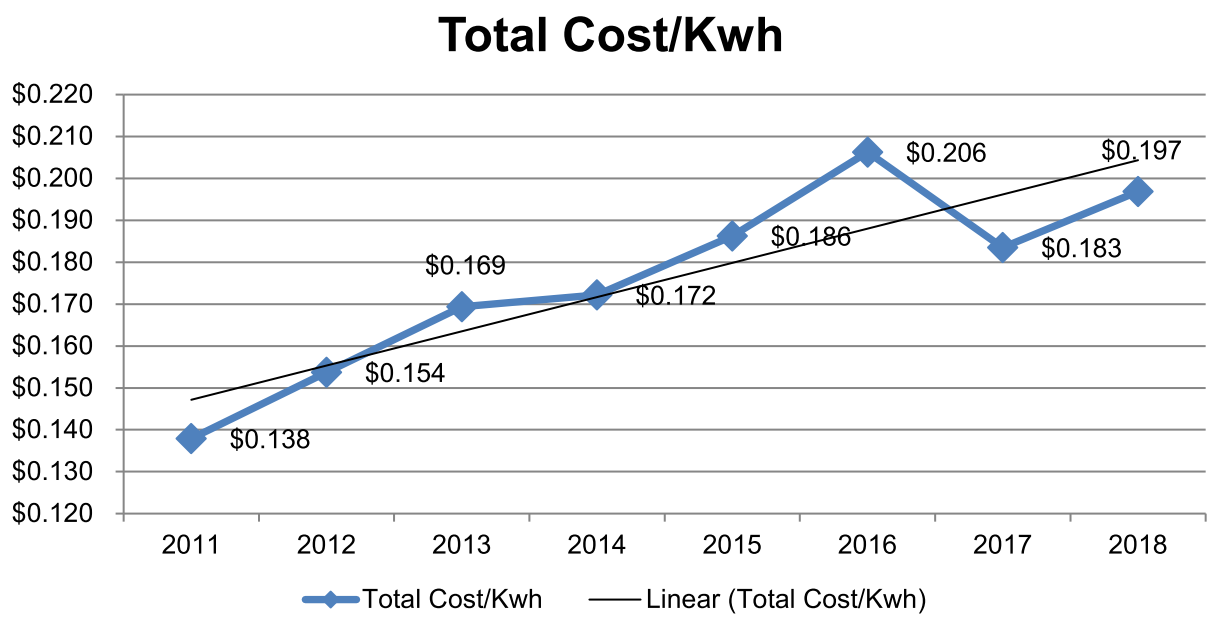
A second bundle, consisting of additional demand response enabled smart thermostats (BYOT Thermostats) above and beyond the current penetration of demand response devices, was included as a selectable resource. This bundle represents an additional 1.6 MW of peak reduction capabilities in 2020 increasing to 10 MW by 2039.

6.3.2.5 DSM Resources – IRP Sensitivities

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, high and low DSM resource cost trajectories were developed by leveraging Vectren's 2011-2018 historical DSM spend per first-year kWh saved and calculating one standard deviation from the mean to develop high and low DSM spend scenarios. This approach uses the actual variation in Vectren's energy efficiency resource acquisition costs to define upper and lower bounds on future DSM costs per first-year kWh-saved. The result is an 11.9% increase or reduction in estimated annual DSM costs relative to the IRP Reference Case. Figure 6-25 shows the 2011-2018 average cost per first-year kWh-saved used to determine the IRP sensitivities on DSM costs.

Figure 6-24 – 2011-2018 Vectren Portfolio Cost per 1st-Year kWh Saved



Applying a range of expected costs produces the following high and low tables of projected DSM resource costs.

Figure 6-25 – High Case Cost per kWh: Plus One Standard Deviation

CUM. BIN NET $/kWh	1	2	3	4	5	6	7
2020	$ 0.0182	$ 0.0229	$ 0.0269	$ 0.0335	$ 0.0413		
2021	$ 0.0173	$ 0.0225	$ 0.0259	$ 0.0300	$ 0.0351	$ 0.0426	
2022	$ 0.0172	$ 0.0226	$ 0.0274	$ 0.0323	$ 0.0365	$ 0.0440	
2023	$ 0.0177	$ 0.0230	$ 0.0275	$ 0.0326	$ 0.0383	$ 0.0444	
2024	$ 0.0181	$ 0.0229	$ 0.0277	$ 0.0338	$ 0.0397	$ 0.0421	$ 0.0461
2025	$ 0.0188	$ 0.0242	$ 0.0294	$ 0.0359	$ 0.0419	$ 0.0458	$ 0.0478
2026	$ 0.0192	$ 0.0253	$ 0.0311	$ 0.0376	$ 0.0437	$ 0.0476	$ 0.0499
2027	$ 0.0200	$ 0.0265	$ 0.0325	$ 0.0399	$ 0.0457	$ 0.0495	$ 0.0517
2028	$ 0.0207	$ 0.0280	$ 0.0348	$ 0.0416	$ 0.0477	$ 0.0524	$ 0.0543
2029	$ 0.0217	$ 0.0293	$ 0.0369	$ 0.0446	$ 0.0496	$ 0.0559	
2030	$ 0.0226	$ 0.0317	$ 0.0382	$ 0.0450	$ 0.0511	$ 0.0582	
2031	$ 0.0235	$ 0.0329	$ 0.0391	$ 0.0473	$ 0.0526	$ 0.0594	
2032	$ 0.0246	$ 0.0341	$ 0.0434	$ 0.0496	$ 0.0550	$ 0.0624	
2033	$ 0.0260	$ 0.0355	$ 0.0458	$ 0.0535	$ 0.0565	$ 0.0642	
2034	$ 0.0269	$ 0.0367	$ 0.0483	$ 0.0556	$ 0.0587	$ 0.0667	
2035	$ 0.0227	$ 0.0293	$ 0.0361	$ 0.0453	$ 0.0517	$ 0.0537	$ 0.0610
2036	$ 0.0231	$ 0.0293	$ 0.0358	$ 0.0453	$ 0.0511	$ 0.0539	$ 0.0612

CUM. BIN NET $/kWh	1	2	3	4	5	6	7
2037	$ 0.0233	$ 0.0295	$ 0.0360	$ 0.0446	$ 0.0511	$ 0.0543	$ 0.0612
2038	$ 0.0244	$ 0.0287	$ 0.0363	$ 0.0442	$ 0.0503	$ 0.0558	$ 0.0624
2039	$ 0.0258	$ 0.0293	$ 0.0373	$ 0.0445	$ 0.0513	$ 0.0567	$ 0.0631

Figure 6-26 – Low Case Cost per kWh: Minus One Standard Deviation

CUM. BIN NET $/kWh	1	2	3	4	5	6	7
2020	$ 0.0143	$ 0.0180	$ 0.0212	$ 0.0264	$ 0.0325		
2021	$ 0.0136	$ 0.0177	$ 0.0204	$ 0.0236	$ 0.0276	$ 0.0335	
2022	$ 0.0135	$ 0.0178	$ 0.0216	$ 0.0254	$ 0.0287	$ 0.0347	
2023	$ 0.0139	$ 0.0181	$ 0.0216	$ 0.0257	$ 0.0302	$ 0.0350	
2024	$ 0.0143	$ 0.0180	$ 0.0218	$ 0.0266	$ 0.0313	$ 0.0332	$ 0.0363
2025	$ 0.0148	$ 0.0191	$ 0.0232	$ 0.0282	$ 0.0330	$ 0.0361	$ 0.0377
2026	$ 0.0151	$ 0.0199	$ 0.0245	$ 0.0296	$ 0.0344	$ 0.0375	$ 0.0393
2027	$ 0.0158	$ 0.0209	$ 0.0256	$ 0.0314	$ 0.0360	$ 0.0389	$ 0.0407
2028	$ 0.0163	$ 0.0220	$ 0.0274	$ 0.0328	$ 0.0375	$ 0.0412	$ 0.0427
2029	$ 0.0171	$ 0.0231	$ 0.0291	$ 0.0351	$ 0.0390	$ 0.0440	
2030	$ 0.0178	$ 0.0250	$ 0.0301	$ 0.0354	$ 0.0403	$ 0.0459	
2031	$ 0.0185	$ 0.0259	$ 0.0308	$ 0.0373	$ 0.0414	$ 0.0468	
2032	$ 0.0194	$ 0.0268	$ 0.0342	$ 0.0391	$ 0.0433	$ 0.0491	
2033	$ 0.0205	$ 0.0279	$ 0.0361	$ 0.0421	$ 0.0445	$ 0.0506	
2034	$ 0.0212	$ 0.0289	$ 0.0380	$ 0.0438	$ 0.0462	$ 0.0525	
2035	$ 0.0179	$ 0.0231	$ 0.0284	$ 0.0357	$ 0.0407	$ 0.0423	$ 0.0480
2036	$ 0.0181	$ 0.0231	$ 0.0282	$ 0.0356	$ 0.0402	$ 0.0425	$ 0.0482
2037	$ 0.0183	$ 0.0232	$ 0.0284	$ 0.0351	$ 0.0402	$ 0.0428	$ 0.0482
2038	$ 0.0192	$ 0.0226	$ 0.0286	$ 0.0348	$ 0.0396	$ 0.0439	$ 0.0492
2039	$ 0.0203	$ 0.0231	$ 0.0293	$ 0.0350	$ 0.0404	$ 0.0446	$ 0.0497

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

6.3.2.5.1 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 2016 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 2021 and 2024 and then evaluates the remaining years

beginning in 2027 as one collective group. This allows the model to select the appropriate level of DSM based on cost-effectiveness differences between the short, mid and long run. Another improvement is the addition of bin specific load shapes which improved accuracy versus utilizing the same average load shape for each bin. Further, DR bundles have been added to the model. The modeled savings were aligned to the latest MPS and conducted price sensitivities mentioned in section "DSM Resources – IRP Sensitivities". The addition of price sensitivities guides Vectren's understanding of energy savings potential as costs might vary.

6.3.2.6 Other Innovative Rate Design

Vectren 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 will be considered now that the required technology upgrades are being finalized, including technology to improve access to multitudes of data provided by installation of AMI. This information was not available for the 2019/2020 IRP.

6.4 TRANSMISSION CONSIDERATIONS

6.4.1 Description of Existing Transmission System

Vectren's transmission system is comprised of 64 miles of 345 kV lines, 377 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 (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, a 345 kV interconnection to Big Rivers' Reid EHV Substation, a 138 kV interconnection at IPL's Petersburg Generation Station and 161 kV and 138 kV interconnections to Hoosier Energy, LGE/KU and Big Rivers at Vectren's Newtonville Substation.

6.4.2 Discussion on Resources Outside of Area

As mentioned above, Vectren'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 750 MWs (or approximately 65% of peak demand). Although Vectren 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, Vectren performed a multitude of transmission planning analysis to study a wide range of potential futures. These included studying the replacement of various levels of coal generation with a Combined Cycle Gas Turbine (CCGT), Combustion Turbines (CTs) and import from the MISO market. Each of these cases also included the addition of various levels of renewable resources, primarily solar and wind. The models utilized were from the latest cycle of the MISO generation interconnection process in order to have the latest modeling data for generation resources in Vectren's area. The renewable resources used for Vectren's analysis were projects already in the MISO queue and existing in the MISO models, while the CCGT and CT's were modeled at Vectren's A.B. Brown power plant for ease of modeling.

The CCGT 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.

As the level of power imported from the MISO market increased due to the coal generation retirements, network upgrades were identified to increase the Vectren system import capability to suitable levels. These projects included the replacement of three transformers at an estimated total cost of $11 million and were needed for all non-CCGT cases, including the CT cases. In addition to these identified import capability issues, voltage issues also arose due to insufficient reactive power reserves as the level of imported power increased. These issues were minimal in the CT cases due to the reactive capability of the CT's and could be resolved with existing facilities, but the issues became substantial in the all renewables by 2030 portfolio and all import cases and would require additional upgrades of $20-$30 million beyond the $11 million described above. 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.

6.5 Partnering with Other Utilities

As a part of the 2019/2020 IRP process, Vectren contacted utilities in the region to discuss opportunities to partner together on generation projects to lower costs. Partnership opportunities with other Indiana utilities did not materialize due to a variety of factors including a lack of alignment in timing, needs, or other factors.

SECTION 7
MODEL INPUTS AND ASSUMPTIONS

7.1 RESOURCE MODEL (AURORA)

AURORAxmp was the primary tool for conducting Vectren's analysis. AURORAxmp is an industry standard chronological unit commitment and dispatch model with extensive presence throughout the electric power industry. The model uses a mixed integer linear programming approach (MILP) to capture details of power plant and transmission network operations while observing real world constraints, such as emission reduction targets, transmission and plant operation limitations, renewable energy availability and mandatory portfolio targets.

The model can be run in several modes; two were utilized for this study. The Long-Term Capacity Expansion mode (LTCE), the model was utilized to determine the least cost mix of existing and new generating assets that meets demand (electric load) over time and also meets regulatory and reliability requirements. In dispatch mode, the model was utilized to assess how a portfolio of assets will perform under a fixed set of market conditions.

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

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

In order to perform both the required deterministic (scenario based) and probabilistic (stochastic) modeling, Pace Global developed five scenarios and a set of probability distributions for key market driver variables. These include both forecasts of each variable under the five conditions and probabilistic distributions for demand growth (load), fuel costs (natural gas and coal), environmental compliance costs (carbon) and capital costs. In the sections below is a description of how these forecasts and distributions were developed.

7.2 REFERENCE CASE SCENARIO

Vectren developed a Reference Case forecast of key market drivers that collectively represent the expected or most likely to occur path forward for each input variable. For key assumptions, including natural gas prices, coal prices and capacity prices, a range of views from four 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 (2020-2021), the Reference Case assumes an overall positive sales growth as Vectren adds general service and large customer growth. Residential customer annual consumption is expected to decline slightly to 2021 before rising again in the medium-term and long-term. Large commercial and industrial (C&I) customers are expected to increase both in numbers and consumption, also with a partial offset of this growth by increasing efficiency. As a result, average energy sales grow at 2.2% for 2019-2021.

Natural gas prices are expected to decline in 2020 compared to 2019, as the oversupply situation from shale gas and associated gas production continues to dominate gas market dynamics. In the short-term, natural gas prices are expected to remain below $2.80/MMBtu.

Meanwhile, coal prices decline in the near-term as domestic markets remain soft. 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 2019 price of $1.78/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. Capacity additions in the form of efficient combined cycle gas turbine plants or fast-ramping simple cycle gas turbines grew rapidly over the past few years as merchant plants and utilities took advantage of low gas prices. The EIA in

its AEO 2020 report anticipates a continued pace of capacity additions over the next few years, balanced between gas plants and renewables.[37]

Medium Term: In the medium-term (2022-2028), the Reference Case reflects the assumption that a carbon price will be implemented on the national level and will begin in 2027 at approximately $4/short ton of CO_2 (in real 2018$). CO_2 prices in California and in Northeast states participating in RGGI are expected to harmonize with the broader U.S. market at this time. In this IRP, Vectren is accounting for both direct CO_2 emissions and CO_2-equivalent (CO_2e) emissions for the life cycle of assets.

In the medium-term 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.

Natural gas prices at the Henry Hub in the medium-term will continue to be low but will rise over time, with the consensus forecast anticipating prices in the $3.00-$3.50/MMBtu range. Low prices tend to be self-correcting, resulting in restricted production and reduced gas supply. Coupled with LNG export capacity growing through 2023 and increased industrial consumption in many parts of the country, overall demand is expected to rise and gas markets to tighten. This is especially true in the premium Gulf Coast market, where much of the demand is materializing, increasing prices beginning in 2021.

Coal prices in the Illinois Basin are expected to continue to decline gently in the medium-term, as the modest export market is unable to compensate for declining domestic demand. Consensus Illinois Basin prices at the mine are low, averaging $1.60/MMBtu over the study period, with a slight decline over time.

[37] https://www.eia.gov/outlooks/aeo/

Power prices, which are an output of the AURORA model for MISO Zone 6, continue to move upward moderately as natural gas prices increase from the currently low levels. As 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.

Coal retirements in the Reference Case mean no emissions from retired units, which contribute to lowering total CO_2 (and CO_2e) emissions. Coal plant retirements will continue to be driven by plant-specific going-forward economics, which rise as a national CO_2 price is assumed to begin in 2027. Meanwhile, capacity additions in the medium-term are expected to come from natural gas combined cycle plants as well as solar and wind facilities.

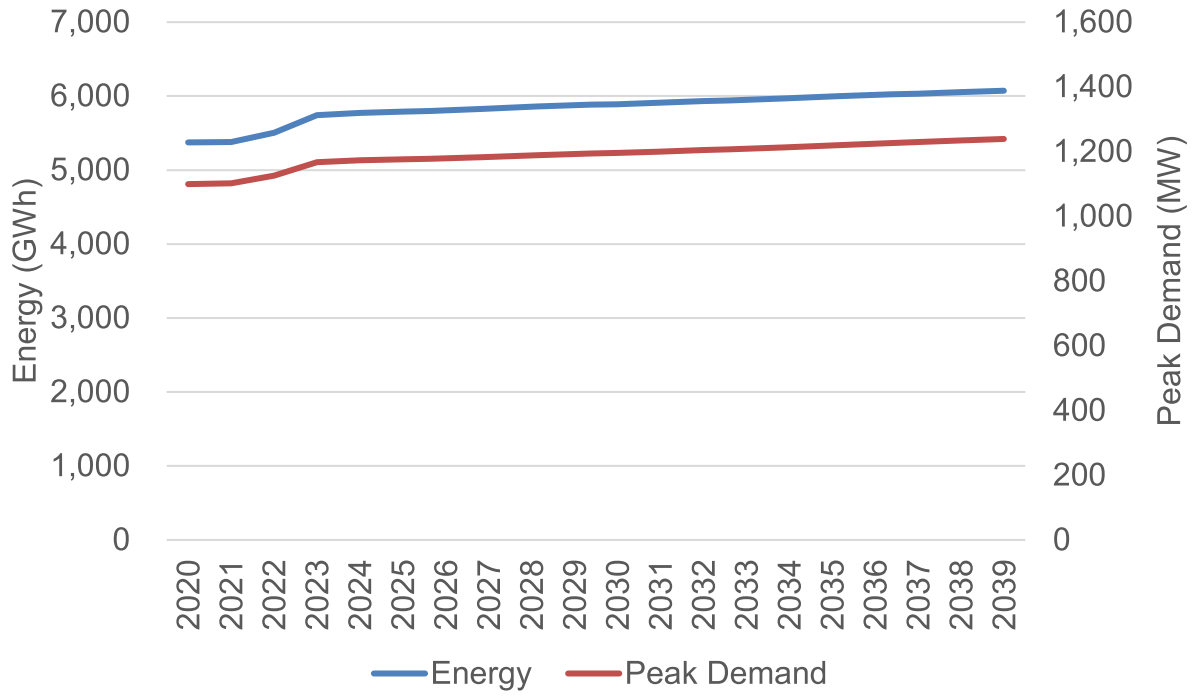
Long Term: In the long-term (2029-2039), the suite of market outcomes and drivers in the Reference Case settles into a pattern of moderate growth based on a well-balanced market. Energy sales grow at a moderate pace (0.6% CAGR for 2020-2039). The consensus forecast for Henry Hub has prices reaching $4/MMBtu by 2036 (in real 2018$), while ILB coal prices at the mine decline to $1.58/MMBtu by 2039 (in real 2018$). Market participants have enough time to adapt and adjust as regulatory compliance costs increase, helping to keep CO_2 prices moderate albeit rising to approximately $15/short ton by 2039 (in real 2018$). 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 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 Vectren service territory was developed for Vectren 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.[38] For more information, please see Section 4 Customer Energy Needs. 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.

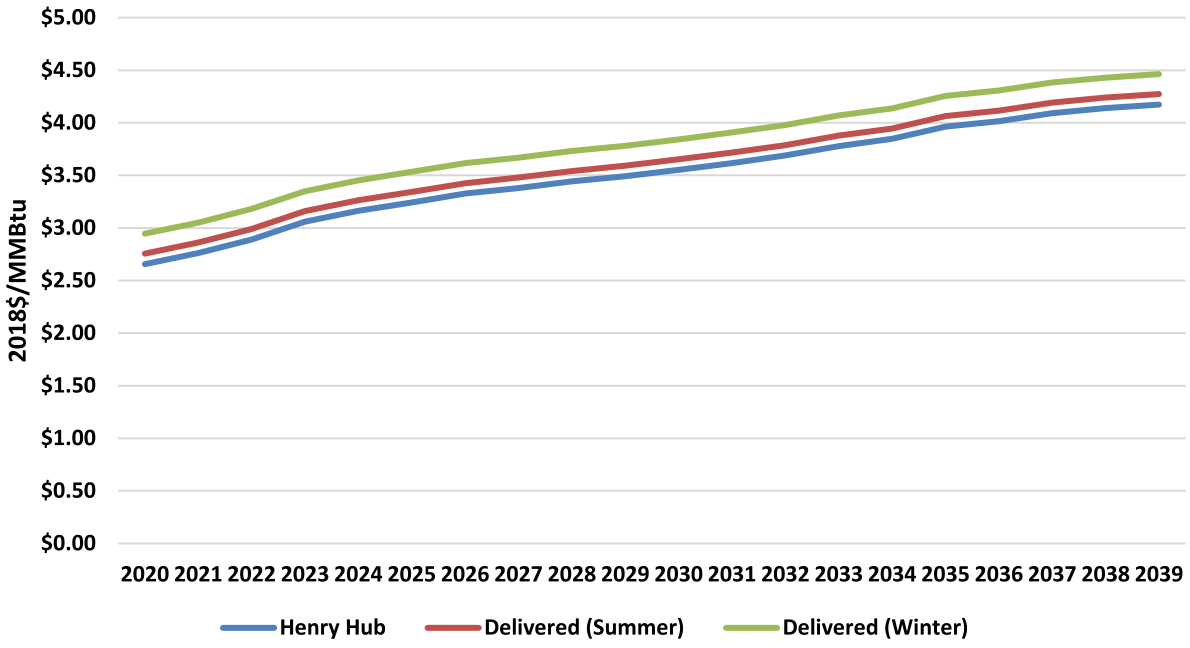
Figure 7.1 – Reference Case Vectren Load Forecast (MWh and MW)



[38] 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

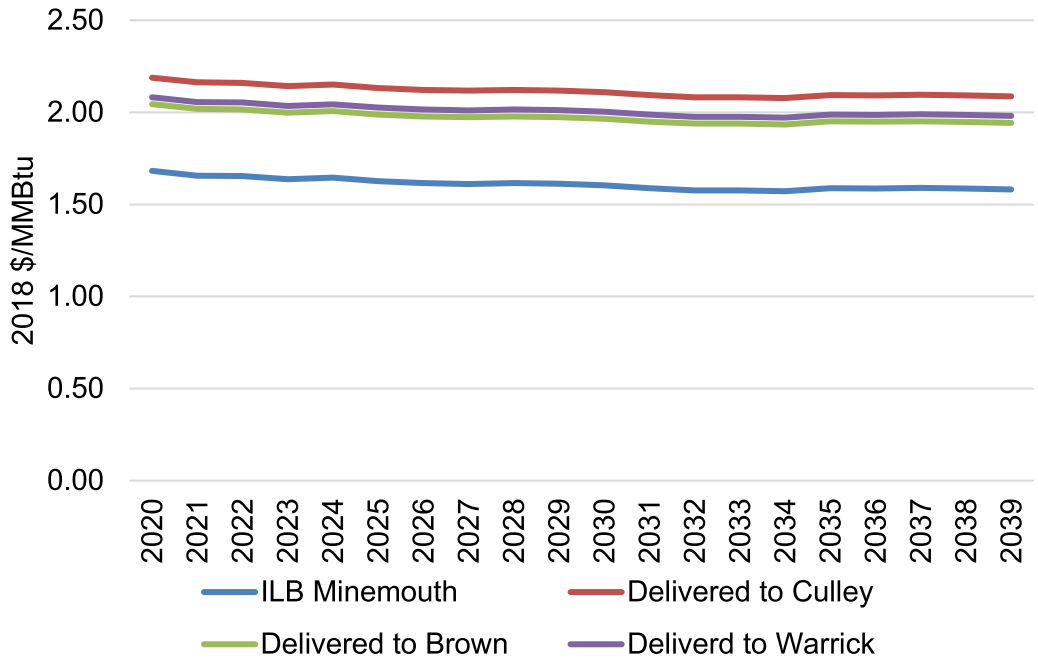
For both natural gas and coal Vectren used a "consensus" Reference Case view of expected prices by averaging forecasts from several sources. For natural gas and coal, forecasts from PIRA, Wood Mackenzie, Pace Global, ABB, & EVA were averaged. For capacity, Vectren used a consensus forecast, using Pace Global, ABB and Wood Mackenzie[39]. This helps to capture views from several experts and allows Vectren to be more transparent in the planning process. Delivered natural gas prices are $0.10-$0.29 higher than Henry Hub due to seasonal transportation tariffs.

Figure 7.2 – Reference Case Natural Gas Price Forecast (2018$/MMBtu)



[39] Vectren did not have access to a capacity forecast from PIRA or EVA

Figure 7.3 – Reference Case Coal Price Forecast (2018$/MMBtu)

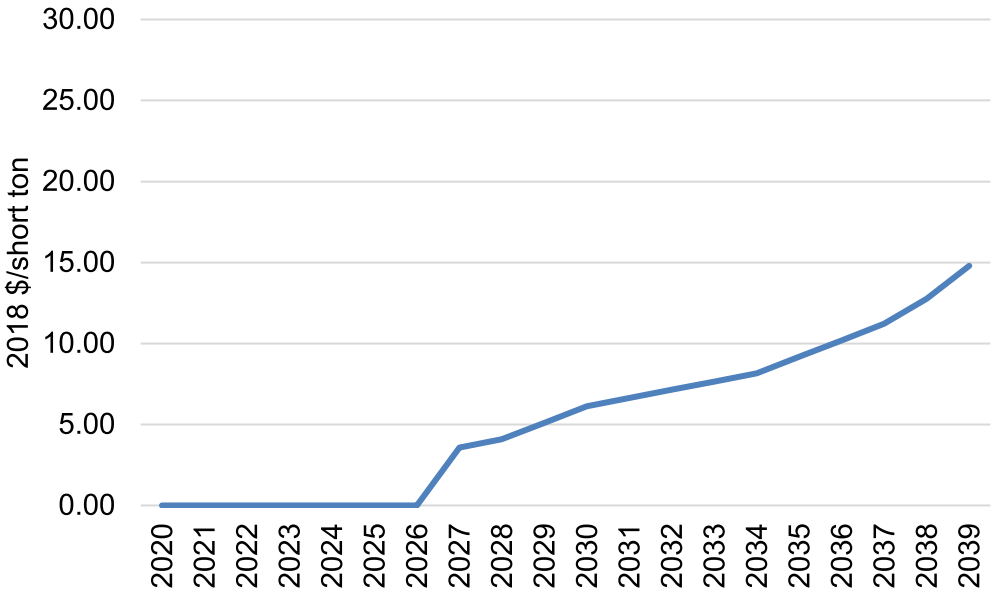


No comprehensive national legislation of carbon emissions exists in the United States currently. Efforts to enact federal policy covering carbon emissions from major sources have occurred over the years. This included efforts by the U.S. Congress to pass a national cap-and trade regime, the EPA's regulation of GHG emissions from new and existing power generators which culminated in the current ACE rule, 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 and per stakeholder request, a moderate price on CO_2 emissions from fossil generators is assumed in the Reference Case. This outlook includes a national carbon price to become effective in 2027, covering emissions

from electric generating units in the United States. Pace's EBA's CO_2 price projections in the Reference Case are presented in the figure below.

Figure 7.4 – Reference Case CO_2 Price Forecast (2018$/short ton)



Capital costs in the near to midterm (through 2024) were based on Tier 1 bids, as described in Section 6.1.5 Grouping. As described in Section 6, non-renewable capital costs were developed by Burns & McDonnell, while long term solar, wind and battery storage costs were developed using a consensus forecast from Burns & McDonnell, Pace Global and the NREL ATB 2018. Long-term capital costs for storage and solar + storage were adjusted to reflect bid pricing in the near term and then the capital cost indexes were used to adjust prices beyond the bid period. The long-term cost for solar was in line with the consensus forecast and therefore was not adjusted. Forward capital cost estimates can be found in Figure 6-21.

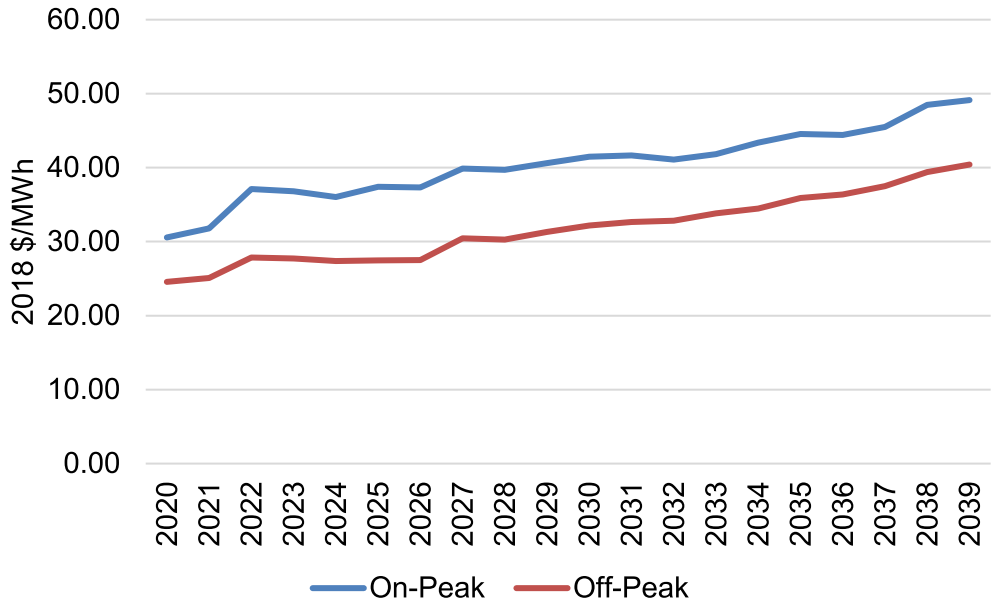
7.2.2 Energy Prices

On- and off-peak (day ahead) power price forecasts were a modeling output developed by Pace Global using the Reference Case assumptions described above, together with

Pace Global' s view of the greater MISO market, in the AURORAxmp power dispatch model.

Vectren's modeling does assume curtailment of resources when more energy is produced than is needed to meet customer load and Vectren's All-Source RFP sought operational control of resources.

Figure 7.5 – Reference Case Power Price Forecast (2018$/MWh)



Levelized DSM costs were developed by utilizing the 2019 MPS and the annual supply curves to develop costs for each energy efficiency bundle, as described in Section 6-32 Energy Efficiency Reference Case.

7.2.3 Environmental Regulations

The current modeling analysis primarily focused on evaluation of alternatives to comply with the CCR, ELG, 316(b) and ACE rule requirements. For CCR and ELG compliance, conversion to dry or closed loop bottom ash handling, wastewater treatment and landfill construction options were evaluated. For 316(b) compliance, based on site-specific

considerations, standard mesh and fish friendly screens and fish return systems were assumed. 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 and vendor bids.

7.2.3.1 Effluent Limitations Guidelines (ELG)

A. B. Brown: ELG related changes 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. ($138M)

F. B. Culley: Required plant upgrades include conversion to dry bottom ash, FGD wastewater treatment and access to a landfill that can handle dry ash. ($62M)

For Warrick Unit 4, Vectren 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 that ash ponds would be closed at the end of their useful life. The timing of the closures are based on forced closure (i.e. exceedance of GWPS and failure of aquifer location restriction) and whether alternative disposal capacity is available. The base cost for the closures does not change regardless of future generation. In order to continue operating coal-fired units, the A.B. Brown facility will potentially need to construct a new CCR rule compliant landfill capacity and a new CCR rule compliant pond, both of which depend on the scrubber technology utilized in the future. Vectren 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, 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). Vectren assumed that ACE compliance would begin in 2024.

Figure 7.6 – ACE Cost

Unit	Total ACE Upgrade Cost (2019$)
A.B. Brown 1	$10 Million
A.B. Brown 2	$10 Million
F.B. Culley 2	$26 Million
F.B. Culley 3	$30 Million
Warrick 4	N\A[40]

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 (CWISs) 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. Warrick is required to install modified travelling screens and a fish handling and return system at Warrick. Vectren is responsible for its share of total capital.

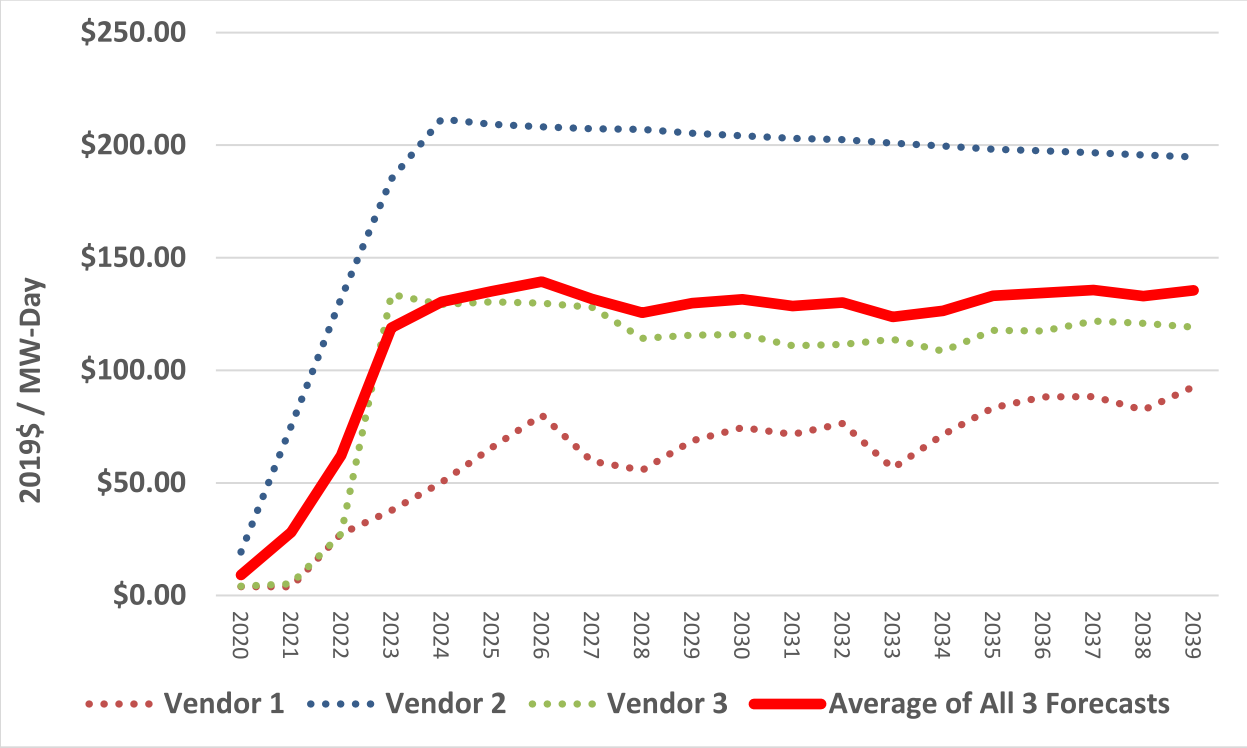
7.2.3.5 Market Capacity Price

The MISO capacity price has been difficult to predict as indicated by the volatile price history shown. This is especially true when analyzing the clearing price for the entire MISO-region. The clearing price in neighboring zones can be drastically different than

[40] In this analysis it is assumed joint operations of Warrick 4 ends in 2023 or 2026; In the 2026 scenario there is a cost of ~$1 million

Zone 6's and becomes an important consideration as Zone 6 imports capacity to meet its planning reserve margin requirement. Nonetheless, it is necessary for analysis purposes to have a capacity market price assumption to be included in the IRP modeling process. For illustrative purposes only, for every $1 per MW-day increase in the auction clearing price, there is an approximate $438,000 ($1 x 1,200 MW x 365 days) annual cost of capacity impact to Vectren customers. Some capacity will be bought or sold nearly every year since load and planning reserve margin requirements vary while most supply side resources, such as generating units, come in large blocks with 30+ year expected lifetimes. Vectren used a consensus forecast, utilizing Pace Global, ABB and Wood Makenzie for Reference Case MISO Indiana capacity prices for modeling purposes.

Figure 7.7 – Capacity Market Value Forecast (2019$/MW-Day)



For reference, MISO has set the Cost of New Entry (CONE) for Zone 6 in the 2020-2021 planning year at $255/MW-Day which sets the maximum offer and clearing price in the annual capacity auction. While the forecast used in this analysis is significantly

lower than CONE it is necessary to consider that capacity prices could reach this level making long term reliance on the capacity market a risk that should be avoided. This consideration is even more relevant due to Zone 7, the lower peninsula of Michigan, clearing at CONE during this year's PRA.

It is a combination of the MISO warnings, the widely varying Consultant forecasts and the risks associated with an illiquid market that suggests to Vectren that the best way to mitigate the capacity market risk is through building Combustion Turbines for capacity rather than rely heavily on the market.

7.2.4 Additional Modeling Considerations

Vectren received approval in 2019 from the Commission to upgrade F.B. Culley 3, Vectren's most efficient coal unit, for continued operations. As such, the unit was modeled with continued operations throughout the planning period. As stated in that case, there is a premium for resilience and diversity with continuing to run the Culley unit. Based on updated reference case modeling in this IRP, that premium is estimated to be about ~0.5% in total NPV for continuing to run the plant through 2034. Vectren has chosen to continue operating this unit for the resiliency that it provides. All other coal units could retire economically within the model beginning December 31, 2023.

Modeling also included other fixed considerations. All candidate portfolios were designed to include the first five selectable energy efficiency bins, corresponding to 1.25% of energy efficiency, in the near-term years of 2021-2023. The model also included one fixed low-income bundle and one fixed demand response bundle (an air conditioning direct load control measure to a smart thermostat measure). Vectren's coal units were modeled to dispatch to LRZ6 on the basis of full variable costs (fuel, emissions, VOM) in the years 2019-2023, while dispatching to serve native load on the basis of fuel only in these same years. All coal units (whether selected to continue or not) were modeled to dispatch to full variable costs to LRZ6 and Vectren from 2024 through the end of the forecast period (2039). Long term annual capacity market purchases were limited to ~180 MW.

While a dynamic peak capacity credit (automatically adapting to the penetration level of solar and wind resources in MISO) proved to be challenging to implement in Aurora, Vectren's modeling efforts did include a seasonal, declining peak capacity credit for both solar and wind resources. Summer solar peak capacity credit began at 29% in 2023 (the first year in which new solar resources are available) and declined to 17% by 2039, while winter solar peak capacity credit began at 7% in 2023 and declined to 4% in 2039. Summer wind peak capacity credit began at 7.23% in 2022 (the first year in which new wind resources are available) and declined to 6.62% by 2039, while winter wind peak capacity credit began at 16.1% in 2022 and declined to 14.74% in 2039. Battery storage was modeled with a 95% peak capacity credit. Non-bid solar and Non-bid wind resources were not permitted until 2025 after short-term renewable and storage PPAs were no longer available.

Additional modeling parameters were included to account for logistical, commercial and operational limitations. These included limiting wind energy resources to 400 MW per year, wind plus storage resources to 150 MW per year, solar photovoltaic resources to 500 MW per year, solar plus storage resources to 150 MW per year, lithium-ion battery storage resources to 300 MW per year and flow battery storage to 400 MW per year. Combined cycle gas resources were limited to one unit per year, while simple cycle gas turbine resources were limited to a total of three units. Combined heat and power (CHP), reciprocating engines and aeroderivative gas turbines were excluded as resource options on the basis of lack of a dedicated facility for steam in the case of CHP and for technical considerations (for example, gas pipeline pressure requirements and cost) in the case of aeroderivatives.

7.3 ALTERNATE SCENARIOS

In order to develop several alternative scenarios for its IRP process, Vectren used a construct that allowed for increasing regulatory restrictions 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 were created with increasing order of regulatory restriction included the Low Regulatory scenario, the High Technology scenario, the 80% Reduction in CO_2 scenario and the High Regulatory scenario. Pace Global provided the qualitative descriptions and quantitative inputs for each of these scenarios, which were based on collaboration between Vectren, Pace and stakeholders.

Each of the four alternative scenarios provided a framework of market inputs in which a least cost portfolio solution was developed. Of the four scenario based portfolios that were developed, only the High Technology portfolio was selected for further analysis.

The High Technology portfolio provided a useful boundary condition on the Reference Case, relying on a second combustion turbine unit, 1,146 MW of solar, 300 MW of wind and 176 MW of storage. The other three alternative scenario based portfolios included significantly greater renewable resources in their respective market scenario conditions than needed to serve Vectren customers under reference case conditions. In these three scenarios that were not selected for further analysis, the portfolios selected as least cost assumed large quantities of off-system sales in order to reduce portfolio costs. The high level of sales associated with these portfolios precluded them from further consideration as that was a significant issue raised in several of the portfolios in the 2016 study in the Director's report.

For example, the Low Regulatory portfolio included higher load and higher gas prices than in the Reference Case. However, the portfolio (optimized to those different market conditions) included 2,146 MW of solar, 2,700 MW of wind, 126 MW of battery storage and a relatively heavy reliance on capacity market purchases, in addition to F.B. Culley 3 and one new CT.

The least cost 80% Reduction of CO_2 portfolio included 1,946 MW of solar, 3,050 MW of wind and 392 MW of battery storage. Due to the significant increase in late-term renewables buildout, this portfolio saw annual net energy sales climb from 2,500,000 MWhs in 2033 to over 9,300,000 MWhs by 2039.

The least cost High Regulatory portfolio included 2,956 MW of solar, 3,600 MW of wind and 618 MW of battery storage. Due to the heavy buildout of renewables, this portfolio reached 10,000,000 MWh of annual net energy sales by 2029 and stayed above this level for the remainder of the study period.

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 Low Regulatory

The Low Regulatory scenario is meant to be a lower boundary scenario in which there is a general laissez-faire attitude toward regulations. In the Low Regulatory scenario, only the ACE rule is included for CO_2 regulation and remains in place throughout the forecast. Indiana implements a lenient interpretation of the rule. ELG is partially repealed with bottom ash conversions not required for some smaller units and is delayed for two years (this does not apply to F.B. Culley 3).

In this scenario, fewer regulations are expected to result in a better economy and higher load. Gas prices are expected to move upward with increased demand, while coal prices continue to remain at Reference Case levels as demand for coal continues to decline nationally due to investor pressure and demand for cleaner alternatives. Technology capitals costs are expected to continue to decline at Reference Case levels.

Energy efficiency costs are expected to net to the Reference Case level. There is downward pressure with fewer codes and standards being implemented, leaving some low hanging fruit, but upward pressure with increasing load, netting to no change from the Reference Case level.

7.3.1.2 High Technology

The High Technology scenario was constructed to be indicative of significant advances in energy storage technology, renewable energy deployment, emissions reduction and CO_2 removal technology, high efficiency gas-fired generation and natural gas extraction productivity. Overall, there are significant developments in technologies that improve energy efficiency, which helps to mitigate the load growth that might otherwise be expected in a high technology scenario with robust economic growth.

The High Technology scenario assumes that technology costs decline faster than in the Reference Case, allowing renewables and battery storage to become more competitive. A relatively low CO_2 tax is implemented in this scenario. The economic outlook is better than in the Reference Case as lower technology costs and lower energy prices offset the impact of the CO_2 tax. The increased demand for natural gas is more than met with advances in key technologies that unlock more shale gas, increasing supply and lowering gas prices relative to the Reference Case. There is less demand for coal, which results in lower prices relative to the Reference Case. In addition, utility-sponsored energy efficiency costs rise early in the forecast but ultimately fall back to below Reference Case 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 increased electric vehicle sales and higher adoption of rooftop distributed solar and battery storage, which trend towards highly efficient electric heat pumps in new homes.

7.3.1.3 80% CO_2 Reduction by 2050

The 80% CO_2 Reduction by 2050 scenario assumes that a carbon cap regulation is implemented, which mandates an 80% reduction of CO_2 by 2050 from 2005 levels. A glide path is then set based on a gradual ratcheting-down of CO_2 emissions and an increasing CO_2 allowance cost.

In this scenario, load decreases as the costs for energy and backup power increase and as the energy mix transitions into areas such as increased electrification. In this scenario, regulations on methane emissions initially drive up gas prices, but are partially offset by increased supply. The price of natural gas remains on par with the Reference Case. However, there is less demand for coal, which drives prices lower than the Reference Case. Some large and efficient coal plants remain as large fleets can comply with the regulation on a fleet wide basis.

Renewable energy and battery storage technologies are widely implemented to help meet the mandated CO_2 reductions. Despite this demand, costs are lower than the Reference Case due to subsidies or similar public support to address climate change concerns. Market-based solutions are implemented to lower CO_2. Innovation continues to occur but is offset by more codes and standards with no incentives. As a result, energy efficiency costs rise.

7.3.1.4 High Regulatory

The High Regulatory scenario is characterized by a more heavily regulated path. The High Regulatory path is indicative of the following plausible circumstances relative to the Reference Case:

- A much higher cost for compliance with emissions controls, which begins virtually immediately in 2022 at $50/short ton of CO_2;
- More renewable adoption pushed through via mandates;
- Additional regulations on carbon on the horizon after 2030 that are higher than in the Reference Case, including a potential expansion of carbon costs not only at

the upstream level (which is relatively efficient to administer across a few thousand producers) but also on the downstream level (which is much less efficient to administer across millions of consumers, a policy that is adopted to force through more rapid change);

- Greater adoption of distributed generation in the form of solar and combined heat and power; and
- Restrictions on fracking and fugitive methane emissions that limit gas supply growth, drive up gas prices and result in an additional push and economic case for renewable energy.

The social cost of carbon is implemented via a high CO_2 tax early in the scenario. Monthly rebate checks (dividends) help to redistribute the revenues from the tax to American households based on number of people in the household. Furthermore, a fracking ban is imposed, driving up the cost of natural gas to historical levels last seen in the pre-shale boom era (pre-2008) in the long-term as supply dramatically shrinks (quantitatively, the price path is +2 standard deviations above current levels). For coal, a strong decline in demand puts downward pressure on coal prices.

The economic outlook remains at the Reference Case level as any potential benefit of the CO_2 dividend is offset by the drag on the economy imposed by additional regulations, including the fracking ban. Innovation occurs as renewables and battery storage are widely implemented to avoid paying high CO_2 prices, 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.

7.3.2 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.

- Stochastic 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 natural gas prices, CO_2 prices, coal prices, average and peak load for Vectren as well as surrounding markets (MISO, PJM and SERC) and capital costs for renewables, storage and fossil technologies.

7.3.2.1 Stochastic Distributions

In order to perform the probabilistic modeling, also known as stochastic analysis, a set of probability distributions were required for the key market driver variables described above (fuel, emissions, load and capital costs). These probability distributions were developed from a simulation that creates 200 future paths for each stochastic variable. The following sections describe the methodologies for developing these stochastic variables, with additional detail explained in the Technical Appendix 11.6.

7.3.2.1.1 Load Stochastics

To account for electricity demand variability that derives from economic growth, weather, energy efficiency and demand side management measures, Pace Global developed stochastics around the load growth expectations for the Vectren control area and the neighboring ISO zones, including MISO, PJM and SERC. Pace Global' s long-term load forecasting process is a two-step process that captures both the impact of historical load drivers such as economic growth and variability of weather and the possible disruptive impacts of energy efficiency penetration in constructing the average and peak demand outlook. Pace Global benchmarked the projections against MISO-sponsored load

forecasting studies that are conducted by independent consultants, institutions and market monitors and then released into the public domain.

7.3.2.1.2 Gas Stochastics

Pace Global developed natural gas price stochastic distributions for the benchmark Henry Hub market point. These stochastic distributions are first based on the consensus Reference Case view of natural gas prices with probability bands developed then based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility. For the period 2019-2022, volatility calculated from the past three years of price data is used. For 2023-2025, volatility calculated from the past five years is used. For 2026-2039, volatility calculated from the past 10 years is used. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95th percentile probability bands are driven by increased gas demand (e.g., coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization relatively low as well as few to no new environmental regulation around power plant emissions.

7.3.2.1.3 Coal Stochastics

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

7.3.2.1.4 Emissions Stochastics

Pace Global developed uncertainty distributions around carbon compliance costs, which were used in Aurora to capture the inherent risk associated with regulatory compliance

requirements. The technique to develop carbon costs distributions, unlike the previous variables, is based on projections largely derived from expert judgment, as there are no national historical data sets (only regional markets in California and the Northeast) to estimate the parameters for developing carbon costs distributions.

7.3.2.1.5 Capital Cost Stochastics

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

7.3.2.1.6 Cross-Commodity Stochastics

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

historic volatility to calculate an integrated set of CO_2 and natural gas stochastic price forecasts.

7.3.2.2 Model Inputs

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

Figure 7.8 – Vectren Peak Load (MW) Alternate Scenarios

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,115	1,115	1,115	1,115	1,115
2020	1,100	1,100	1,100	1,100	1,100
2021	1,102	1,102	1,102	1,102	1,102
2022	1,126	1,146	1,146	1,084	1,126
2023	1,168	1,191	1,191	1,066	1,168
2024	1,173	1,235	1,235	1,049	1,173
2025	1,176	1,303	1,303	1,055	1,176
2026	1,179	1,325	1,325	1,045	1,179
2027	1,183	1,322	1,322	1,036	1,183
2028	1,189	1,348	1,348	1,028	1,189
2029	1,192	1,338	1,338	1,035	1,192
2030	1,196	1,337	1,337	1,059	1,196
2031	1,200	1,356	1,356	1,055	1,200
2032	1,205	1,371	1,371	1,055	1,205
2033	1,209	1,386	1,386	1,056	1,209
2034	1,214	1,356	1,356	1,051	1,214
2035	1,219	1,379	1,379	1,051	1,219
2036	1,225	1,379	1,379	1,065	1,225
2037	1,229	1,383	1,383	1,060	1,229
2038	1,234	1,386	1,386	1,076	1,234
2039	1,239	1,391	1,391	1,062	1,239

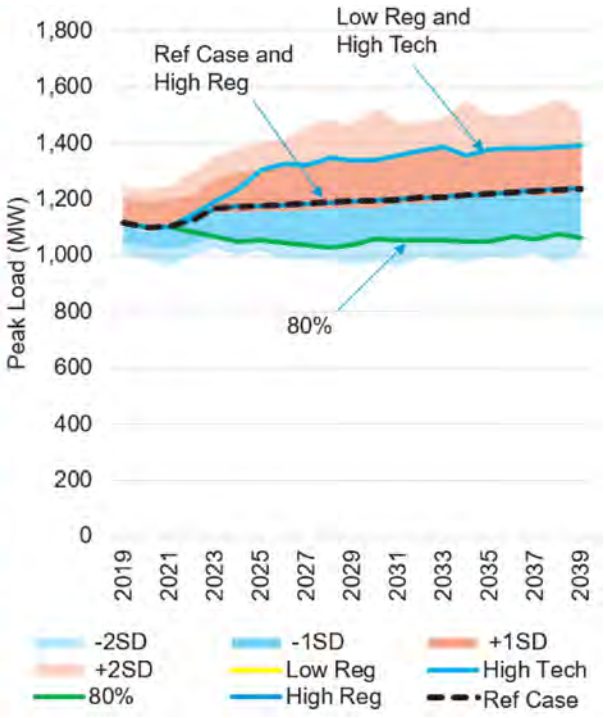


Figure 7.9 – Coal (Illinois Basin) Alternate Scenarios (2018$/MMBtu)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1.78	1.78	1.78	1.78	1.78
2020	1.68	1.68	1.68	1.68	1.68
2021	1.66	1.66	1.66	1.66	1.66
2022	1.65	1.65	1.57	1.57	1.57
2023	1.64	1.64	1.49	1.49	1.49
2024	1.64	1.64	1.41	1.41	1.41
2025	1.63	1.63	1.27	1.27	1.27
2026	1.62	1.62	1.29	1.29	1.29
2027	1.61	1.61	1.25	1.25	1.25
2028	1.62	1.62	1.25	1.25	1.25
2029	1.61	1.61	1.25	1.25	1.25
2030	1.60	1.60	1.25	1.25	1.25
2031	1.59	1.59	1.25	1.25	1.25
2032	1.58	1.58	1.25	1.25	1.25
2033	1.58	1.58	1.25	1.25	1.25
2034	1.57	1.57	1.25	1.25	1.25
2035	1.59	1.59	1.25	1.25	1.25
2036	1.59	1.59	1.25	1.25	1.25
2037	1.59	1.59	1.25	1.25	1.25
2038	1.59	1.59	1.25	1.25	1.25
2039	1.58	1.58	1.25	1.25	1.25

A price floor is set at $1.25/MMBtu

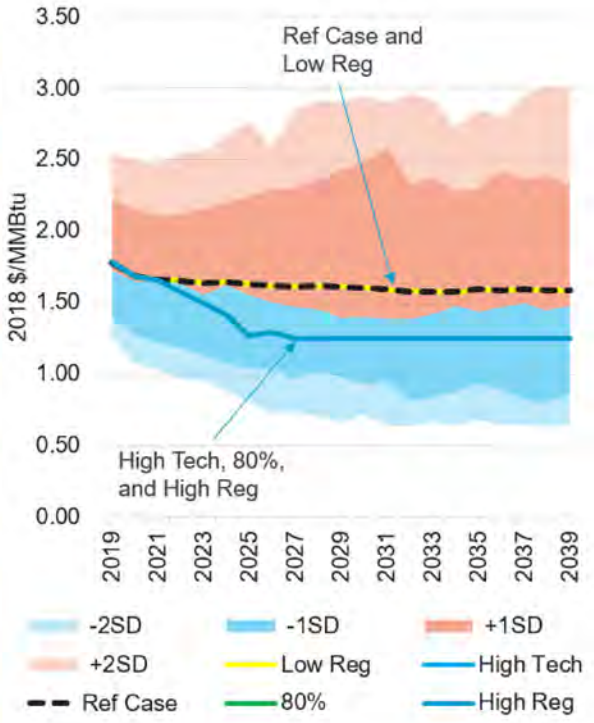


Figure 7.10 – $C0_2$ Alternate Scenarios (2018$/ton)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	0	0	0	0	49.46
2023	0	0	0	0	50.40
2024	0	0	0	0	51.34
2025	0	0	1.20	3.57	52.28
2026	0	0	1.44	4.08	53.23
2027	3.57	0	2.06	5.10	54.17
2028	4.08	0	2.28	6.12	55.11
2029	5.10	0	2.38	6.63	56.05
2030	6.12	0	2.68	7.14	56.99
2031	6.63	0	2.94	7.65	57.94
2032	7.14	0	3.17	8.16	58.88
2033	7.65	0	3.89	9.18	60.06
2034	8.16	0	4.49	10.20	61.23
2035	9.18	0	5.46	11.22	62.41
2036	10.20	0	6.01	12.75	63.59
2037	11.22	0	6.85	14.79	64.77
2038	12.75	0	7.52	17.34	65.94
2039	14.79	0	8.50	19.89	67.12

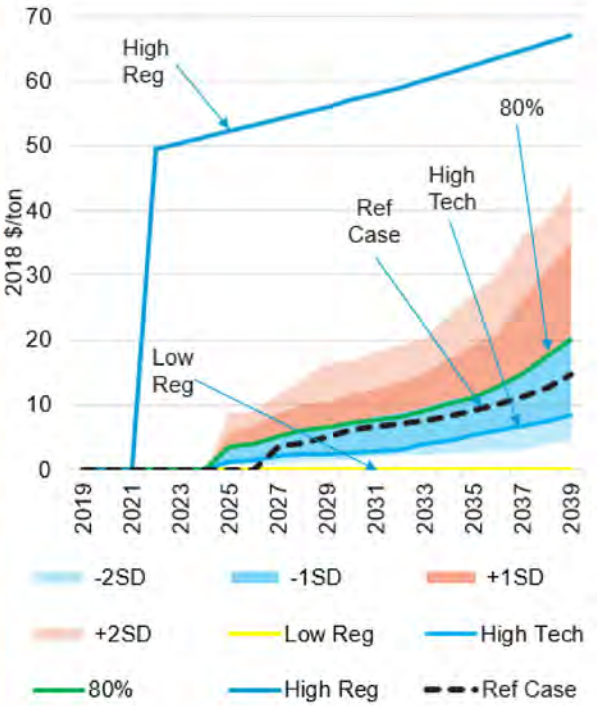


Figure 7.11 – Natural Gas (Henry Hub) Alternate Scenarios (2018$/MMBtu)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	2.77	2.77	2.77	2.77	2.77
2020	2.66	2.66	2.66	2.66	2.66
2021	2.76	2.76	2.76	2.76	2.76
2022	2.89	3.46	3.01	2.89	3.58
2023	3.06	4.10	2.82	3.06	4.39
2024	3.16	4.75	2.64	3.16	5.21
2025	3.24	5.12	2.33	3.24	6.03
2026	3.33	5.27	2.08	3.33	7.14
2027	3.38	5.20	2.13	3.38	7.10
2028	3.44	5.45	2.06	3.44	7.43
2029	3.49	5.62	2.04	3.49	8.37
2030	3.55	5.77	2.12	3.55	7.53
2031	3.62	5.60	2.13	3.62	7.17
2032	3.69	5.76	1.97	3.69	7.89
2033	3.78	5.95	2.02	3.78	8.40
2034	3.85	6.02	1.95	3.85	7.49
2035	3.96	6.12	2.12	3.96	8.95
2036	4.02	6.64	2.12	4.02	9.29
2037	4.09	6.23	2.07	4.09	8.75
2038	4.14	6.77	2.19	4.14	9.07
2039	4.17	6.85	2.20	4.17	8.63

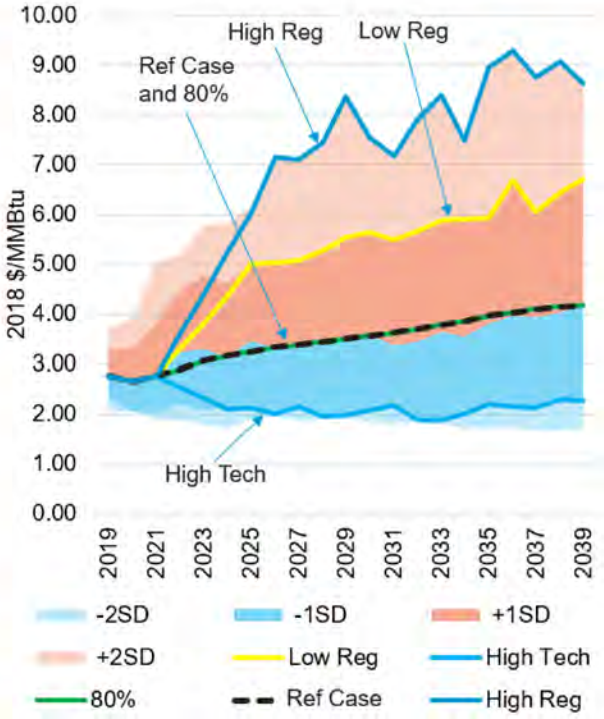


Figure 7.12 – Solar Capital Costs Alternate Scenarios(100 MW) (2018 $/kW)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,384	1,384	1,255	1,255	1,255
2020	1,305	1,305	1,160	1,160	1,160
2021	1,237	1,237	1,093	1,093	1,093
2022	1,198	1,198	1,043	1,043	1,043
2023	1,179	1,179	1,008	1,008	1,008
2024	1,161	1,161	996	996	996
2025	1,143	1,143	954	954	954
2026	1,124	1,124	956	956	956
2027	1,106	1,106	943	943	943
2028	1,089	1,089	949	949	949
2029	1,072	1,072	921	921	921
2030	1,057	1,057	887	887	887
2031	1,041	1,041	878	878	878
2032	1,028	1,028	871	871	871
2033	1,016	1,016	858	858	858
2034	1,003	1,003	817	817	817
2035	990	990	801	801	801
2036	981	981	790	790	790
2037	972	972	792	792	792
2038	962	962	789	789	789
2039	952	952	800	800	800

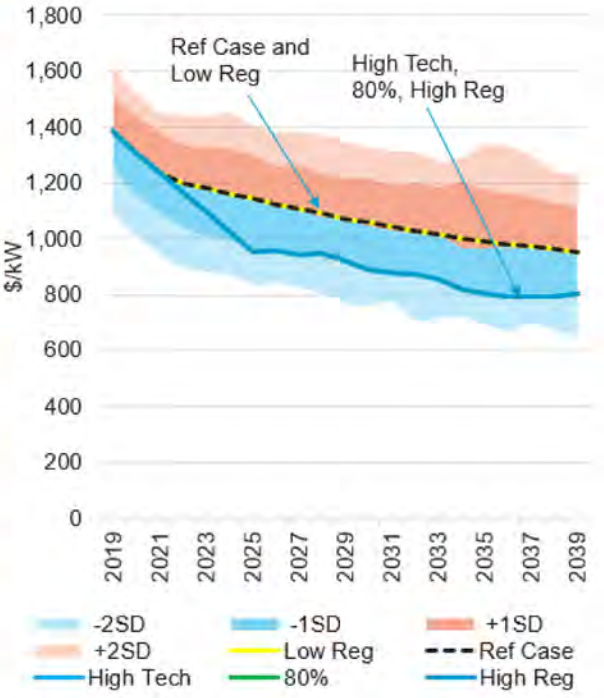


Figure 7.13 – Wind Capital Costs Alternate Scenarios (200 MW) (2018 $/kW)

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,334	1,334	1,334	1,334	1,334
2020	1,332	1,332	1,332	1,332	1,332
2021	1,330	1,330	1,330	1,330	1,330
2022	1,329	1,329	1,289	1,289	1,289
2023	1,328	1,328	1,249	1,249	1,249
2024	1,327	1,327	1,208	1,208	1,208
2025	1,326	1,326	1,167	1,167	1,167
2026	1,325	1,325	1,163	1,163	1,163
2027	1,324	1,324	1,123	1,123	1,123
2028	1,324	1,324	1,157	1,157	1,157
2029	1,324	1,324	1,160	1,160	1,160
2030	1,324	1,324	1,182	1,182	1,182
2031	1,324	1,324	1,152	1,152	1,152
2032	1,324	1,324	1,152	1,152	1,152
2033	1,324	1,324	1,166	1,166	1,166
2034	1,325	1,325	1,161	1,161	1,161
2035	1,326	1,326	1,139	1,139	1,139
2036	1,327	1,327	1,129	1,129	1,129
2037	1,328	1,328	1,142	1,142	1,142
2038	1,329	1,329	1,142	1,142	1,142
2039	1,330	1,330	1,143	1,143	1,143

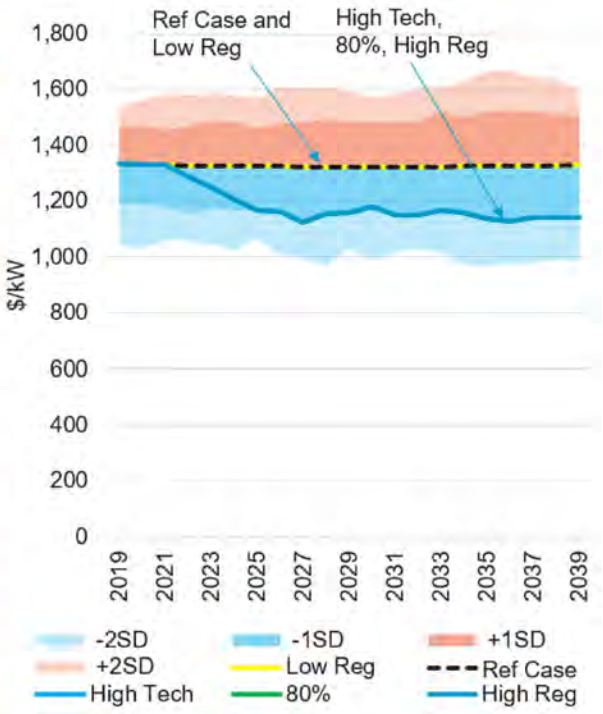
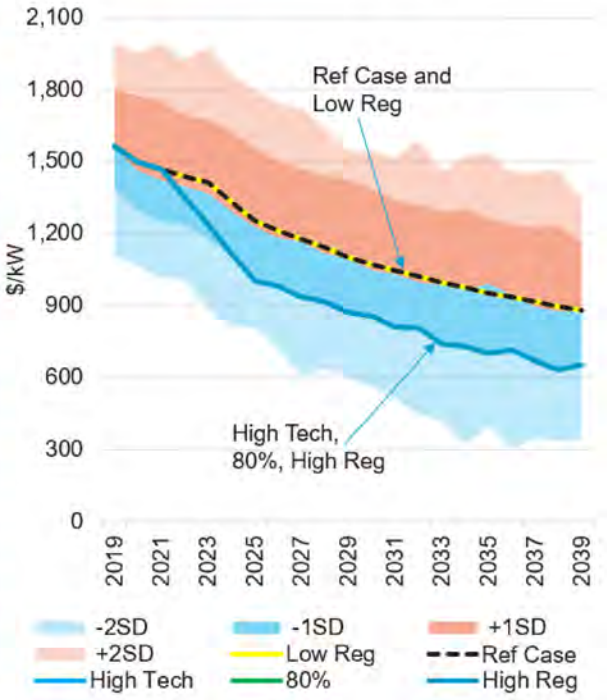


Figure 7.14 – Lithium-Ion 50 MW / 200 MWh Battery Storage Capital Costs Alternate Scenarios (2018$/kW)[41]

	Ref Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,562	1,562	1,390	1,390	1,390
2020	1,498	1,498	1,299	1,299	1,299
2021	1,467	1,467	1,247	1,247	1,247
2022	1,439	1,439	1,236	1,236	1,236
2023	1,412	1,412	1,178	1,178	1,178
2024	1,332	1,332	1,100	1,100	1,100
2025	1,252	1,252	1,001	1,001	1,001
2026	1,209	1,209	982	982	982
2027	1,175	1,175	936	936	936
2028	1,140	1,140	916	916	916
2029	1,103	1,103	869	869	869
2030	1,068	1,068	852	852	852
2031	1,044	1,044	811	811	811
2032	1,020	1,020	806	806	806
2033	996	996	739	739	739
2034	975	975	727	727	727
2035	951	951	699	699	699
2036	933	933	714	714	714
2037	915	915	669	669	669
2038	897	897	631	631	631
2039	878	878	654	654	654



[41] Note that storage costs were updated since the October 10th stakeholder meeting and are lower

SECTION 8
PORTFOLIO DEVELOPMENT AND EVALUATION

8.1 PORTFOLIO DEVELOPMENT

Vectren developed a wide range of portfolios for scenario modeling in the dispatch module of Aurora 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 2016 IRP, Vectren developed 15 "least cost" portfolios for evaluation that included the continuing use of coal plants (status quo) for comparative cost and performance benchmarking purposes, scenario-based portfolios optimized under widely varying market conditions, bridge portfolios designed to take advantage of existing resources during the transition to a generation fleet with many new resources, diversified portfolios with a balanced mix of generation technology types and renewables-focused portfolios designed with directed input from stakeholders. Each least cost portfolio was constructed with the option to include near-term solar, wind and battery storage options, from the All-Source RFP solicitation, while medium-term and long-term resource options were available for selection from a comprehensive technology assessment performed by Burns & McDonnell (with capital costs developed from a consensus view of prices from Burns & McDonnell, Pace Global and NREL for renewable and storage options). These resource portfolios were then selected on a least-cost basis using the LTCE module of the Aurora model. DSM resource options were also available for selection

8.1.1 Portfolio Strategies with Stakeholder Input

Vectren strived to take into consideration the many diverse interests of a broad range of stakeholders. Accordingly, several of the 15 candidate portfolios were developed with direct and indirect input from stakeholders. Three portfolios were designed to be focused on renewables, including a Renewables 2030 portfolio in which all fossil generation is retired at the end of 2029; a Renewables plus Flexible Gas portfolio, that includes closing F.B. Culley 3 by December 31, 2033 and excludes any new gas combined cycle plants; and an HB 763 portfolio modeled after a bill in the U.S. Congress that includes a CO_2 price in 2022 of $15, increasing by $10 per short ton each year (approximately $200 by 2039). Other portfolios, including the Business as Usual and Bridge portfolios, were designed to consider the interests of a separate set of stakeholders.

8.1.2 Least Cost Portfolio Construction

Each of the 15 strategies were utilized to construct portfolios in the Aurora model using a Least Cost Capacity Expansion module in AURORA with a cost minimization objective function. The scenario-based portfolios (Low Regulatory, High Technology, 80% Reduction of CO_2 and High Regulatory) each selected the lowest cost combination of assets assuming their respective market inputs. In Section 7 it is noted that three of those portfolios were eliminated from consideration because they employ greater capacity than needed in the form of renewable resources and rely on extensive off-system sales to reduce costs.

Other portfolios were determined by forcing certain design considerations for specific generating stations, including bridge options that include converting existing coal units into gas peaking units or extending the life of A.B. Brown coal units and then the model selected the least cost portfolio of remaining assets. Vectren also constructed in diverse energy portfolios with two sizes of gas combined cycle technologies and portfolios focused primarily on renewable and battery storage technologies. Utilizing this strategy allowed for a wide range of portfolios that were least cost portfolios using available resources, subject to initial design parameters in each strategy. All portfolios were also designed to include five (5) blocks of near-term (2021-2023) energy efficiency, which is equivalent to approximately 1.25% of eligible retail sales. Each portfolio description below details the optimized amount of EE selected.

8.1.3 Portfolio Descriptions

The following sections describe in detail designed portfolios (including bridge, diverse and renewables-focused portfolios). Figure 8.1 Portfolio Details shows a summary table of the build outs for each of the selected set of portfolios for consideration in the Risk Analysis. Note that the last line of each table shows long-term capacity market exposure under reference case conditions. Also, based on a sensitivity described in Section 8.2.2 near-term energy efficiency of 1.25% included in all portfolios.

Figure 8-1 – Portfolio Details

Year	Reference Case	Business as Usual to 2039	Business as Usual to 2029	Gas Conversion ABB1	Gas Conversion ABB1 + ABB2
2021-23	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency
2022	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)
2023	New Solar (731 MW), New Storage (126 MW)	New Solar (731 MW), New Storage (126 MW)	New Solar (731 MW), New Storage (126 MW)	New Solar (731 MW), New Storage (126 MW)	New Solar (731 MW), New Storage (126 MW)
2023	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Scrubber control on ABB1 and ABB2, Exit Warrick (150 MW)	Exit Warrick (150 MW)	Retire ABB2, FBC2, Exit Warrick (485 MW)	Retire FBC2, Exit Warrick (240 MW)
2024	New Combustion Turbine (236 MW)	-	-	ABB1 Conversion (245 MW)	ABB1+ABB2 Conversions (490 MW)
2024	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response
2024-26	0.75% Energy Efficiency	0.75% Energy Efficiency	0.75% Energy Efficiency	0.75% Energy Efficiency	0.75% Energy Efficiency
2027-39	0.75% Energy Efficiency	0.25% Energy Efficiency	0.50% Energy Efficiency	0.75% Energy Efficiency	0.50% Energy Efficiency
2029-30	-	-	Retire ABB1, ABB2, FBC2 (580 MW), New Combustion Turbine (236 MW)	-	-
2033-34	-	-	-	Retire ABB1, New Combustion Turbine (279 MW)	Retire ABB1+ABB2, New Combustion Turbine (279 MW)
2037-39	New Solar (250 MW)	-	-	-	-
2024-39	Avg Annual Capacity Mkt Purchases (137 MW)	No Capacity Market Purchases	Avg Annual Capacity Mkt Purchases (101 MW)	Avg Annual Capacity Mkt Purchases (133 MW)	Avg Annual Capacity Mkt Purchases (56 MW)

Year	Gas Conversion ABB1 + CCGT	Diverse Small CCGT	Diverse Medium CCGT	Renewables + Flexible Gas	Renewables 2030
2021-23	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency
2022	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)
2023	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (278 MW)
2023	Retire ABB2, FBC2, Exit Warrick (485 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)
2024	ABB1 Conversion (245 MW)	-	-	New Combustion Turbine (236 MW)	-
2024	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response
2024-26	0.75% Energy Efficiency	0.75% Energy Efficiency	0.75% Energy Efficiency	1.00% Energy Efficiency	0.75% Energy Efficiency
2025	-	New Small CCGT (433 MW)	New Medium CCGT (497 MW)	-	-
2026	New Small CCGT (433 MW)	-	-	-	-
2024-26	0.50% Energy Efficiency	0.50% Energy Efficiency	0.25% Energy Efficiency	1.00% Energy Efficiency	0.75% Energy Efficiency
2029-32	-	-	-	-	Retire FBC3, ABB3, ABB4 (427 MW), New Storage (360 MW), Solar (700 MW)
2033-34	-	-	-	Retire FBC3 (270 MW), New Combustion Turbine (236 MW)	New Solar (450 MW)
2024-39	Avg Annual Capacity Mkt Purchases (16 MW)	Avg Annual Capacity Mkt Purchases (23 MW)	Avg Annual Capacity Mkt Purchases (18 MW)	Avg Annual Capacity Mkt Purchases (135 MW)	Avg Annual Capacity Mkt Purchases (170 MW)

Year	HB 763	Low Regulatory	High Technology	80% Reduction of CO2 by 2050	High Regulatory
2021-23	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency	1.25% Energy Efficiency
2022	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)	New Wind (300 MW)
2023	New Solar (731 MW) New Storage (278 MW)	New Solar (731 MW) New Storage (278 MW)	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (202 MW)	New Solar (731 MW) New Storage (278 MW)
2023	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)	Retire ABB1, ABB2, FBC2, Exit Warrick (730 MW)
2024	New Landfill Gas (27 MW)	New Combustion Turbine (279 MW)	New Combustion Turbine (236 MW)	-	-
2024	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response	New Solar (415 MW) and Demand Response
2024-26	1.50% Energy Efficiency	1.25% Energy Efficiency	0.75% Energy Efficiency	0.75% Energy Efficiency	1.25% Energy Efficiency
2025	New Solar (550 MW) New Wind (650 MW) New Storage (50 MW)	-	New Combustion Turbine (236 MW)	-	New Solar (550 MW) New Wind (650 MW) New Storage (50 MW)
2026-39	New Solar (1,100 MW) New Wind (2,500 MW) New Storage (220 MW)	New Solar (1,000 MW) New Wind (2,400 MW)	-	-	New Solar (1,260 MW) New Wind (2,650 MW) New Storage (290 MW)
2027-39	1.25% Energy Efficiency	1.00% Energy Efficiency	0.75% Energy Efficiency	0.5% Energy Efficiency	0.50% Energy Efficiency
2033-39	-	-	New Storage (50 MW)	New Solar (800 MW) New Wind (2,750 MW) New Storage (190 MW)	-
2024-39	Avg Annual Capacity Mkt Purchases (10 MW)	Avg Annual Capacity Mkt Purchases (12 MW)	Avg Annual Capacity Mkt Purchases (4 MW)	Avg Annual Capacity Mkt Purchases (203 MW)	Avg Annual Capacity Mkt Purchases (11 MW)

8.1.3.1 Reference Case

The Reference Case is considered to be the "most likely" case, built with commodity forecasts based on a consensus outlook from industry experts as described in Section 7.2 Reference Case Scenario.

The least cost Reference Case portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new 236.6 MW CT selected in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while the optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 137.5 MW during the period 2024-2039. Finally, 250 MW of solar is selected in the final three years of the forecast (2037-2039).

8.1.3.2 Status Quo

The BAU to 2039 status quo portfolio was designed, by definition, to provide a business as usual outlook through the forecast period. In this portfolio, each of the four Vectren-owned coal generation units are kept in operation to 2039, subject to various upgrades to keep them in compliance with existing environmental regulatory requirements. The Warrick 4 unit was given the option to extend for an additional three years of operation before exiting the joint agreement, but ultimately was not selected by the optimization routine for continuation based on purely economic considerations. This portfolio provides a useful, status quo benchmark for financial and operational performance to compare against all the other candidate portfolios. Vectren exits Warrick 4 joint operations with Alcoa. This 150 MWs is replaced with renewables. The optimized (least costs) BAU to 2039 portfolio includes 300 MW of wind resources selected in 2022, approximately 746

MW of solar selected in 2023 and 2024 and the selection in 2023 of paired "solar plus storage" resources (400 MW solar; 126 MW storage). Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while an additional block of EE (0.25%) is selected in the time period 2024-2026. This portfolio is capacity-rich, so no capacity market purchases are required during the period 2024-2039.

8.1.3.3 Four Scenario Based Portfolios

Four scenario-based portfolios (Low Regulatory, High Technology, 80% Reduction of CO_2 and High Regulatory) were developed to evaluate various regulatory constructs, economic and market conditions and technological progress. In general, the scenario-based portfolios move from low to high regulation, with intermediate levels of regulation characterized by the High Technology and 80% Reduction of CO_2 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. The following sections describe the qualitative and quantitative development of the scenario-based portfolios.

8.1.3.3.1 Low Regulatory

The Low Regulatory portfolio (optimized under high load conditions) includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new 279.3 MW CT is selected in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 1,000 MW of solar is selected beginning in 2026, while an additional 2,600 MW of wind is selected beginning in 2032. Approximately 1.00% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional block (0.25%) of energy efficiency is selected in the time period 2024-2026 and the optional demand response bin is selected in the time periods 2024-2026 and 2027-

2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 18.4 MW during the period 2024-2033. Because the Low Regulatory portfolio was significantly overbuilt relative to the Reference Case load outlook, this optimized portfolio was not selected for further analysis.

8.1.3.3.2 High Technology

The High Technology portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and two new 236.6 MW gas CT is selected in 2024 and 2025, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 50 MW of storage is selected in the final year of the forecast. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) with the exception of the third block of energy efficiency, which is not selected in the time period 2027-2039. The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. The only shortfall in capacity occurs in 2024 and is met through 70.9 MW of capacity market purchases. Because the optimized High Technology portfolio buildout had less reliance on the capacity market than the Reference Case portfolio, it offered a useful comparison of cost and performance. It was selected for further analysis and was eventually selected as the preferred portfolio.

8.1.3.3.3 80% CO_2 Reduction

The 80% Reduction of CO_2 by 2050 portfolio (least cost under reference case load conditions) includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 800 MW of solar is selected beginning in

2035, an additional 2,750 MW of wind is selected beginning in 2033 and an additional 266 MW of battery storage is selected beginning in 2036. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) with the exception of the third block of energy efficiency, which is not selected in the time period 2027-2039. The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. The only shortfall in capacity occurs in 2024 and is met through 70.9 MW of capacity market purchases. Because the optimized 80% Reduction of CO_2 by 2050 portfolio buildout was significantly overbuilt relative to the Reference Case load outlook, this optimized portfolio was not selected for further analysis.

8.1.3.3.4 High Regulatory

The least cost High Regulatory portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, approximately 152 MW of storage in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 1,810 MW of solar is selected beginning in 2025, an additional 3,300 MW of wind is selected beginning in 2025 and an additional 340 MW of battery storage (which is paired with wind) is selected beginning in 2025. Approximately 1.25% of energy efficiency blocks are selected in the first two time periods (near-term 2021-2023 and mid-term 2024-2026), while 0.50% of energy efficiency is selected in the time period 2027-2039. No optional demand response is selected. F B Culley 3 operations continue through the forecast period. The only shortfall in capacity occurs in 2024 and is met through 165.6 MW of capacity market purchases. Because the optimized High Regulatory portfolio buildout was significantly overbuilt relative to the Reference Case load outlook, this optimized portfolio was not selected for further analysis.

8.1.3.4 Bridges

The following portfolios were designed to serve as bridge portfolios, offering short-term and long-term transition pathways toward a fleet with greater renewable resources while utilizing existing resources.

8.1.3.4.1 Gas Conversion ABB1

This portfolio was designed to include the conversion of the older, less efficient unit at the A B Brown plant from a baseload coal-fired to natural gas peaking, which helps to preserve and repurpose much of the existing asset base. The unit would be converted for operation beginning in 2024 and expected to operate for 10 years before retirement. Conversions utilize some old equipment and require on-going capital investments to keep the units running. Since conversion of a unit offers less flexibility with slow start time (8-24 hrs.) and slow ramp rate (2MW/Min) it does not complement renewables well. The one conversion unit and the near-term (2021-2023) energy efficiency blocks are the only design parameters included in this candidate portfolio. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Gas Conversion ABB1 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), in addition to the conversion in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. One new 279.3 MW CT is selected in 2034 once the conversion unit is retired. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039). The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 133.3 MW during the period 2024-2033.

8.1.3.4.2 Gas Conversion ABB1 & ABB2

Similar to the Gas Conversion ABB1 portfolio, this portfolio was designed to include the conversion of both units at the A B Brown plant from baseload coal-fired units to natural gas peaking units. These conversions also help to preserve and repurpose much of the existing asset base at this facility. As described above, gas conversion units do not start or ramp quickly. Both units would be converted for operation beginning in 2024 and expected to operate for 10 years before retirement. The two conversion units and the near-term (2021-2023) energy efficiency blocks are the only design parameters included in this candidate portfolio. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Gas Conversion ABB1 & ABB2 portfolio retired F B Culley 2 and exited joint operations at Warrick 4. and includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), in addition to the two conversions in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. One new 279.3 MW CT is selected in 2034 once the conversion unit is retired. Approximately 0.50% of energy efficiency blocks are selected in the near-term (2021-2023), while 0.75% is selected in the mid-term (2024-2026) and long-term (2027-2039). The optional demand response bin is selected in the 2027-2039 time period. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 150.1 MW during the period 2034-2039.

8.1.3.4.3 Gas Conversion ABB1 + CCGT

This portfolio was designed to include conversion of one unit at the A B Brown plant from a baseload coal-fired unit to a natural gas peaking unit, which helps to preserve and repurpose much of the existing asset base at this facility. It retired A B Brown unit 2, F B Culley 2 and exited joint operations at Warrick 4. In addition, this portfolio includes a small CCGT unit with duct-firing capability (total 442.5 MW) in 2026. The conversion unit is be converted for operation beginning in 2024 and is expected to operate for 10 years before

retirement. The conversion and CCGT units are the only design parameters included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Gas Conversion ABB1 + CCGT portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and the conversion unit in 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. One new 432.6 MW combined cycle unit is designed to begin operations in 2026. Approximately 0.50% of energy efficiency blocks are selected in the near-term (2021-2023), while 0.75% is selected in the mid-term (2024-2026) and long-term (2027-2039). The optional demand response bin is selected in the 2024-2026 time period. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 16.4 MW during the period 2024-2039.

8.1.3.4.4 BAU 2029

The BAU 2029 portfolio was designed to bridge half of the study period (2019-2029) using existing baseload coal resources at A B Brown plant. Culley 2 (90 MW) is retired in 2023 and Vectren exits joint operations of Warrick 4 (150 MW) in 2023. The two coal units at A B Brown are extended through 2029 using existing FGD scrubber technology and retired by 2030. This portfolio strategy helps to preserve the existing asset base while providing a transition pathway to a generation fleet with greater renewable resources. The two coal unit extensions through 2029 is the only design parameters included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost BAU 2029 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new 236.6 MW gas

CT is selected in 2030. The coal unit F B Culley 2 and Warrick 4 are selected for retirement or exit of joint operations beginning in 2024. Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional 0.25% is selected in the time period 2024-2026 and 2027-2039. The optional demand response bin is selected in the time period 2027-2039. F B Culley 3 operations continue through the forecast period. Any shortfall in capacity is met through capacity market purchases, which average 162.4 MW during the period 2030-2039.

8.1.3.5 Diverse

The following portfolios were designed to serve as portfolios that offer a diverse mix of baseload, peaking and intermittent technologies as well as a diversity of fuel sources including coal, natural gas and renewables.

8.1.3.5.1 Small CCGT with Renewables and Coal

The Small CCGT with Renewables and Coal portfolio was designed to provide a diversified mix of generation and fuel technologies, including a small-sized CCGT with duct-firing capability (total 442.5 MW). This portfolio strategy provides a transition pathway to a generation fleet, while maintaining and adding a diverse fuel mix of baseload generation technology. This portfolio retired A B Brown units 1 and 2, F B Culley 2 and exited joint operations at Warrick 4. The CCGT unit and the near-term (2021-2023), keeping Culley 3, and the selection of renewables, storage and DSM options were the only design parameter included in this candidate portfolio beyond near term EE. Also, additional CCGTs or CT's were not allowed to be selected. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Small CCGT with Renewables and Coal portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new small-sized CCGT with duct-firing capability (total 442.5 MW) that begins in

2025. Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional 0.25% is selected in the time periods 2024-2026 and 2027-2039. No optional demand response is selected. F B Culley 3 operations continue through the forecast period. There is a capacity shortfall in 2024 equal to 285.7 MW before the CCGT becomes operations, but thereafter any capacity shortfall is minimal and met through capacity market purchases, which average 21.5 MW during the period 2036-2039.

8.1.3.5.2 Mid CCGT with Renewables and Coal

The Mid CCGT with Renewables and Coal portfolio was designed to provide a diversified mix of generation and fuel technologies, including a medium-sized CCGT with duct-firing capability (total 510.7 MW). This portfolio strategy provides a transition pathway to a generation fleet with greater renewable resources while maintaining and adding a diverse mix of fuels and a diverse mix of baseload, peaking and intermittent generation technologies. This portfolio retired A B Brown units 1 and 2, F B Culley 2 and exited joint operations of Warrick 4. The CCGT unit, keeping Culley 3 and the selection of renewables and storage were the only design parameter included in this candidate portfolio beyond near term EE. Also, additional CCGTs or CT's were not allowed to be selected. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Mid CCGT with Renewables and Coal portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and one new medium-sized CCGT with duct-firing capability (total 510.7 MW) that begins in 2025. Approximately 0.50% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039), an additional 0.25% is selected in the time period 2024-2026. No optional demand response is selected. F B Culley 3 operations continue through the forecast period. There is a capacity shortfall in 2024 equal to 285.7 MW before the CCGT becomes operational, but thereafter any capacity shortfall is minimal and met through capacity market purchases,

which occur only in 2039 and equal 3 MW. Because this portfolio did not produce a meaningful distinction with the optimized least cost Small CCGT with Renewables and Coal portfolio other than increased cost, with limited performance benefits, this portfolio was not selected for further analysis.

8.1.3.6 Renewables Focused

The following portfolios were designed to include a primary focus on renewable and battery storage resources, using three strategies: (1) closing all fossil by 2030 and backfilling only with renewables and battery storage resource, (2) closing all coal units by 2034 and backfilling with flexible units (CTs) and renewables and (3) optimizing a renewables-focused portfolio using a very high CO_2 price (modeled after the HB 763 bill introduced before the U.S. Congress) that begins in 2022 at $15 and increases by $10 per short ton each year, reaching ~$200 by 2039. The third portfolio strategy (HB 763) was included for initial analysis based on direct feedback from stakeholders through the public stakeholder process.

8.1.3.6.1 Close All Fossil by 2030

The close All Fossil by 2030 portfolio was designed to transition Vectren's generation fleet to 100% renewables and battery storage beginning in 2030, which requires closing all coal and natural gas peaking units by the end of 2029. This portfolio strategy provides a rapid transition pathway to a generation fleet with 100% renewable and battery storage resources. The requirement that all fossil retire by the end of 2029 was the only design parameter included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Close All Fossil by 2030 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage) and approximately 152 MW of battery storage are selected in 2023 and 2024, all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. F B Culley 3 and the two

gas peaking units at A B Brown continue operating through 2029 before retiring in 2030. An additional 1,150 MW of solar resources are selected beginning in 2027, while an additional 360 MW of battery storage are selected beginning in 2027. Approximately 1.00% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while the optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. Any shortfall in capacity is met through capacity market purchases, which average 169.7 MW during the period 2024-2039.

8.1.3.6.2 Renewables + Flexible Gas (CTs), Close Coal by 2034

The Renewables + Flexible Gas (CTs), Close Coal by 2034 portfolio was designed to transition Vectren's generation fleet to renewables and battery storage while also maintaining the flexibility afforded by gas CTs. This portfolio strategy provides a transition pathway to a generation fleet focused on renewable and battery storage resources while maintaining the resource adequacy provided by flexible gas CTs. The requirement that all coal units retire by the end of 2033 was the only design parameter included in this candidate portfolio beyond near term EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost Renewables + Flexible Gas (CTs), Close Coal by 2034 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 600 MW of solar resources are selected beginning in 2034. F B Culley 3 operations continue through 2033 before retiring in 2034. Approximately 0.75% of energy efficiency blocks are selected in each of the three time periods (near-term 2021-2023, mid-term 2024-2026 and long-term 2027-2039) while the optional demand response bin is selected in the time periods 2024-2026 and 2027-2039. Any shortfall in capacity is met through capacity market purchases, which average 134.7 MW during the period 2024-2039.

8.1.3.6.3 HB 763

The HB 763 portfolio was designed to incentivize a rapid transition to renewables and battery storage through a very high CO_2 tax (modeled after the HB 763 bill introduced before the U.S. Congress) that begins in 2022 at $15 and increases by $10 per short ton each year, reaching $200 by 2039. This portfolio strategy provides a rapid and aggressive transition pathway to a generation fleet focused on renewable and battery storage resources. The CO_2 price and was the only design parameter included in this candidate portfolio beyond EE. All other resources are selected as part of the least-cost optimization routine in Aurora.

The least cost HB 763 portfolio includes 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024 and the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage), all of which replace A B Brown units 1 and 2, F B Culley 2 and Warrick 4. An additional 1,650 MW of solar resources are selected beginning in 2025 and an additional 3,150 MW of wind resources are selected beginning in 2025. F B Culley 3 operations as well as the two gas peaking units at A B Brown plant continue through the forecast period. Approximately 1.25% of energy efficiency blocks are selected in the near-term (2021-2023), approximately 1.50% of energy efficiency blocks are selected in the medium-term (2024-2026) and approximately 1.00% of energy efficiency blocks are selected in the long-term (2027-2039). No optional demand response is selected. A one-year shortfall in capacity in 2024 is met through capacity market purchases, which equal 164.2 MW. Because the optimized HB 763 portfolio buildout was significantly overbuilt relative to the Reference Case load outlook, because this portfolio was the only portfolio that showed significant amounts of wind and solar curtailments (reaching as high as 11.8% annually and 21.4% annually, respectively) and because this portfolio had very high annual net energy sales, this optimized portfolio was not selected for further analysis.

8.2 EVALUATION OF PORTFOLIO PERFORMANCE

A total of 15 portfolios were developed in this IRP process, as described above. After an initial process in which a least cost portfolio was selected, 10 of the portfolios were selected as candidate portfolios for further analysis.

Five were screened out. These included three scenario-based portfolios (80% Reduction of CO_2 by 2050, High Regulatory and Low Regulatory) and two additional portfolios optimized around a key feature (Diverse Medium CCGT and HB 763). The scenario-based portfolios were optimized using the long-term capacity expansion module of Aurora within the wide-ranging market inputs described in Section 7, then simulated in the chronological hourly dispatch module of Aurora. However, each of three scenario-based portfolios were shown to be heavily reliant on energy market sales to reduce total portfolio costs (43.3%, 229.1% and 62.9% higher than the Reference Case, respectively, for the 80% Reduction by 2050, High Regulatory and Low Regulatory portfolios). In addition, around-the-clock (ATC) market clearing prices were as much as 77.3% higher than the Reference Case (specifically in the High Regulatory portfolio). Similarly, the Diverse Medium CCGT portfolio produced comparable results to the Diverse Small CCGT portfolio but at additional cost with little to no additional benefit. The HB 763 portfolio new unit capital costs were 382% higher than the Reference Case, which sold $5.3 billion in energy market sales in a market with average ATC power prices 55% higher than the Reference Case. In effect, the very high energy market sales in the High Regulatory and HB 763 would create a merchant utility, while the other portfolios were not expected to offer additional insights beyond the 10 candidate portfolios shown in the Balanced Scorecard. Furthermore, the HB 763 portfolio showed relatively high levels of renewable energy curtailments that were not seen in any other portfolio in the deterministic modeling (and very rarely in the subsequent stochastic modeling, for those candidate portfolios that underwent risk analysis). For these reasons, these five scenarios were not selected for further analysis in the stochastic framework.

Each of the remaining candidate portfolios was then subjected to two different forms of a 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 be performed. In the Scenario Based risk analysis, the remaining ten candidate portfolios that were selected for further analysis were each modeled under each of the four scenarios with their respective market inputs. The following provides a summary of the results of this scenario risk analysis. The results of the deterministic scenario-based Risk Analysis are shown in Figures 8-2 – 8.5 below

Figure 8-2 – Portfolio NPVRR (million $)

	Scenarios				
	Reference	**Low Regulation**	**High Technology**	**80% Reduction of CO_2 by 2050**	**High Regulation**
Reference Case	100.0%	100.0%	100.0%	100.0%	100.0%
Business as Usual to 2039	119.7%	101.2%	120.7%	117.1%	112.5%
Business as Usual to 2029	108.0%	100.9%	108.5%	106.4%	104.8%
ABB1 Conversion + CCGT	112.6%	112.6%	111.5%	111.2%	107.4%
ABB1 Conversion	103.9%	104.5%	104.5%	103.9%	102.0%
ABB1 + ABB2 Conversions	110.0%	110.0%	110.1%	109.9%	105.5%
Diverse Small CCGT	105.3%	105.3%	104.2%	103.5%	102.7%
Renewables + Flexible Gas	98.4%	101.4%	98.2%	98.1%	97.7%
All Renewables by 2030	101.4%	108.2%	105.0%	100.5%	94.3%
High Technology	102.3%	102.6%	101.3%	102.1%	102.2%

Figure 8-3 – Portfolio CO2 Emissions Reductions by 2039 from 2019 Levels (thousand Tons)

	Scenarios				
	Reference	Low Regulation	High Technology	80% Reduction of CO_2 by 2050	High Regulation
Reference Case	78.2%	52.0%	87.9%	77.3%	76.4%
Business as Usual to 2039	60.3%	-22.5%	72.6%	54.3%	49.2%
Business as Usual to 2029	74.6%	53.6%	85.9%	74.0%	73.4%
ABB1 Conversion + CCGT	61.5%	40.0%	69.6%	61.8%	62.7%
ABB1 Conversion	74.0%	53.5%	85.6%	73.5%	72.9%
ABB1 + ABB2 Conversions	74.1%	53.5%	85.5%	73.5%	73.0%
Diverse Small CCGT	61.8%	39.8%	69.7%	61.9%	62.7%
Renewables + Flexible Gas	95.2%	90.2%	95.7%	94.9%	91.5%
All Renewables by 2030	95.8%	95.8%	96.0%	95.8%	95.8%
High Technology	77.8%	51.9%	88.2%	77.1%	76.1%

Figure 8-4 – Portfolio Average Market Purchase Amount (thousand MWh) from 2019-2039

	Scenarios				
	Reference	Low Regulation	High Technology	80% Reduction of CO_2 by 2050	High Regulation
Reference Case	100.0%	100.0%	100.0%	100.0%	100.0%
Business as Usual to 2039	79.6%	58.1%	97.7%	71.3%	17.1%
Business as Usual to 2029	84.1%	74.5%	90.1%	78.8%	73.5%
ABB1 Conversion + CCGT	38.9%	30.1%	46.0%	42.0%	38.7%
ABB1 Conversion	93.7%	90.9%	103.7%	82.6%	106.1%
ABB1 + ABB2 Conversions	93.2%	89.2%	101.2%	78.1%	104.2%
Diverse Small CCGT	36.2%	26.5%	42.2%	42.2%	35.7%
Renewables + Flexible Gas	108.5%	125.8%	98.9%	106.4%	139.7%
All Renewables by 2030	124.5%	166.1%	134.6%	117.9%	186.1%
High Technology	101.6%	94.0%	89.8%	102.1%	100.9%

Figure 8-5 – Portfolio Average Market Sale Amount (thousand MWh) from 2019-2039

	Scenarios				
	Reference	Low Regulation	High Technology	80% Reduction of CO_2 by 2050	High Regulation
Reference Case	100.0%	100.0%	100.0%	100.0%	100.0%
Business as Usual to 2039	141.9%	170.4%	114.9%	170.5%	222.1%
Business as Usual to 2029	129.8%	138.1%	121.3%	139.5%	140.3%
ABB1 Conversion + CCGT	160.4%	161.3%	139.4%	182.1%	136.0%
ABB1 Conversion	104.2%	102.2%	94.2%	113.2%	98.0%
ABB1 + ABB2 Conversions	107.6%	108.5%	99.9%	130.7%	102.0%
Diverse Small CCGT	160.2%	159.7%	139.1%	170.3%	138.9%
Renewables + Flexible Gas	104.7%	99.8%	108.2%	119.0%	97.3%
All Renewables by 2030	128.4%	116.3%	107.4%	143.9%	107.9%
High Technology	96.3%	99.0%	113.8%	94.0%	96.4%

Four portfolios performed very well across all the alternative scenarios and relative to the remaining six candidate portfolios in terms of low cost, low energy sales and purchases and greater CO_2 emissions reductions. These four portfolios included the Reference Case Renewables + Flexible Gas, All Renewables by 2030 and High Technology portfolios. Each of these portfolios ranked in the top four of 10 portfolios in terms of lowest cost, lowest energy purchases and greatest CO_2 emissions reductions. Similarly, three of these same four portfolios ranked in the top four of 10 portfolios in terms of lowest energy sales (the All Renewables by 2030 portfolio ranked 6th). Accordingly, these four portfolios performed well consistently across the metrics in the Balanced Scorecard[42] and were put forward as final candidates for consideration as the preferred portfolio.

By contrast, the remaining six of 10 portfolios performed relatively less well across these key metrics of portfolio cost, energy sales and purchases and CO_2 emissions reductions. In terms of cost, the BAU to 2039, ABB1 Conversion + CCGT, ABB1 + ABB2 Conversions and BAU to 2029 portfolios were the worst performers, with the notable exception of the two BAU portfolios under Low Regulatory scenario conditions (i.e., no CO_2 price). In terms

[42] Note: The scenario-based risk analysis measured CO_2 emissions reductions rather than CO_2-equivalent emissions reductions.

of CO_2 emissions reductions, the BAU to 2039, ABB1 Conversion + CCGT, Diverse Small CCGT and ABB1 + ABB2 Conversions portfolios showed the worst performance due to increased emissions from coal, CCGT, or coal-to-gas conversion unit operations. Finally, the BAU to 2039, ABB1 Conversion + CCGT, Diverse Small CCGT and ABB1 + ABB2 Conversions portfolios demonstrated the greatest exposure to market risk in terms of energy sales and purchases. The remaining two portfolios with one or both conversion of the A B Brown coal units performed relatively neither well nor poorly in each of these metrics. While the scenario based risk analysis was not the determinative factor for excluding portfolios or promoting them to final consideration, these results did help to inform the final decision-making process. In the end, all but the Reference Case Renewables + Flexible Gas, All Renewables by 2030 and High Technology portfolios were eliminated from final consideration.

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 describe these sensitivities and the conclusions drawn from this analysis, as well as any impact on the candidate portfolios.

The All-Source RFP resulted in a number of solar, wind and battery storage resources that were included as near-term resources in the optimization module of the Aurora model. A sensitivity was performed in which solar costs were increased by 30% to determine if this would impact their selection in 2022-2024, the timeframe during which they were offered and allowed to be selected in the model. The sensitivity showed that even with an increase of 30% in cost, the portfolio cost increased by 3.99% but the offerings remained below the market-clearing on-peak locational marginal price for Indiana and thus continued to be selected by the model as beneficial low-cost resources.

A sensitivity was conducted on the near-term (2021-2023) selectable energy efficiency blocks. The optimization module in the Aurora model selected between 0.50% and 1.50%

energy efficiency, based on the modeling inputs and the scenario being optimized. A sensitivity analysis was performed to compare 1.25% of energy efficiency to the 0.75% energy efficiency selected in the Reference Case. The sensitivity showed that increasing the near-term energy efficiency to 1.25% from 0.75% only increased the 20-year portfolio cost (NPVRR) by 0.15%.

MISO is considering moving to a seasonal planning requirement. Accordingly, a sensitivity was conducted to determine the implications to the Reference Case portfolio of building to a summer peak vs. a winter peak and the resulting impact this would have on seasonal planning reserve margin requirements. Modeling a dynamic seasonal planning reserve margin requirement proved to be challenging and ultimately was not pursued, so the sensitivity focused on comparing a summer peak construct to a winter peak construct. Summer peak load is higher than winter peak load, but this difference in peak load is partially offset by a difference in seasonal unit capacity rating. The optimization routine in the Aurora model consistently selected for the maximum amount of solar available in the early years. However, the analysis showed that a constraint was necessary to prevent an overbuild of solar in this early timeframe. This is because the lower peak capacity accreditation for solar during the winter season meant that the winter peak demand was not met with solar that exceeded 1,150 MW. Accordingly, this required a limitation on the availability of solar to this level. The amount of solar in the early years was also limited by practical considerations around logistics and operational feasibility.

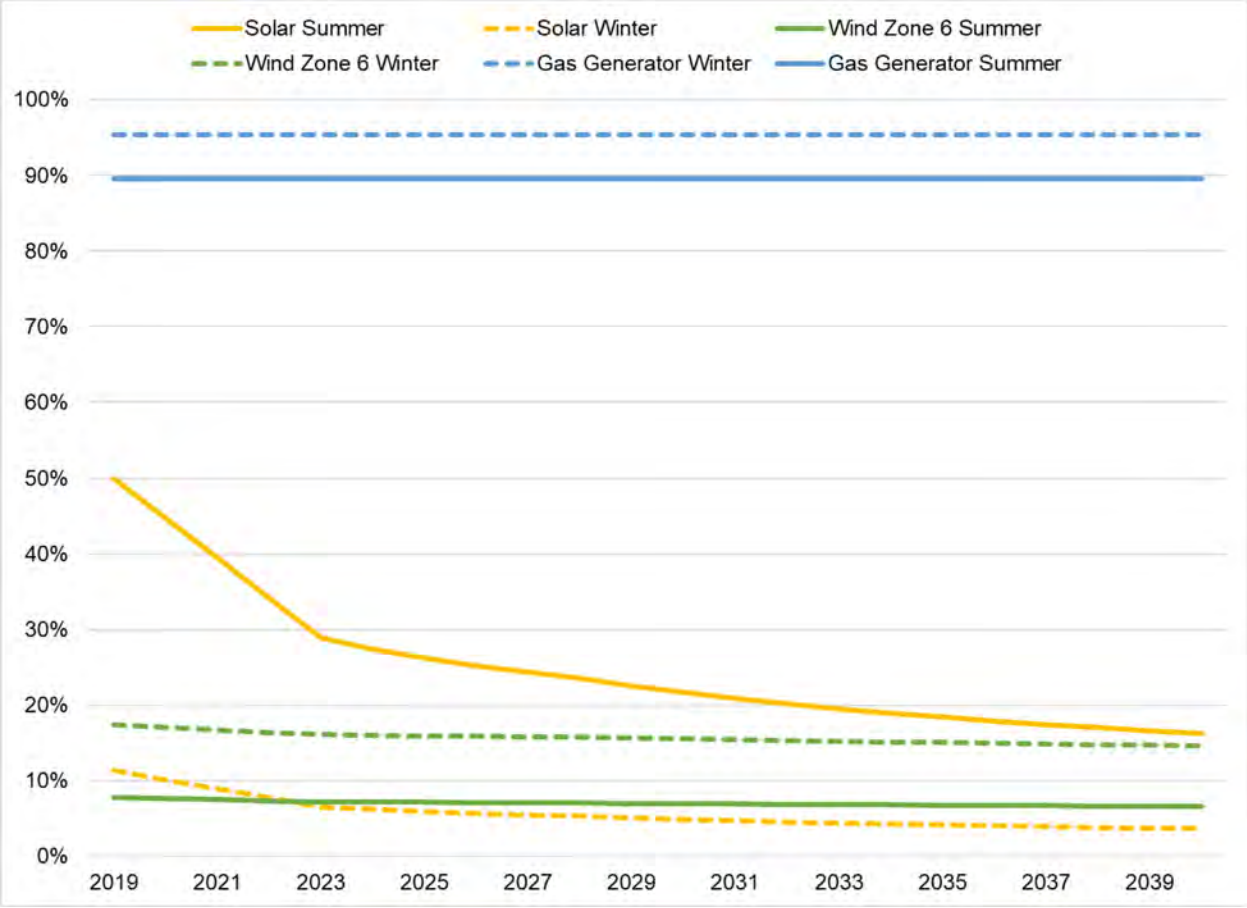
For this sensitivity, Vectren evaluated portfolios utilizing a reasonable summer and winter capacity accreditation construct as part of this IRP as a means of preparing for this implementation. All portfolios were required to meet both summer and winter peaks utilizing winter and summer accreditation. These forecasts were determined using MISO's ELCC accreditation formulas and MISO MTEP models for estimating renewable penetration levels. Applying similar methodology to MISO's current accreditation calculations, seasonal resource generation dispatching capabilities were accounted for. While using similar methodology to MISO's current solar would result in a 0% summer

accreditation, Vectren utilized a conservative assumption based on Stakeholder feedback of 11% UCAP accreditation (year 1). 11% was derived by providing some benefit to output at 9 am, which is one of the three non-consecutive highest winter load hours.

Figure 8-6 - Year 1 Seasonal Accreditation

Seasonal Capacity Accreditation	Year 1 (2019)	
	Summer	Winter
Solar	50%	11%
Wind MISO Zone 6	8%	17%
Gas Generator	~90%	~95%

Figure 8-7 - Seasonal UCAP Accreditation Forecast



The sensitivity demonstrated that Vectren should continue to plan for meeting its summer peak as the greater of the two seasonal constraints. When planning for and building to a winter peak, the Vectren system is built to meet the winter peak in all hours but is overbuilt to meet the summer peak in all hours. Based on this sensitivity analysis, each portfolio was designed and built to meet summer peak load and resulting planning reserve margin requirements.

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 all of that 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 Vectren 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 Vectren 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 8-8 - IRP Portfolio Balanced Scorecard Color-Coded Comparison (NPVRR in millions of dollars)

	Stochastic Mean 20-Year NPVRR	95th Percentile Value of NPVRR	% Reduction of CO2e (2019-2039)	Purchases as a % of Generation	Sales as a % of Generation	Purchases as a % of Peak Demand	Sales as a % of Peak Demand
Reference Case	$2,538	$2,921	58.1%	16.8%	26.8%	9.7%	1.2%
BAU to 2039	$2,914	$3,308	35.2%	12.0%	36.5%	0.1%	11.1%
Bridge BAU 2029	$2,691	$3,094	61.9%	15.2%	31.4%	7.1%	4.3%
Bridge ABB1 Conversion+CCGT	$2,875	$3,269	47.9%	6.6%	31.8%	1.3%	10.1%
Bridge ABB1 Conversion	$2,677	$3,048	61.5%	19.2%	26.4%	1.2%	9.3%
Bridge ABB1+ABB2 Conversion	$2,836	$3,215	61.5%	18.5%	27.6%	4.0%	5.6%
Diverse Small CCGT	$2,681	$3,072	47.9%	6.4%	31.1%	1.7%	3.7%
Renewables Peak Gas	$2,528	$2,927	77.4%	21.5%	27.7%	9.4%	1.2%
Renewables 2030	$2,614	$3,003	79.3%	26.1%	31.9%	11.9%	1.7%
High Technology	$2,592	$2,978	59.8%	16.7%	26.9%	0.4%	4.6%

A color-coded comparison (conducted automatically by the spreadsheet) of the balanced scorecard is shown above in Figure 8-8. Green indicates scoring well relative to its peers in a metric and red indicates scoring poorly relative to its peers. The color scheme is purely for illustrative purposes to show where differences between the best performing portfolio and the worst performing for that attribute is displayed.

The Mean of the Net Present Value is clearly one of the most important attributes, as it was the basis on which each of the portfolios were selected in the first place. Under both reference case conditions and also considering the mean of the distribution, the Renewables Peak Gas Portfolio, which retired Culley 3 early, was the lowest cost Portfolio but by less than half of one percent relative to the reference portfolio. Since Culley provides greater reliability, resilience and diversity to the portfolio and the flexibility to retire the plant early, Vectren did not consider this to be a significant difference.

The next two lowest cost portfolios were the Reference portfolio and the High Technology portfolios whose NPVRRs were within two percent of each other. Once again, Vectren

did not consider portfolios within two percentage points on both the mean of the distribution and the 95th percentile (representing cost uncertainty risk) to be significant enough to differentiate these two options on the basis of cost.

The Costs and 95th percentile of the Business As Usual Portfolio and two of the Bridge solutions (the Bridge ABB1 and ABB2 and the Bridge ABB1 plus CC) were well above 10 percent higher than the Reference Mean and 95th percentile solutions, so they were eliminated from further consideration on the basis of cost.

SECTION 9
IRP PREFERRED PORTFOLIO

9.1 PREFERRED PORTFOLIO RECOMMENDATION

Based upon several factors, Vectren's preferred portfolio is the High Technology Portfolio.

9.1.1 Description of the Preferred Portfolio

The new and existing supply and demand resources in the preferred portfolio (High Technology) include 300 MW of wind resources selected in 2022, approximately 746 MW of solar selected in 2023 and 2024, the selection in 2023 of paired solar+storage resources (400 MW solar; 126 MW storage[43]) and two new 236.6 MW CT units selected in 2024 and 2025, all of which replace the A B Brown 1 and 2, F B Culley 2 and Warrick 4 coal units when they retire or exit at the end of 2023. An additional 50 MW of storage is selected in the final year of the forecast for reserve margin purposes. Approximately 1.25% of energy efficiency blocks are included in the near-term time period (2021-2023), approximately 0.75% of energy efficiency blocks are selected in the mid-term (2024-2026) and approximately 0.50% of energy efficiency blocks are selected in the long-term (2027-2039). In addition, low Income energy efficiency is included in all periods. The optional demand response bin is selected in the time periods 2024-2026 and 2027-2039, while a Direct Load Control (DLC) program called Summer Cycler is transitioned to Wi-Fi thermostats over time. F B Culley 3 operations continue throughout the forecast period. The only shortfall in capacity occurs in 2024 and is met through 70.9 MW of capacity market purchases.

The preferred portfolio (High Technology) performs well across a range of metrics, both in absolute terms and relative to the other candidate portfolios. The preferred portfolio (High Technology) was within 2.5 percent of the lowest cost portfolio and ranked 2 out of 10 (second best) in the 95th percentile cost risk metric. It did not over-rely on either purchases or sales of energy or capacity.

[43] Modeled as 3-hour battery. Equates to a ~90MWs for 4-hours

Importantly it provides the flexibility and optionality to move quickly to a more renewable future as the reliability of the MISO system adapts to higher levels of renewables across the system. By having the option to retire Culley, Vectren can move when needed to a portfolio more like the Renewable + Flexible Gas portfolio.

Another distinguishing factor in this portfolio is the selection of two CTs. The two CT's provide the following benefits:

- They eliminate the reliance on for capacity in the near term at a time when MISO suggests that there could be shortages
- They provide the capability to convert to a combined cycle if needed for reliability in the future
- They are primarily used for peaking and fast ramping, which provides more room for renewables in the future
- They are relatively inexpensive to build and save customers ~$50M in design and construction costs by building two units at the same time vs. waiting to build the 2nd
- Maintains interconnection rights should units be built at the Brown site, shielding customers from future transmission upgrade costs

The High Technology portfolio provides a number of additional benefits to Vectren customers and other stakeholders, including that it:

- Is among the best performing portfolios across multiple measures on the balanced scorecard
- Is a low cost portfolio (within 2.5% of the lowest cost portfolio and 2.2% of the Reference Case (the latter of which is the more appropriate comparison due to the same assumption that F B Culley 3 is operational through the forecast period)
- Leads to a lower carbon future – Achieves almost 60 percent reduction in life cycle carbon emissions (CO_2e) during the period 2019-2039 and achieves a nearly 75%

reduction in CO_2 (base year 2005) by 2035 with the flexibility to achieve even more if needed

- Brings a significant volume of renewables into the portfolio beginning in 2022. Renewable resources and ongoing energy efficiency account for more than 72% of total installed capacity by 2024 (more than 42% in terms of UCAP)
- Provides dispatchable generation that enhances opportunities for economic development and wholesale sales without overexposure to market risk relative to other candidate portfolios, which lowers customer bills
- Provides fast ramping generation to help manage the intermittency of renewables, including extended periods of complete cloud cover that can reduce solar generation by up to 75%[44]
- Avoids reliance on a single fuel and provides a balanced and diversified mix of renewables, DSM, gas and coal.
- Provides the optionality of converting to a combined cycle unit in the future if market, regulatory, technological and/or economic conditions necessitate
- Reduces dependence on coal-fired generation in a prompt timeframe yet provides the flexibility to adapt to changes in technology in the future
- Takes advantage of tax incentives for new solar power plants and for new wind resources

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 Net Present Value of Revenue Requirements (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

[44] NASA, Cloud Cover and Solar Irradiation, (source: https://scool.larc.nasa.gov/lesson_plans/CloudCoverSolarRadiation.pdf) using the formula shown below:

$$P = 990\ (1\text{-}0.75F^3)\quad watts/m^2$$

where F is the fraction of sky cloud cover on a scale from 0.0 (0% no clouds) to 1.0 (100% complete coverage).

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 Vectren's weighted average cost of capital of 7.71% to arrive at the NPVRR. The lower the NPVRR is for a portfolio, the lower the rates can be in order 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 preferred portfolio (High Technology) was determined to be a cost portfolio across the 10 candidate portfolios, with a 20-year NPVRR of $2,592 million. This NPVRR is only 2.16% higher than the Reference Portfolio, a difference of less than $55 million over 20 years on a net present value basis. The preferred portfolio (High Technology) is 11% less expensive than the Business as Usual to 2039 portfolio (the most expensive portfolio in this objective category), which provides a savings of nearly $322 million over 20 years on a net present value basis.

9.1.3 Cost Uncertainty Risk Minimization

The Cost Uncertainty 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 Price 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 (High Technology) performed well in the Price Risk Minimization category. The 95th percentile of the 20-year NPVRR was determined to be $2,978 million, which is only 1.95% higher ($57 million) as compared to the Reference Portfolio 95th percentile of the 20-year NPVRR. For this same objective, the preferred portfolio (High Technology) was found to be $330 million less than the Business as Usual to 2039 portfolio, which is also the most expensive portfolio in this objective category. Accordingly, the preferred portfolio (High Technology) is shown to have a low level of price 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.

9.1.4 Environmental Emission Minimization

The Environmental Emission Minimization objective is determined from the stochastic analysis and is measured as the life cycle greenhouse gas emissions reductions during the study period of 2019-2039. Life cycle greenhouse gas emissions are also known as CO_2-equivalent or CO_2e emissions. The development of this measure is described in detail in Section 2.3.2.3 and takes into account the CO_2e emissions associated with the annual MWh of generation over 20 years from each technology type in the candidate portfolio. CO_2e emissions are also calculated for any energy imports from MISO, using a representative future capacity mix by resource that is associated with the 2033 Accelerated Fleet Change mix from MISO's MTEP 2019 document.

The preferred portfolio (High Technology) performed relatively well in the Environmental Risk Minimization objective, reducing annual CO_2e emissions by more than 4 million tons over the 2019-2039 study period (where 2019 CO_2e emissions are more than 6.7 million). This represents a nearly 60% decrease over 20 years and a larger decrease than is shown in the Reference Case, which is determined to have a 58% decrease. Relative to the other candidate portfolios, the preferred portfolio (High Technology) shows a CO_2e emissions reduction figure that is in the middle of the pack, with a smaller reduction than the renewables focused portfolios but a greater reduction than the Business as Usual to 2039 portfolio, which only reduces CO_2e emissions by 35% over the 20 year study period.

However, there is flexibility built into this portfolio to achieve further reductions if coal is no longer needed for reliability and resilience purposes and if the economics of renewables becomes even more compelling.

While not part of the balanced scorecard, the preferred portfolio (High Technology) was found to reduce (actual not life cycle) CO_2 emissions by 74.5% compared to the baseline year of 2005. This represents an annual reduction of nearly 7.2 million tons of CO_2 from the baseline of 9.6 million tons of CO_2. This figure is more than twice the reduction of CO_2 emissions that is shown in the Business as Usual to 2039 portfolio and slightly greater than the Reference Case CO_2 emissions reduction.

9.1.5 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 Vectren 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 Vectren 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 Vectren 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 Vectren 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 (High Technology) performed relatively well in terms of energy market risk minimization, averaging 16.7% energy purchases as a percentage of generation. This figure is in the middle of the 10 candidate portfolios, slightly less than the Reference Case (16.8%) and much less than the Renewables 2030 portfolio (26.1%) but

greater than the Diverse Small CCGT portfolio (6.4%). The preferred portfolio (High Technology) ranked third best in terms of energy sales with a figure of 26.9% as a percentage of generation, only slightly more than the best performing portfolio in this category (the Bridge ABB1 Conversion portfolio at 26.4%) and much less than the Business as Usual to 2039 portfolio at 36.5%. When looking at net energy sales, the preferred portfolio (High Technology) demonstrates a figure of 10.2%, which is within the threshold criteria of 15% that was discussed during a stakeholder meeting. The 15% level is based on a reasonable level of net sales that would not overexpose Vectren to energy market risks, in the estimation of Vectren's market consultants. Accordingly, the preferred portfolio (High Technology) was shown to have a reasonably minimal level of energy market risk, both in terms of its own measure and relative to the measures of other candidate portfolios.

The preferred portfolio (High Technology) performed relatively well in terms of capacity market risk minimization, demonstrating a figure of only 0.4% capacity market purchases as a percentage of peak load. This figure is the second lowest of the 10 candidate portfolios, only slightly more than the Business as Usual to 2039 portfolio with 0.1% capacity market purchases. The selection of two CT's reduces the need for significant levels of capacity purchases throughout the planning horizon, which is important since MISO is still evaluating the issues of reliability and resilience of the grid as renewables become a larger share of the region's portfolio. The preferred portfolio (High Technology) was determined to have capacity market sales of 4.6% as a percentage of peak load, which is in the middle of the 10 candidate portfolios and much less than the 11.1% capacity market sales in the Business as Usual to 2039 portfolio but greater than the Reference Case portfolio with 1.2% capacity market sales. Accordingly, the preferred portfolio (High Technology) was shown to have a reasonably minimal level of capacity market risk, both in terms of its own measure and relative to the measures of other candidate portfolios.

9.1.6 Other Considerations

9.1.6.1 Future Flexibility

The preferred portfolio (High Technology) was originally selected using a least-cost capacity expansion under the market conditions for the High Technology alternative scenario, but was then dispatched under the same Reference Case market conditions in the deterministic analysis and then evaluated using the same range of market conditions as all other candidate portfolios in the stochastic analysis.

These alternative market conditions for the optimization included lower CO_2 costs, higher load, lower fuel prices and lower renewable and EE costs, all relative to the Reference Case. Each of the market conditions are plausible alternatives to the most expected path in the Reference Case. For example, there is not yet a political consensus on whether and how to implement a national tax on carbon, which provides some justification for a lower CO_2 price relative to the Reference Case. The load growth from electric vehicles and the electrification of several sectors (buildings, industry, heavy transport) represent substantially more upside potential than the savings and downside potential that could come from demand side management and energy efficiency, which provides some justification for a higher load outlook. Coal markets experienced a downturn in 2020 due to COVID-19-induced demand reduction, from which (together with many other downward market pressures) it will be difficult to recover in the long-term. Gas prices have come down significantly in the last decade due to technology improvements and an expanding list of reserves from new discoveries, which could continue over the next two decades, while a more aggressive move to renewables could undercut demand for natural gas in the power sector, all of which would put increased downward pressure on gas prices. Finally, an aggressive expansion of renewables relative to the Reference Case could put downward pressure on capital costs, in much the same way that the broad deployment of personal computers led to lower prices due to economies of scale.

The preferred portfolio (High Technology) performed well across the various metrics in the balanced scorecard in both the Reference Case (expected) market conditions and (by

definition) the High Technology market conditions, which are only slightly less probable than the Reference Case market conditions (in the estimation of Vectren's market consultants). It also performed well relative to the other candidate portfolios when dispatched in the 80% Reduction by 2050, High Regulation and Low Regulation alternative market conditions. In all of the scenario-based alternative market conditions as well as the stochastic analysis with 200 iterations of varying market conditions, the preferred portfolio (High Technology) did not show any solar energy curtailments and only showed an expected average value of 0.02% wind energy curtailment in five years during the 2019-2039 study period. Thus, the preferred portfolio (High Technology) demonstrated the flexibility to adapt to a wide range of changing market conditions.

9.1.6.2 Uneconomic Asset Risk

One of the factors that Vectren considered was the potential for assets becoming uneconomic over the planning horizon. This was a concern raised by stakeholders about the 2016 IRP when Vectren recommended building a large combined cycle plant which benefited from a significant reliance on projected energy sales to support its economics. One of the concerns expressed was whether the plant could become uneconomic if renewables and storage were to achieve rapid cost declines such that the combined cycle dispatch would be adversely impacted and thus unable to cover its costs.

An analysis was performed to determine whether this was a significant risk with the mix of assets proposed. A metric was created to assess the risk. An asset was determined to be uneconomic during one of the iterations of the risk analysis if for three years in succession, revenues would not recover costs. The analysis performed determined that the assets most at risk were the assets that were selected to provide capacity to support the renewable resources, mainly the CT's and storage. The reason is that especially early in the planning horizon, capacity has often been priced below CONE. While MISO has indicated a concern that shortages could well occur in MISO over the next several years, this was not reflected in many of the iterations. Ultimately the value of this metric is questionable. Portfolios with plants with large energy revenues (coal and combined cycle)

performed better than combustion turbines, even though they require a larger capital spend than CTs.

If Vectren were to mitigate this conclusion it would rely heavily on purchases in the capacity market rather than build CT's and storage. Vectren did not believe this was appropriate in this uncertain environment and chose a path with CT's and storage rather than relying heavily on the capacity market.

9.1.6.3 Reliability

Reliability can be measured in different ways, but one common metric is whether the portfolio experiences any unserved energy. The preferred portfolio (High Technology) was dispatched in the Aurora 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 (High Technology) was not found to have any hours of unserved energy. Accordingly, although Reliability is not an explicit objective in the balanced scorecard, the preferred portfolio (High Technology) was found to provide reliable service in meeting Vectren's expected load requirements over the 20-year study period.

Two highly dispatchable combustion turbines (460 MW) support a high penetration of renewables, ensuring reliability and provide a hedge against both the energy and capacity markets. They help provide customers assurance of reliable service in many ways.

- Thermal resources are still needed to maintain reliable service in multiday periods of cloud cover and no wind
- Two CT's provide better support than one. Better coverage should a unit go down to provide a hedge against high energy prices and provide system support when issues arise

- Two CT's keeps existing interconnection rights, which shields customers from potential transmission upgrade costs in the future should Vectren have to re-enter the MISO Queue (a three-year process).
- Two CT's provide fast start (10 min) & more fast ramping capability (80 MW/minute vs 40 MW/minute) to help support for intermittent solar and allows for a smooth transition into a renewables future locally and regionally as the MISO system adapts to higher levels of renewables across the system
- Two CT's provide a high degree of flexibility in the future

9.1.6.4 Operational Flexibility

The preferred portfolio (High Technology) includes a significant amount of new variable energy resources (VER) (wind and solar) balanced by 176 MW of battery storage (50 MW of which enters late in the forecast) and two 236.6 MW natural gas peaking units. The battery storage and 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 CT's and battery storage 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 (High Technology) (approximately 1,500 MW) together with the fast-ramping capabilities of the CT's and battery storage, this portfolio is expected to meet all operational flexibility requirements.

Natural gas peaking combustion turbines (CT) 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). CT's 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. CT's can also be black started, offering an additional degree of increased resiliency and operational flexibility.

Given the high volume of intermittent renewable generation in the preferred portfolio Vectren feels it's critical to have an adequate amount of dispatchable generation to meet its obligation to ensure reliable service is provided to Vectren customers throughout the different seasons of the year as well as all 24 hours of the day. Vectren'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.

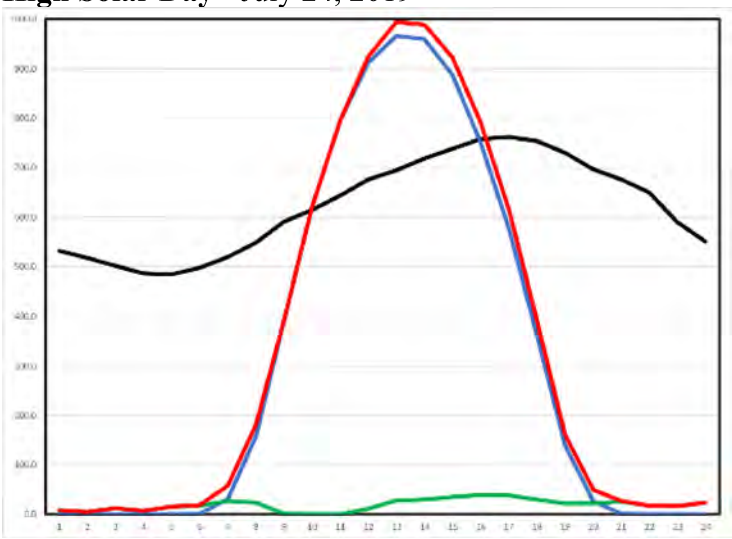
9.1.6.4.1 Vectren Seasonal and Daily Experience with Solar and Wind Production

The figures 9.1-9.4[45] below are actual seasonal days during 2019 and 2020 that show hour by hour customer demand and how 1,000 MW's of solar capacity and 380 MW's of wind capacity would have met customer demand if the solar and wind capacity factors were the same as what was realized from Vectren's current solar fields and wind purchase power agreements. High, typical and low solar production days were chosen for each season to show the large variation in levels that can be experienced daily during each season. Also, note the large drop off in production in the evening hours after the sun goes down. The additional energy required to serve Vectren customer demand would need to be purchased from the market or supplied by Vectren owned dispatchable generation sources. Local generation ensures more reliable energy and capacity with less risk of additional congestion charges associated with importing energy.

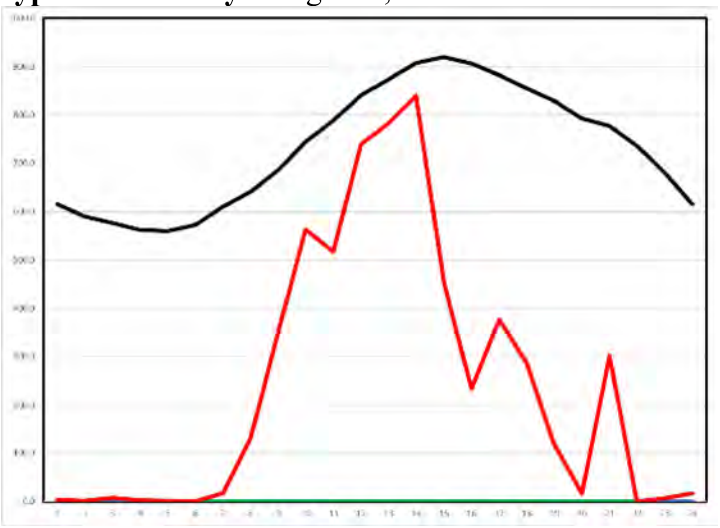
[45] **Black – System Load, Green – Wind, Blue – Solar, Red – Wind + Solar Used 1000 MW solar (scaled up from existing solar), 380MW wind (scaled up from existing 80MW). All data in 1-hour average increments, charts range from 0 to 1,000 MW except on high solar days in December (1,200MW) and March (1,400MW)**

Figure 9-1 - Summer Production and Vectren Demand:

High Solar Day - July 24, 2019



Typical Solar Day - August 9, 2019



Low Solar Day - July 15, 2019

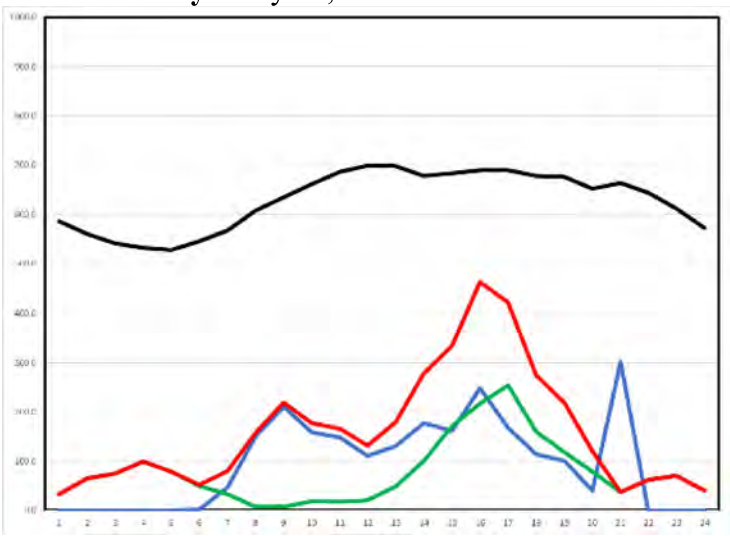
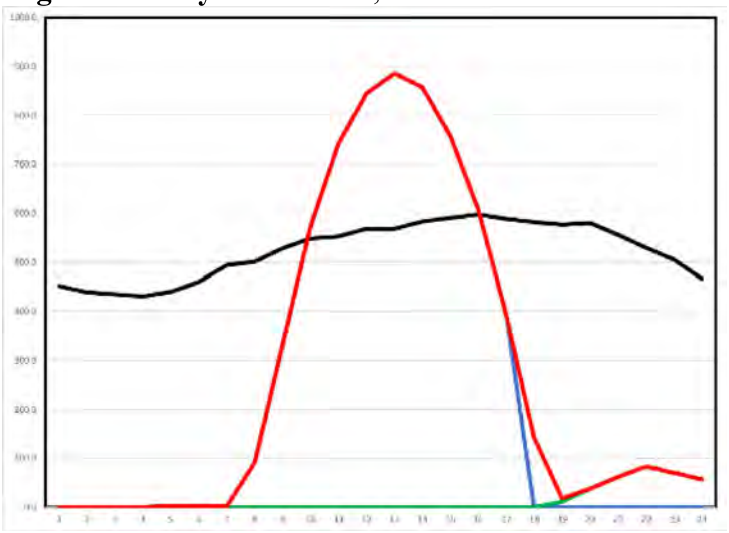
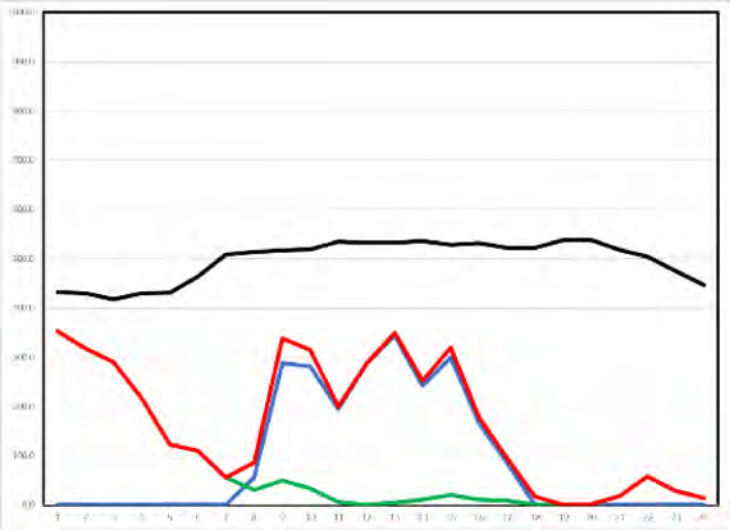


Figure 9-2 – Fall Production and Vectren Demand:

High Solar Day – October 8, 2019



Typical Solar Day – October 18, 2019



Low Solar Day – October 25, 2019

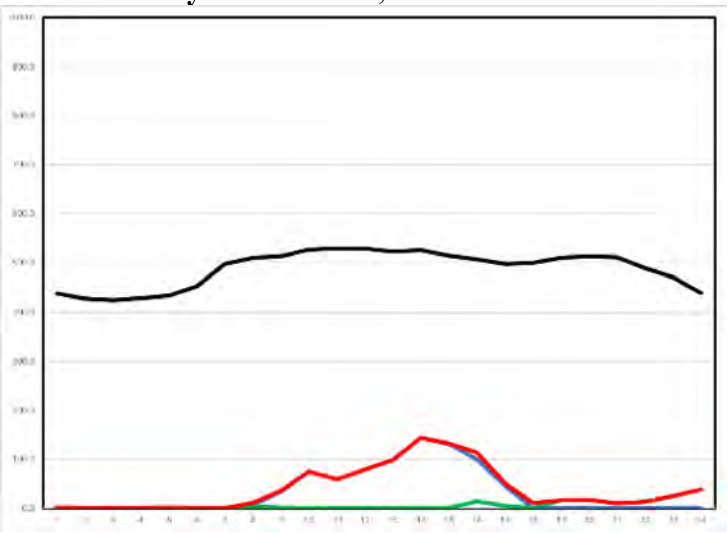
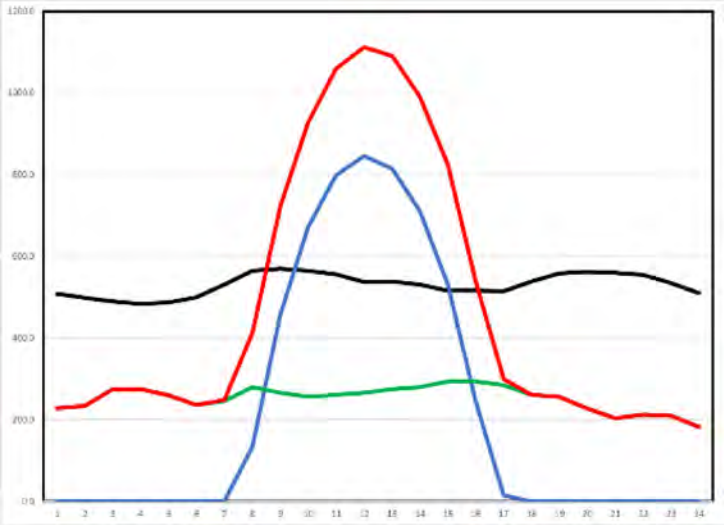
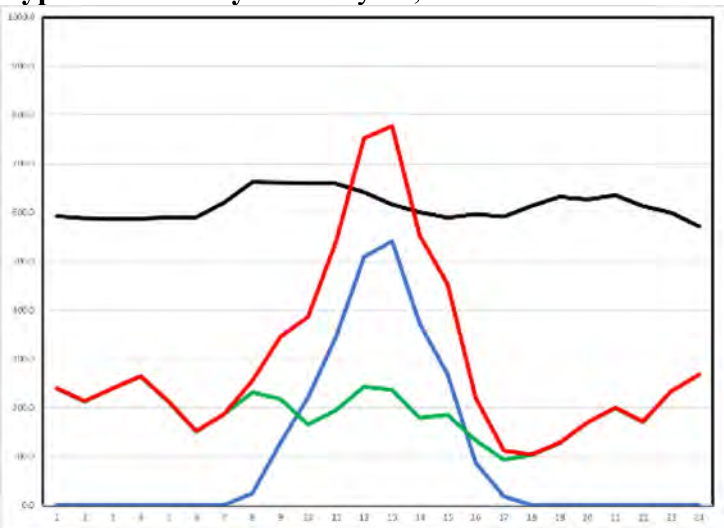


Figure 9-3 - Winter Production and Vectren Demand:

High Solar Day - December 4, 2019



Typical Solar Day - January 22, 2020



Low Solar Day - December 16, 2019

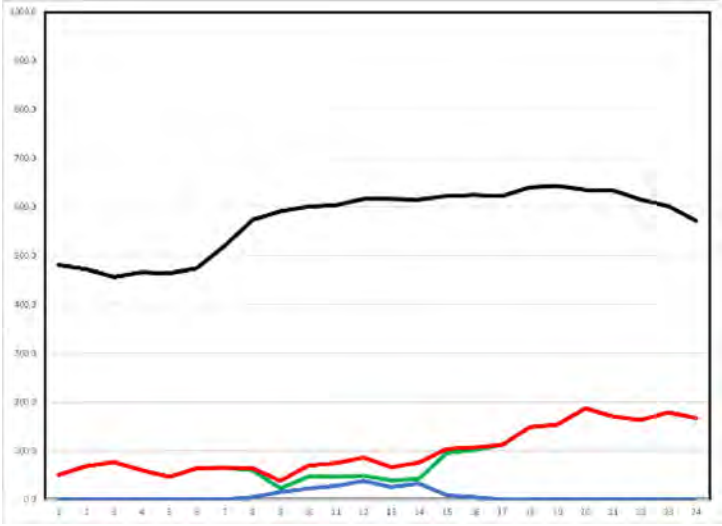
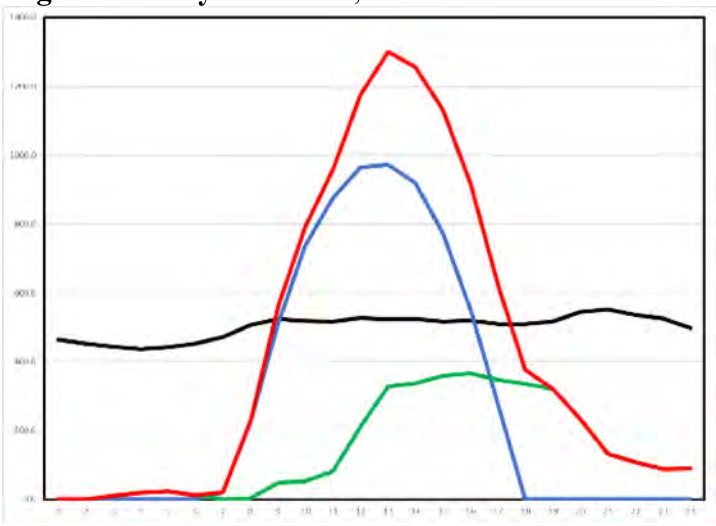
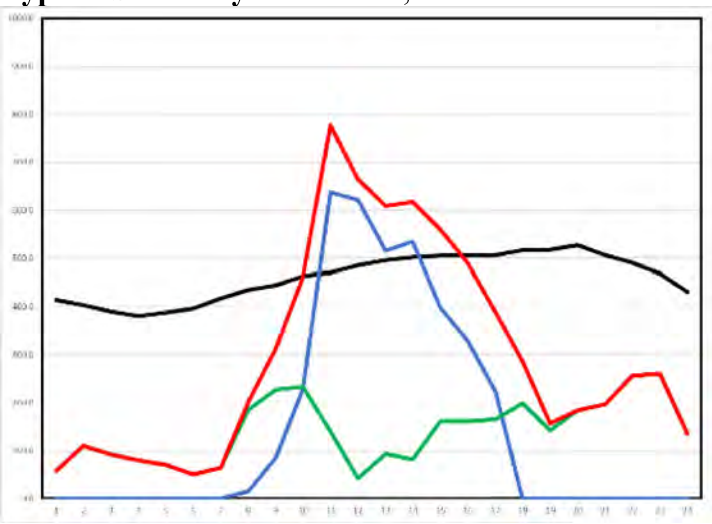


Figure 9-4 - Spring Production and Vectren Demand:

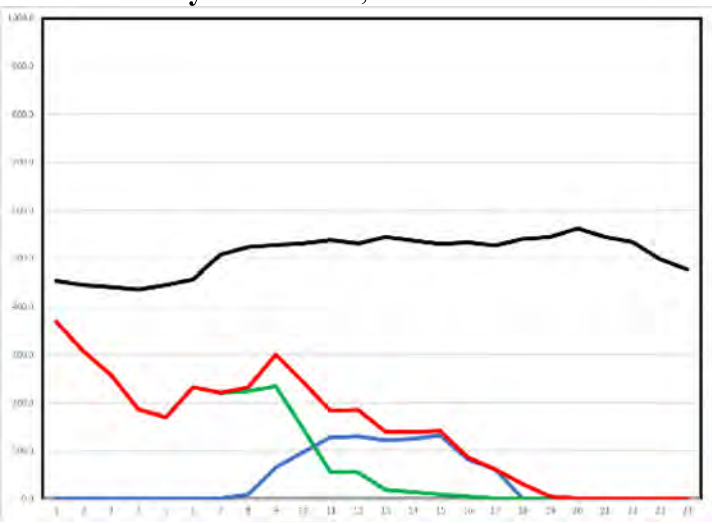
High Solar Day – March 3, 2020



Typical Solar Day – March 27, 2020



Low Solar Day – March 10, 2020



9.1.6.4.2 Vectren Experience with Solar Hourly and Daily Intermittency

The Figures above (9.1-9.4) represent an average hourly output or artificial smoothing of production across each hour of the day. There are days when there are large fluctuations in output over short periods of time due to changes in cloud cover or periodic gusts of wind. The figures below (9.5 and 9.6) show actual variation in output over a twenty-four-hour period and a one-hour period. These rapid fluctuations in output while working to

meet constantly changing customer demand require a robust transmission and distribution system to import large amount of power quickly as well as dispatchable resources that can ramp output up and down quickly. It should be noted that as other utilities retire coal resources and install more intermittent generation it will become more important to have locally placed fast reacting dispatchable resources to ensure reliable service is delivered to industrial, commercial and residential customers.

Figure 9-5 – 24 Hour Solar Chart

Sept. 2, 2019 - 12:00 to 13:00

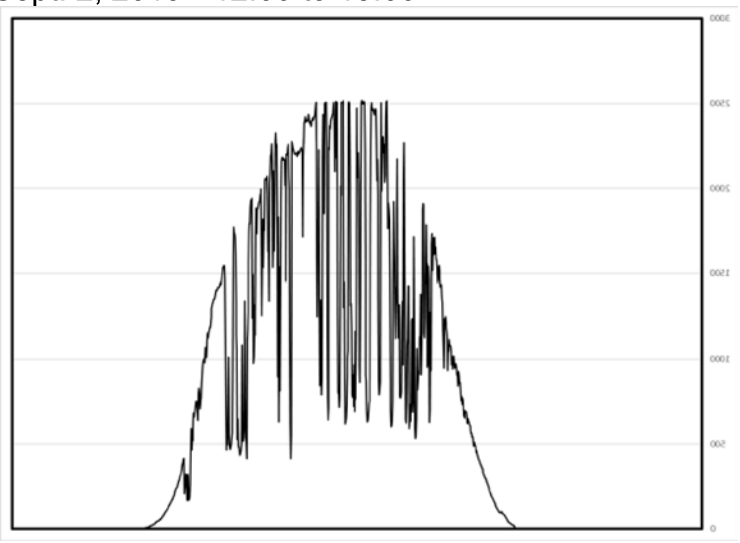
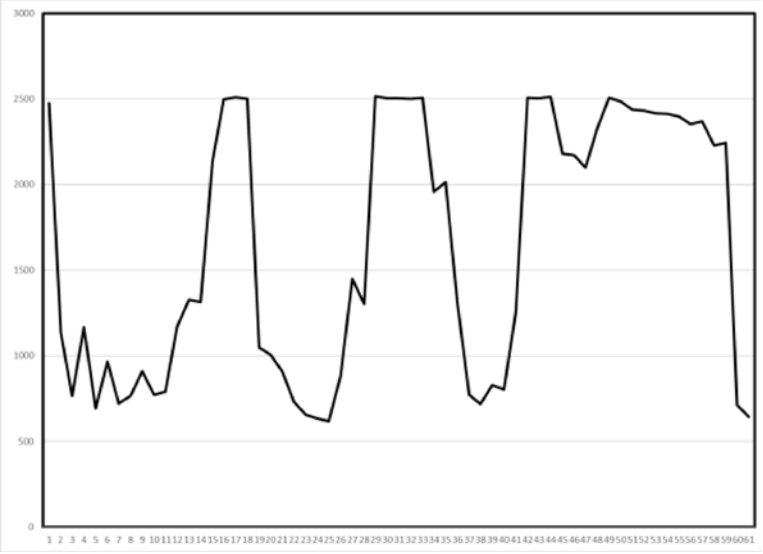


Figure 9-6 – 1-Hour Solar Production – September 2, 2019



Figures 9.5-9.6 aren't representative of every day throughout the year as there will be days when solar and wind production are more consistent; however, Vectren has an obligation to ensure customer demand is met by supplying reliable energy throughout every minute of every day of the year. Local fast start and fast reacting dispatchable resources will still be required to meet customer demand on days like Vectren experienced on September 2, 2019 as well as the evening hours after the sun goes down. Battery storage systems can meet a portion of this need; however, they are limited by discharge times as well as charge/discharge cycles, whereas CT's provide more long duration support.

Each unit will have the ability to start and be synchronized to the grid producing energy in approximately 10 minutes. This is important when relying on a large portfolio of renewable capacity. The CT's may be required to start and provide reliable energy for customers several times throughout the year when renewable energy is operating at reduced capacity due to cloud cover or a lack of wind. It's likely there may be times when the CT's are started and stopped more than one time daily.

Once placed in service, the quick ramping ability of a CT, at approximately 40MW/minute, will help meet customer needs when demand changes or renewable energy supplies quickly dip then return as cloud cover rolls over various solar arrays and wind fluctuates in areas where wind farms are built. Having two new CT's will provide the ability to ramp or adjust output by up to 80MW/minute to help supplement the import capability of the grid. In addition, having two CT's will provide flexibility as only one or both can be started as needed. Due to environmental restrictions, each CT will have a minimum output of approximately 80MW's. With one in service, the output can range from 80-220MW's. With both units in service, the output can range from 160-440MW's providing the operational flexibility to meet the needs of customers.

Of the gas fired generation options explored, the CT's were chosen due to the balance of low capital cost, efficiency and operational flexibility. Given the quantitative objectives in the balanced scorecard that includes; (a) minimizing the cost to the customer, (b) reducing emissions and (c) not relying heavily on the energy or capacity market as well as the qualitative objective such as diversity and properly supporting a large portfolio of renewable resources the CT's were chosen as an important resource in the preferred portfolio.

Lastly, the preferred portfolio with two CT's provides future flexibility to increase capacity and provide lower cost energy to Vectren customers by adding a steam cycle to one or both CT's. A steam cycle could be placed on one or both CT's to create a Combined Cycle Gas Turbine (CCGT) to capture waste heat to be turned into energy. This would lower the cost/MWh by increasing the efficiency of a CT by 30-35%. This could be accomplished if the need arises as a result of load growth due to new industrial customers, if it were determined in a future IRP that Culley Unit 3 should be retired, or the need for more low cost energy arises due to higher than expected market energy prices.

9.1.6.5 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 (High Technology) is reasonably diverse and well-balanced in terms of resources, with a mix of natural gas CTs, solar and wind resources, battery storage resources and a baseload coal unit.

9.1.6.6 Local Resources

Vectren prefers local resources for both capacity and energy needs. Local resources benefit Vectren customers by reducing cost risk and providing tax base, jobs and grid support for reliability. The All-Source RFP provided many attractive renewable resources in Vanderburgh, Posey, Warrick, Gibson and Spencer Counties, which Vectren is evaluating for procurement.

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 Vectren serves. Currently, Vectren generates tax revenues for primarily two counties, Posey and Warrick. The preferred portfolio will 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 Vectren 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. Vectren'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 Vectren load.

9.1.6.7 Transmission/Distribution

The preferred portfolio required the lowest number of transmission system network upgrades of all cases studied, except for the CCGT case. Although the number of network upgrades were lower than other cases, upgrades to the Vectren system import capability were identified. The upgrades identified are the replacement of three transformers for a total estimated cost of $11 million and were also required for the other non-CCGT cases studied.

The reliance on imports from the MISO market into Vectren'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 Vectren 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 $20 and $30 million to maintain reliability. This amount was not included in the NPVRR of this portfolio.

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 Vectren transmission and distribution electric system.

9.1.6.8 Economic Development

The preferred portfolio allows Vectren 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 Vectren 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 Vectren's service territory will benefit to the extent the addition of renewable energy supports growth among Vectren South's large customers or attracts new customers. The creation of additional jobs in the communities Vectren 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 also will benefit the local economy. Ultimately, renewable energy projects support the attraction and retention of large customers.

Although Vectren supports cost effective and reliable renewable energy projects, Vectren 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 base load assets must be properly balanced to continue economic growth for our region.

For industrial customers to maintain their required voltage level, the Vectren 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 CT's in the preferred portfolio provide this needed reactive power support. Even when they are not dispatched normally, CT's are able to be started and brought online quickly if needed for Vectren system reliability. CT's also prevent Vectren from entering into Reactive Power Payments through the MISO market, which would impact Vectren customers' bills.

Importantly, the current plan offers flexibility and a hedge assurance, reducing market risk for customers. Specifically, Vectren must remain nimble and dynamic for prospective industrial customers and to be able to adapt to the potential need for CCGT build out. Vectren aggressively pursues manufacturing opportunities which has direct, indirect and induced economic benefits for the region and state of Indiana. Vectren'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 Vectren 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 Vectren's ability to provide safe, reliable and cost-effective service. Vectren'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. Vectren 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 in order to even out short-term price fluctuations. Coal suppliers and transportation providers generally require firm commitments on quantities; however, Vectren coal contracts include optionality to adjust tonnage up or down to help manage operational variability which impacts inventory levels. Currently Vectren utilizes non-firm pipeline delivery and gas storage for the existing peaking units. It is planned that the future flexible combustion turbines 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

Vectren pursued all the items listed in the 2016 IRP short-term action plan.

10.1.1 Generation Transition

Following the conclusion of the 2016 IRP, Vectren began a generation transition plan to replace the majority of its coal fleet with a highly efficient large natural gas plant and a 50 MW universal solar plant. Vectren also proposed to continue operation of its most efficient coal unit by installing certain environmental compliance equipment. Vectren pursued this plan through two separate filings in Cause numbers 45052 and 45086.

In April 2019, the IURC granted partial approval of Vectren's Smart Energy Future electric generation transition plan which included approval to retrofit F.B. Culley 3, Vectren's largest, most-efficient 270 MW coal-fired unit and to proceed with construction of a 50 MW universal solar array. The request to construct a 700-850 MW combined cycle natural gas power plant was not approved.

10.1.2 DSM

The 2016 IRP did support continued energy efficiency programs designed to save 1% of eligible retail sales. Vectren proposed the 2018-2020 Electric DSM Plan to obtain approval of programs to achieve this level of savings. The Commission approved this plan on December 28, 2017 in Cause No. 44927. Consistent with the 2016 IRP, the framework for the 2018-2020 filed plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 80% eligible load.

10.1.3 Solar Projects

In 2017, Vectren filed for and received approval to construct two 2-MW universal solar projects that are currently in operation; one near North High School in northern Vanderburgh County and the second near Oak Hill Cemetery near Morgan Ave., which

is through a partnership with the City of Evansville. Both sites have been constructed and have been generating power since December of 2018. The Volkman Road project also includes battery storage with the ability to discharge one megawatt of power per hour over a four-hour period.

10.1.4 Environmental Permits for ELG/CCR

The bottom ash system at F.B. Culley Unit 3 is scheduled to be converted to a dry system in the Fall of 2020. Work is also taking place to convert the FGD system to zero liquid discharge technology. These two technologies will make Culley Unit 3 fully compliant with the Effluent Limitation Guidelines (ELG) rule and the NPDES permit requirements for Culley 3.

The West Ash Pond at F.B. Culley is currently undergoing closure, with those activities scheduled to be completed by December 2020. The closure design includes the construction of a lined contact storm water pond, which will receive 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 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 soon. Plans are currently underway to prepare 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 Aurora 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 300 MWs of wind, 700-1,000 MWs of solar and two combustion turbines (~460 MWs) to replace approximately 730 MWs of coal fired generation. Vectren will continue to monitor developments with the State of Indiana's Energy Policy Task Force and the wholesale energy market for potential changes that could alter Vectren's plan. Regardless of the outcome, Vectren must continue to plan, as some portions are more certain than others.

Vectren plans to close its smallest, most inefficient coal unit, Culley 2 (90 MWs) and Vectren's contract for joint operations of Warrick unit 4 (150 MWs) expires by the end of 2023. In order to replace this generation, Vectren plans to acquire renewable generation in the next three years in order for Vectren's customers to benefit from expiring renewables tax incentives and, at a minimum, replace this portion of Vectren's coal fleet. This equates to approximately 700-1,000 MWs of capacity from solar generation towards the 2023/2024 and the 2024/2025 MISO planning years, partially dependent on expected solar penetration levels within MISO at that time and MISO resource accreditation.

To fill this need, Vectren plans to pursue attractive projects from its 2019 All-Source RFP consistent with the findings in the 2019/2020 IRP. The All Source RFP bids remain open until August 2020 and Vectren is in active discussions with short listed bidders for various renewables projects. Upon completion of expected negotiations Vectren plans to file a CPCN in 2020 so that its customers can receive low-cost solar energy from these projects before tax incentives are reduced. The remainder of Vectren's renewable need, including wind, solar and storage, could be filled through a second RFP. Affordable pricing will be important.

Vectren's plan allows for flexibility while awaiting clarity from the outcome of the Energy Policy Task Force and resource accreditation decisions from MISO; however, preliminary planning must begin for the potential replacement of the A.B. Brown coal plants with two combustion turbines most likely as it offers many benefits at the Brown site.

In order to accommodate the need for capacity by the end of 2023 for the 2024/2025 planning season, Vectren will begin design work and obtain updated cost estimates for equipment. Additionally, permits would need to be filed with FERC to bring gas to the Brown site, a continuation of work done in support of the 2016 plan. Vectren currently has approximately 500 MWs of interconnection rights for the Brown units at this brownfield site, which will allow Vectren to bypass the MISO Generation Interconnection Queue. Utilization of the Brown site helps to mitigate risk for Vectren customers, including reliance on the capacity market and risk of future transmission upgrades at different sites or later at the Brown site. A decision on CPCN timing will be made later this year.

10.2.2 DSM

Vectren has filed its 2021-2023 electric demand side management (DSM) plan in June of 2020. The 2021-2023 energy efficiency savings were guided by the 2019/2020 IRP process. Once approved by the Commission, the Vectren Oversight Board, including the Office of Consumers Counselor (OUCC), Citizens Action Coalition (CAC) and Vectren, will oversee the implementation of energy efficiency programs.

10.2.3 Solar Projects

Based on the Commission's 2019 approval, Vectren is currently constructing a 50 MW universal solar plant, interconnecting at transmission voltage (161kV) and is expected to be in service in the first quarter of 2021.

10.2.4 Culley 3

Based on the Commission's 2019 approval, Vectren is proceeding with the installation of the F.B. Culley Unit 3 mandated environmental compliance projects. The new pollution control equipment installations are in various stages of engineering and planning with the expected in-service dates meeting the defined timelines.

10.2.5 Ability to Finance the Preferred Portfolio

The Company and its parent corporations expect to have sufficient funds to finance the preferred portfolio, through a combination of internally generated cash flow from operations and external capital markets activity.

10.2.6 Continuous Improvement

Vectren takes continuous improvement seriously and works to ensure that improvement opportunities are evaluated and where appropriate implemented. This is done in several ways. First, Vectren participates in the Director's report process and listens to critiques of its IRPs from multiple stakeholders. Second, Vectren 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, Vectren participates in stakeholder meetings of other Indiana utilities and follows stakeholder feedback in those processes. Fourth, Vectren 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.

10.3 Implementation Schedule for the Preferred Resource Portfolio

Below is a general timeline for the Preferred Resource Portfolio, subject to change pending outcome of the Energy Policy Task Force.

Figure 10-1 – Implementation Schedule

Year	Quarter	Activity
2020	Q2	File for 2021-2023 DSM Plan File IRP
	Q3	Select Attractive Renewable Projects from All-Source RFP
	Q4	File CPCN for Renewable Projects Second RFP
2021	Q1	File CPCN for Combustion Turbines Results of 2nd RFP in
	Q2	
	Q3	Renewables CPCN Order
	Q4	Begin 2022 IRP Combustion Turbines CPCN Order
2022	Q1	
	Q2	
	Q3	
	Q4	File 2022 IRP

SECTION 11
TECHNICAL APPENDIX

11.1 CUSTOMER ENERGY NEEDS APPENDIX

11.1.1 Forecast Inputs

11.1.1.1 Energy Data

Historical Vectren sales and revenues data were obtained through an internal database. The internal database 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 exported out of the database and 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 provided by Moody's Economy.com for the nation, the state of Indiana and the Evansville Metropolitan Statistical Area (MSA). Moody's Economy.com, a division of Moody's Analytics, is a trusted source for economic data that is commonly utilized by utilities for forecasting electric sales. The monthly data provided to Vectren 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, obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. 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

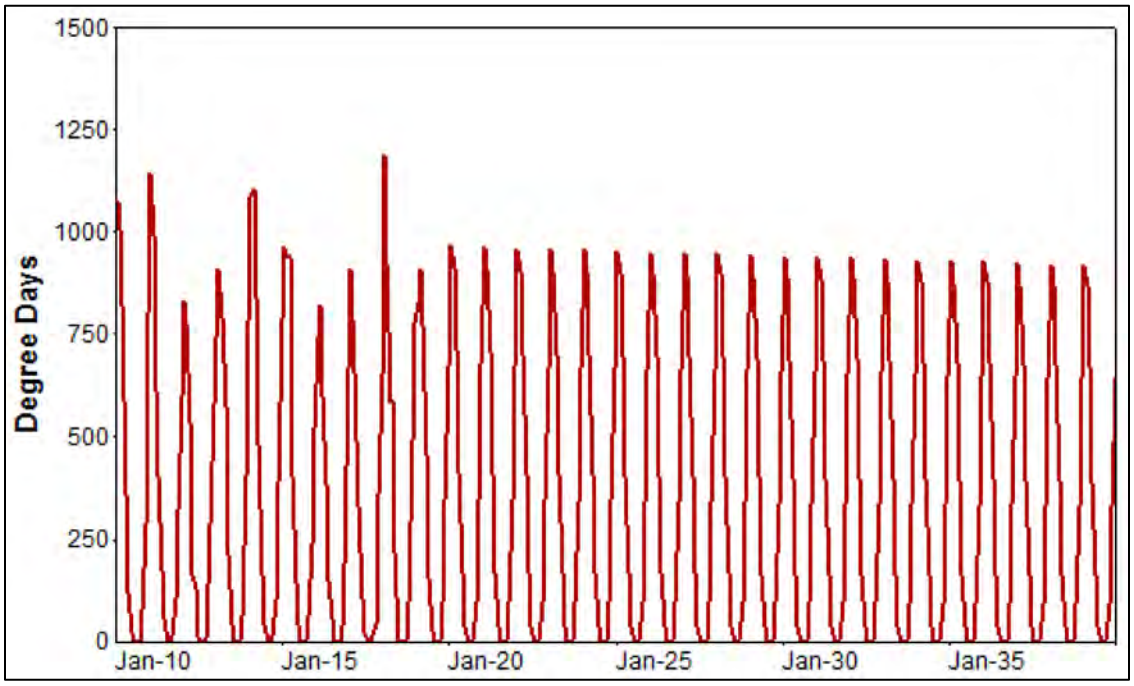
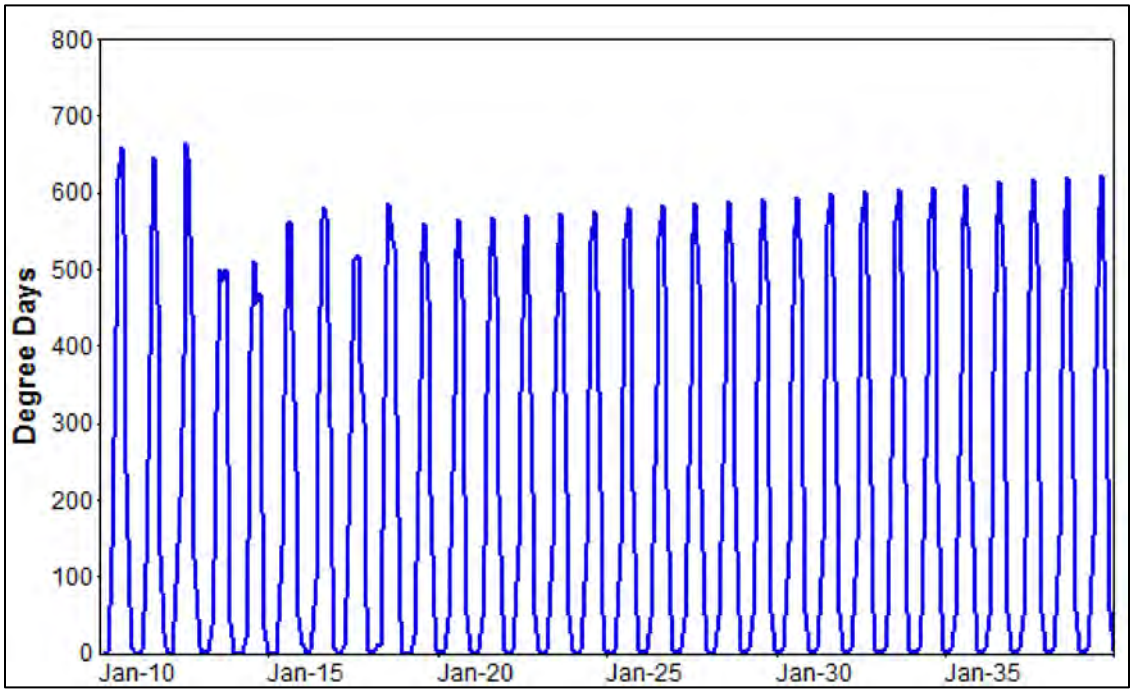


Figure 11.2 – Cooling Degree Days



11.1.1.4 Equipment Efficiencies and Market Shares Data

Itron Inc. provides regional Energy Information Administration (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. Vectren conducted an Electric Baseline survey in the third quarter of 2016 of Vectren's residential customers. This data was utilized to compare its territory market share data with the regional EIA data. In order to increase the accuracy of the residential average use model, regional equipment market shares were altered to reflect those of Vectren's actual territory. Appliance saturation surveys are conducted every 2-4 years, depending on need.

11.1.2 Load Forecast Continuous Improvement

Itron continues to improve and evolve the SAE (Statistically Adjusted End-Use) modeling framework. In addition to annually updating efficiency and saturations projections with the latest estimates from the EIA (Energy Information Administration) 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 Vectren forecast now also takes into account emerging technologies: customer distributed generation and electric vehicles. Customer owned photo-voltaic (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 EIA's forecast of vehicle adoption. The EIA uses 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, Vectren continually stays up to date with load forecasting topics in a variety of ways. First, Vectren 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. Vectren 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. Vectren forecasters periodically attend continuing education workshops and webinars on various forecasting topics to help improve skills and learn new techniques. Additionally, Vectren discusses forecasts with the State Utility Forecasting Group and other Indiana utilities to better understand their forecasts. Vectren compares Vectren 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 Vectren's energy and demand forecasts over the last several IRPs by comparing Weather Normalized (WN) sales and demand figurers to IRP forecasts from 2009-2018.

Weather-normalization is performed each month by importing customer count, meter read schedule, billing month sales and daily temperature into Vectren's Electric AUPC Estimation system. Underlying the Electric AUPC Estimation System is a set of MetrixND (Itron's statistical modeling software) 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 and daily system delivery data. On execution, the Use per Customer (UPC) project files read actual weather data from the Access weather database and generate daily use per customer estimates for the revenue classes. The results are exported back to the AUPC system database where the predicted daily use estimates are used to allocate billed monthly sales to the calendar-month period. The models are also executed using normal daily temperatures. Results are written back to the AUPC system database. Weather-normalized sales are then exported from the Electric AUPC Estimation system.

The following tables show the WN[46] and forecasted values for:

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

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

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

Year	2007 Total Demand Forecast (MW)	2009 Total Demand Forecast (MW)	2011 Total Demand Forecast (MW)	2014 Total Demand Forecast (MW)	2016 Total Demand Forecast (MW)	WN Total Demand (MW)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	1,216					1,069	-13.7%				
2010	1,237	1,153				1,136	-8.9%	-1.5%			
2011	1,252	1,179				1,159	-8.0%	-1.7%			
2012	1,258	1,118	1,156			1,136	-10.7%	1.6%	-1.7%		
2013	1,265	1,115	1,156			1,144	-10.5%	2.6%	-1.0%		
2014	1,272	1,107	1,165			1,133	-12.3%	2.3%	-2.8%		
2015	1,281	1,100	1,164	1,155		1,113	-15.1%	1.1%	-4.6%	-3.8%	
2016	1,290	1,092	1,160	1,156		1,087	-18.7%	-0.5%	-6.7%	-6.3%	
2017	1,299	1,094	1,151	1,113	1,082	1,038	-25.2%	-5.4%	-11.0%	-7.2%	-4.3%
2018	1,308	1,093	1,145	1,109	1,086	1,006	-30.0%	-8.6%	-13.8%	-10.2%	-7.9%
Mean Absolute Error							15.3%	2.8%	5.9%	6.9%	6.1%

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

Year	2007 Total Energy IRP Forecast (GWh)	2009 Total Energy IRP Forecast (GWh)	2011 Total Energy IRP Forecast (GWh)	2014 Total Energy IRP Forecast (GWh)	2016 Total Energy IRP Forecast (GWh)	WN Total Energy Results (GWh)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	6,090					5,365	-13.5%				
2010	6,230	5,306				5,701	-9.3%	6.9%			
2011	6,329	5,460				5,819	-8.8%	6.2%			
2012	6,369	5,456	5,837			5,718	-11.4%	4.6%	-2.1%		
2013	6,422	5,434	5,807			5,743	-11.8%	5.4%	-1.1%		
2014	6,476	5,403	5,803			5,797	-11.7%	6.8%	-0.1%		
2015	6,527	5,365	5,772	5,914		5,773	-13.1%	7.1%	0.0%	-2.4%	
2016	6,580	5,336	5,725	5,936		5,725	-14.9%	6.8%	0.0%	-3.7%	
2017	6,629	5,315	5,657	5,514	5,257	5,073	-30.7%	-4.8%	-11.5%	-8.7%	-3.6%
2018	6,680	5,292	5,590	5,503	5,290	5,139	-30.0%	-3.0%	-8.8%	-7.1%	-2.9%
Mean Absolute Error							15.5%	5.7%	3.4%	5.5%	3.3%

Figure 11.5 – Residential Energy (GWh)

Year	2007 Res. IRP Forecast (GWh)	2009 Res. IRP Forecast (GWh)	2011 Res. IRP Forecast (GWh)	2014 Res. IRP Forecast (GWh)	2016 Res. IRP Forecast (GWh)	WN Res. Results (GWh)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	1,595					1,512	-5.5%				
2010	1,620	1,467				1,483	-9.2%	1.1%			
2011	1,645	1,440				1,460	-12.7%	1.3%			
2012	1,663	1,421	1,462			1,437	-15.7%	1.1%	-1.7%		
2013	1,683	1,391	1,419			1,421	-18.4%	2.1%	0.1%		
2014	1,703	1,365	1,399			1,412	-20.6%	3.3%	0.9%		
2015	1,722	1,332	1,371	1,404		1,444	-19.2%	7.8%	5.1%	2.8%	
2016	1,742	1,304	1,340	1,394		1,416	-23.0%	7.9%	5.4%	1.5%	
2017	1,759	1,282	1,305	1,383	1,407	1,398	-25.8%	8.3%	6.7%	1.1%	-0.6%
2018	1,777	1,264	1,271	1,377	1,395	1,375	-29.2%	8.1%	7.6%	-0.2%	-1.5%
Mean Absolute Error							17.9%	4.6%	3.9%	1.4%	1.1%

Figure 11.6 – Commercial (GS) Energy (GWh)

Year	2007 Comm. (GS) IRP Forecast (GWh)	2009 Comm. (GS) IRP Forecast (GWh)	2011 Comm. (GS) IRP Forecast (GWh)	2014 Comm. (GS) IRP Forecast (GWh)	2016 Comm. IRP Forecast (GWh)	WN Comm. (GS) Results (GWh)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	1,384					1,319	-4.9%				
2010	1,404	1,275				1,314	-6.8%	3.0%			
2011	1,426	1,284				1,307	-9.1%	1.8%			
2012	1,438	1,296	1,375			1,283	-12.1%	-1.0%	-7.2%		
2013	1,455	1,304	1,383			1,294	-12.4%	-0.7%	-6.9%		
2014	1,472	1,307	1,399			1,312	-12.2%	0.4%	-6.6%		
2015	1,490	1,306	1,402	1,304		1,321	-12.8%	1.1%	-6.2%	1.3%	
2016	1,507	1,306	1,398	1,320		1,281	-17.7%	-1.9%	-9.1%	-3.0%	
2017	1,525	1,309	1,384	1,315	1,315	1,278	-19.3%	-2.4%	-8.3%	-2.9%	-2.9%
2018	1,544	1,311	1,373	1,311	1,324	1,235	-25.0%	-6.1%	-11.1%	-6.1%	-7.2%
Mean Absolute Error							13.2%	2.0%	7.9%	3.3%	5.1%

Figure 11.7 – Industrial (Large) Energy (GWh)

Year	2007 Ind. (Large) IRP Forecast (GWh)	2009 Ind. (Large) IRP Forecast (GWh)	2011 Ind. (Large) IRP Forecast (GWh)	2014 Ind. (Large) IRP Forecast (GWh)	2016 (Large) IRP Forecast (GWh)	WN Ind. (Large) Results (GWh)	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.	2016 % Diff.
2009	2,820					2,251	-25.3%				
2010	2,921	2,281				2,601	-12.3%	12.3%			
2011	2,980	2,445				2,744	-8.6%	10.9%			
2012	2,999	2,449	2,687			2,714	-10.5%	9.8%	1.0%		
2013	3,014	2,449	2,693			2,744	-9.8%	10.7%	1.9%		
2014	3,028	2,446	2,693			2,786	-8.7%	12.2%	3.3%		
2015	3,040	2,445	2,688	2,916		2,722	-11.7%	10.1%	1.2%	-7.1%	
2016	2,718	2,447	2,679	2,932		2,722	0.2%	10.1%	1.6%	-7.7%	
2017	2,730	2,446	2,664	2,546	2,211	2,097	-30.2%	-16.7%	-27.1%	-21.4%	-5.5%
2018	2,742	2,440	2,646	2,547	2,252	2,182	-25.7%	-11.9%	-21.3%	-16.7%	-3.2%
Mean Absolute Error							14.3%	11.6%	8.2%	13.3%	4.3%

11.1.3.1 Actual and Weather Normalized Energy and Demand Levels

Figure 11.8 – Historic Peak Demand

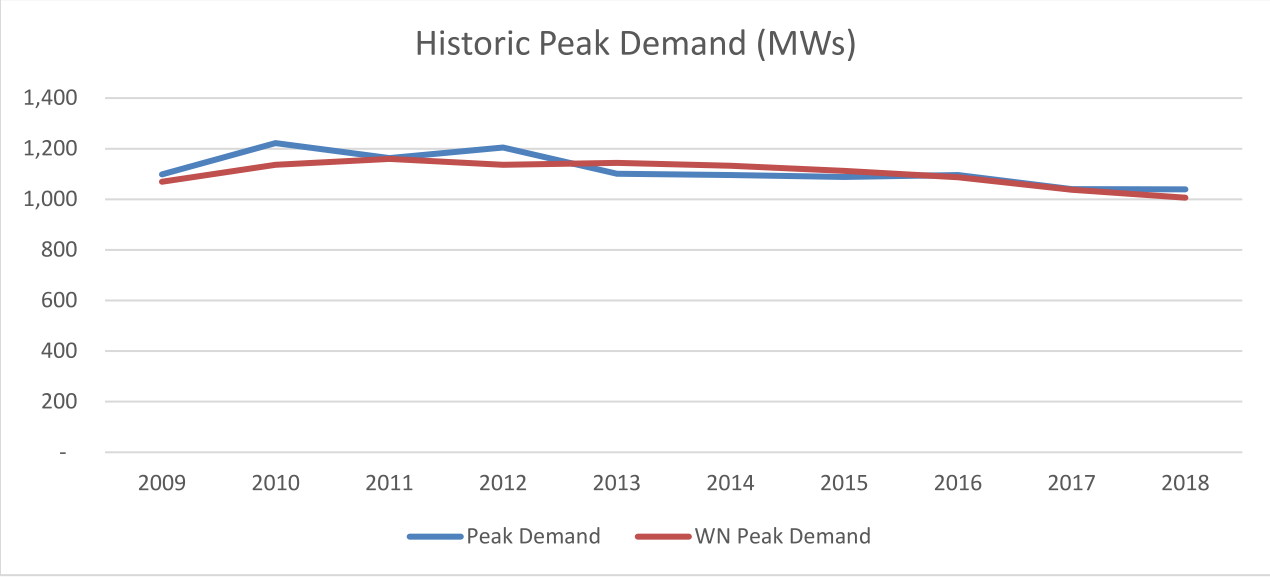
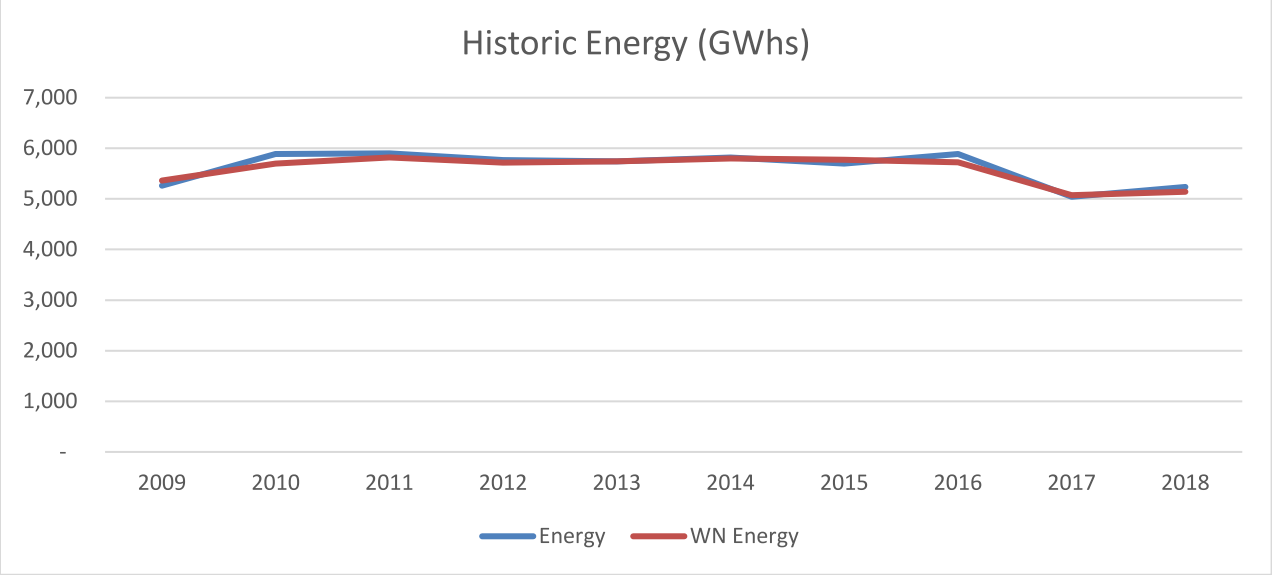


Figure 11.9 – Historic Energy



11.1.3.2 Load Shapes

Figure 11.10 – Historic Annual Load Shape

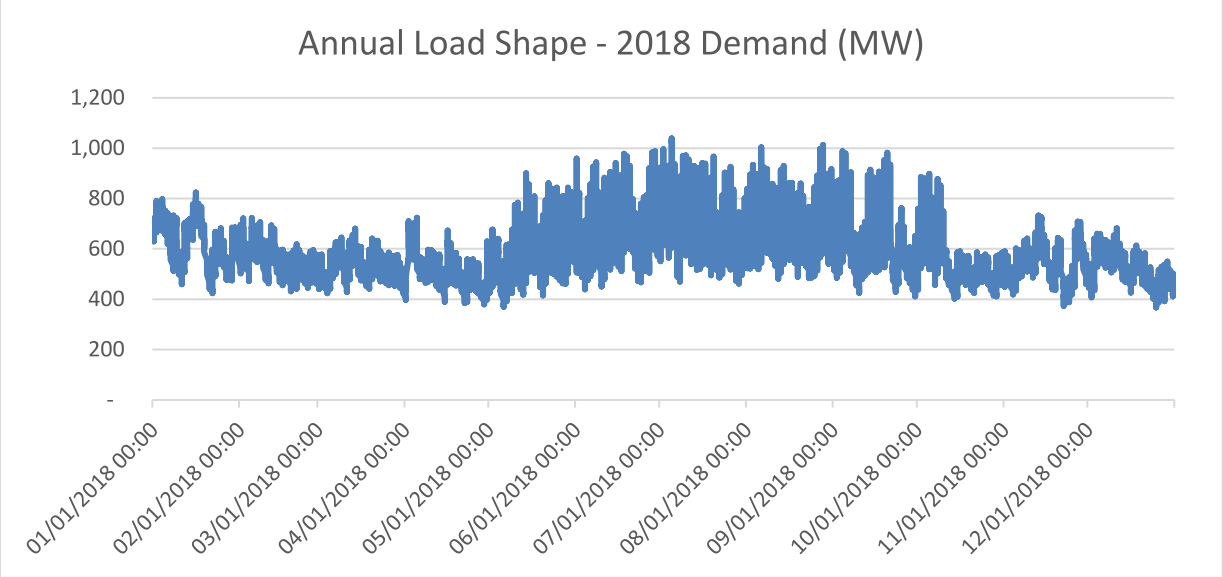


Figure 11.11 – Winter Peak Day

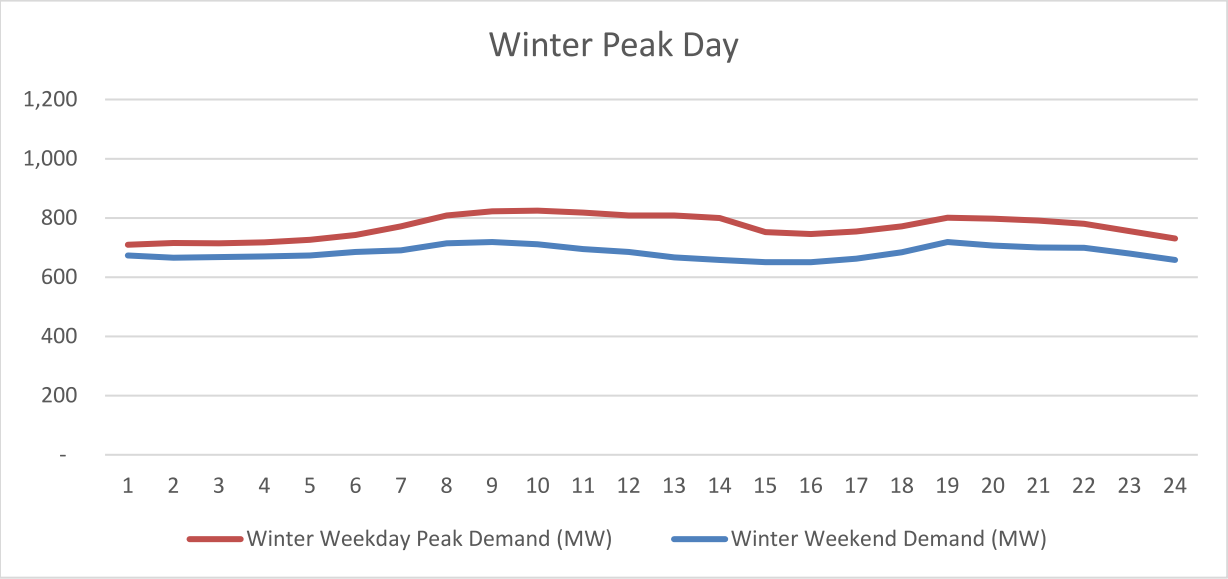


Figure 11.12 – Typical Spring Day

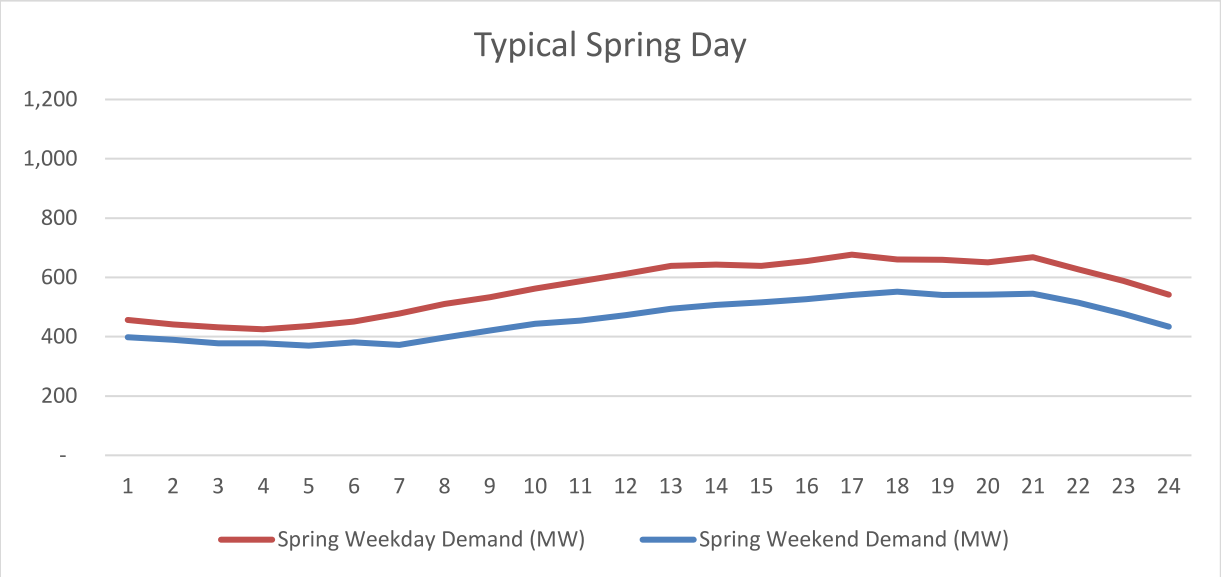


Figure 11.13 – Summer Peak Day

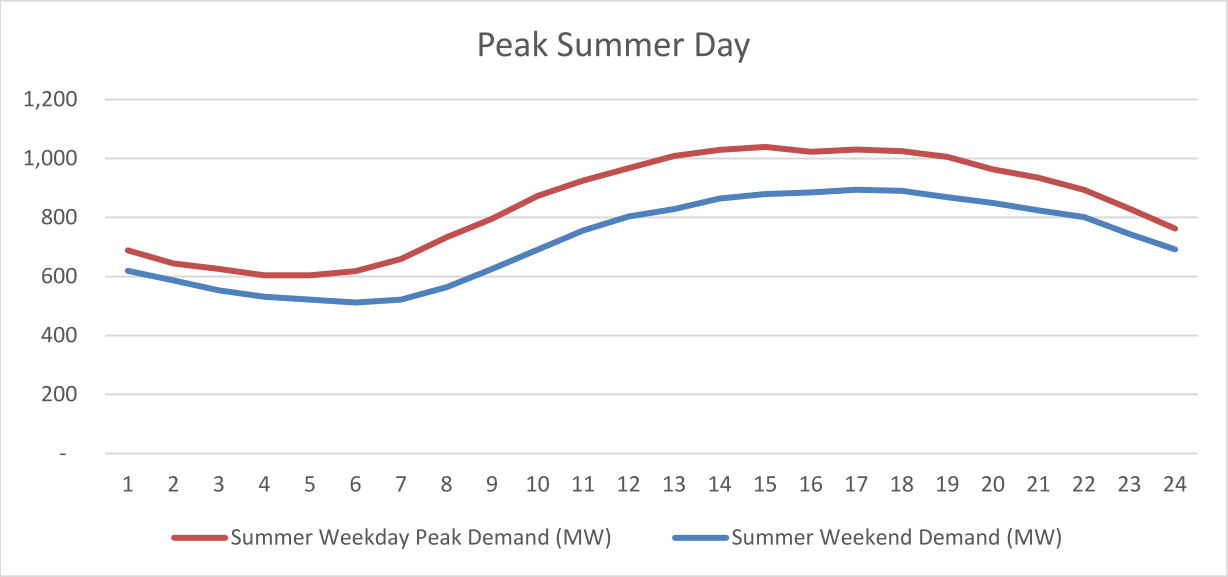


Figure 11.14 – Typical Fall Day

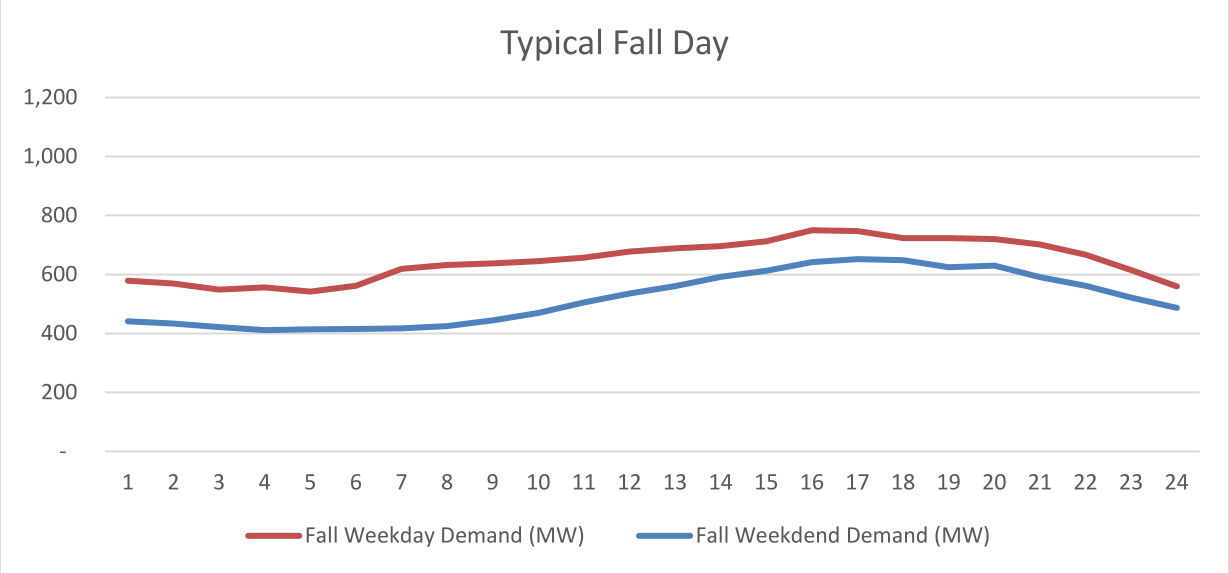


Figure 11.15 – January Load

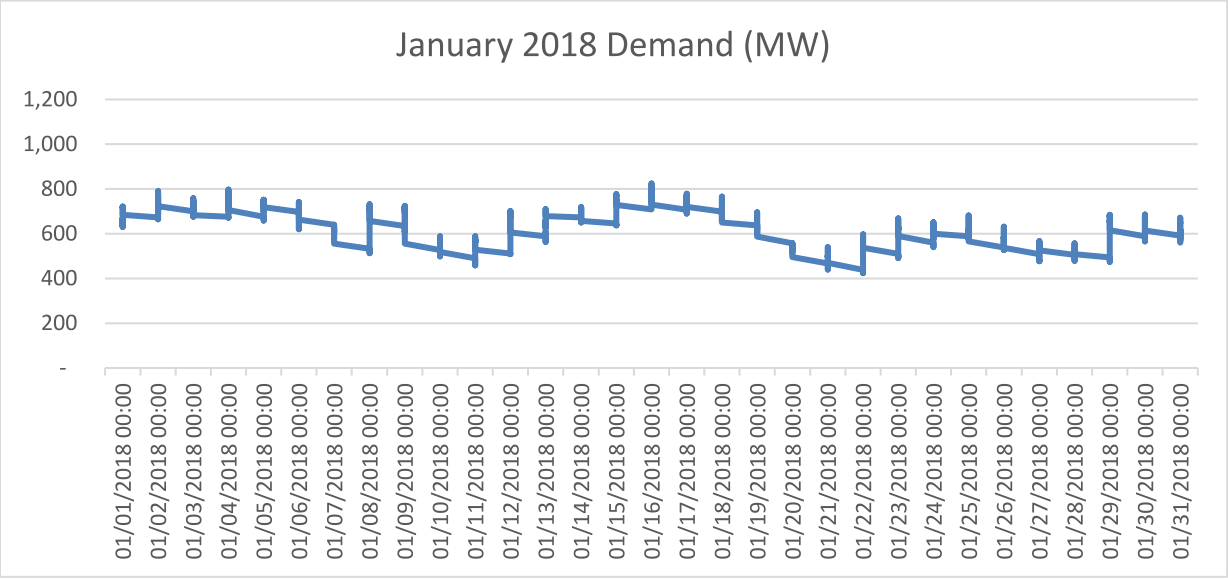


Figure 11.16 – February Load

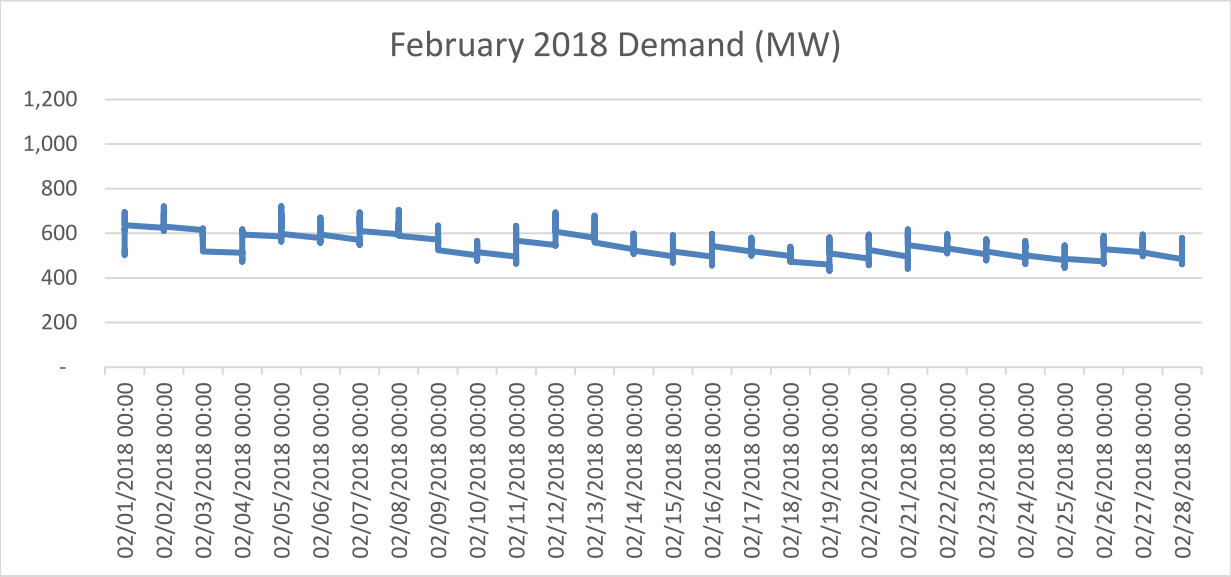


Figure 11.17 – March Load

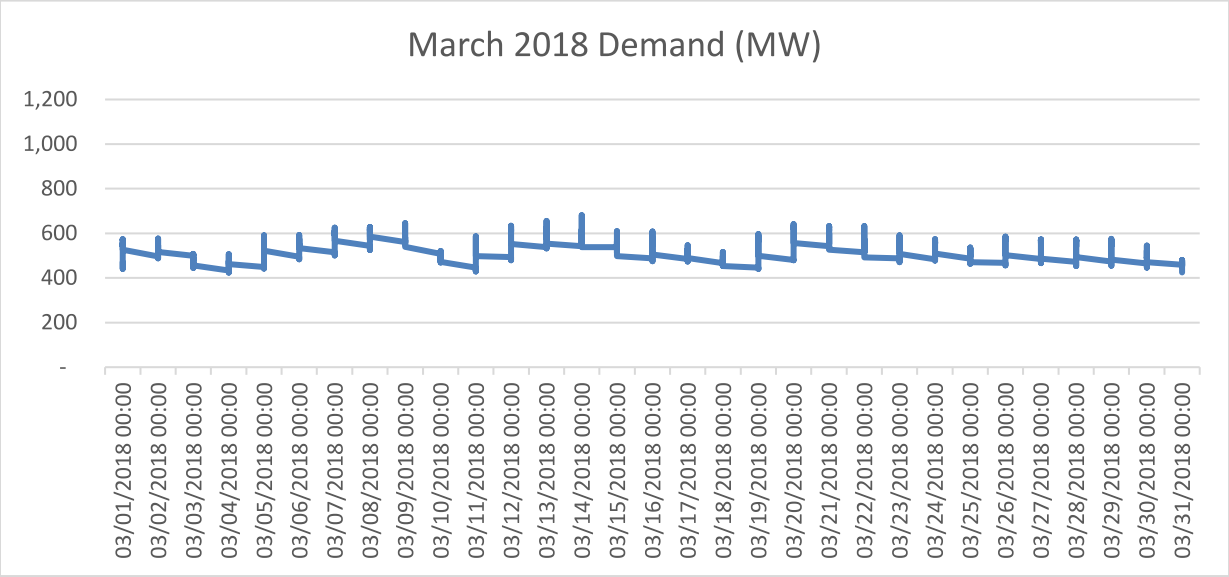


Figure 11.18 – April Load

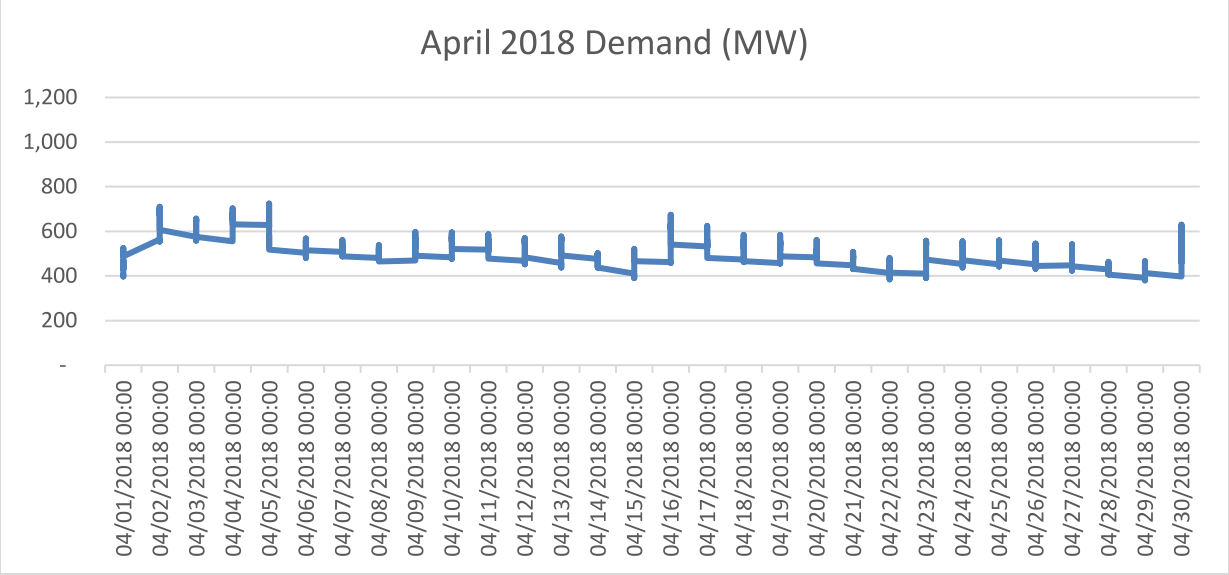


Figure 11.19 – May Load

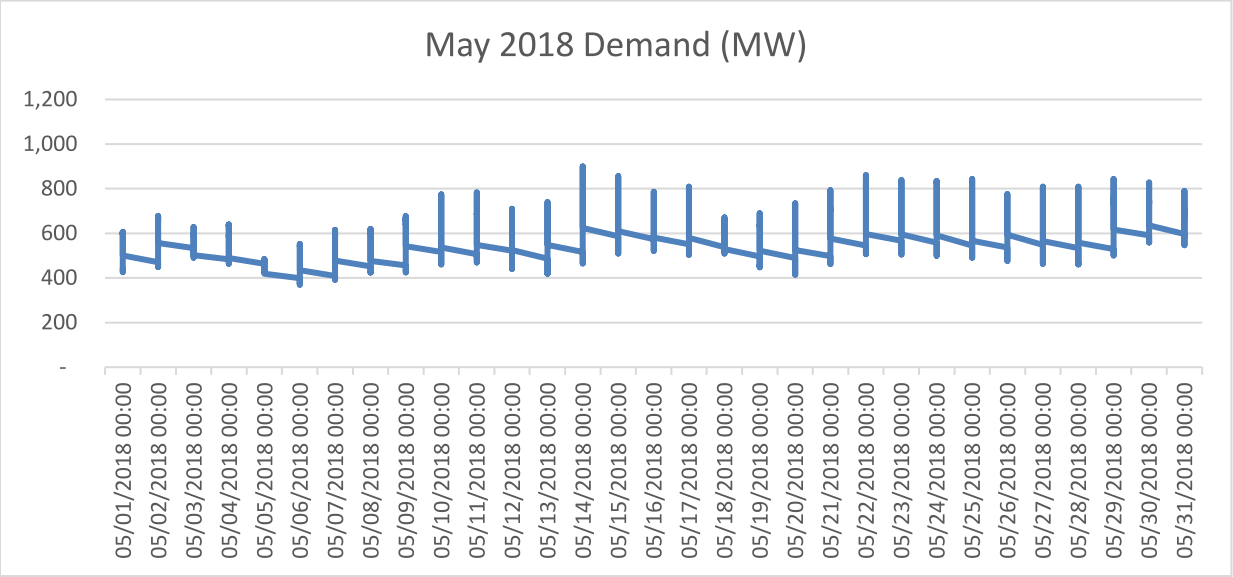


Figure 11.20 – June Load

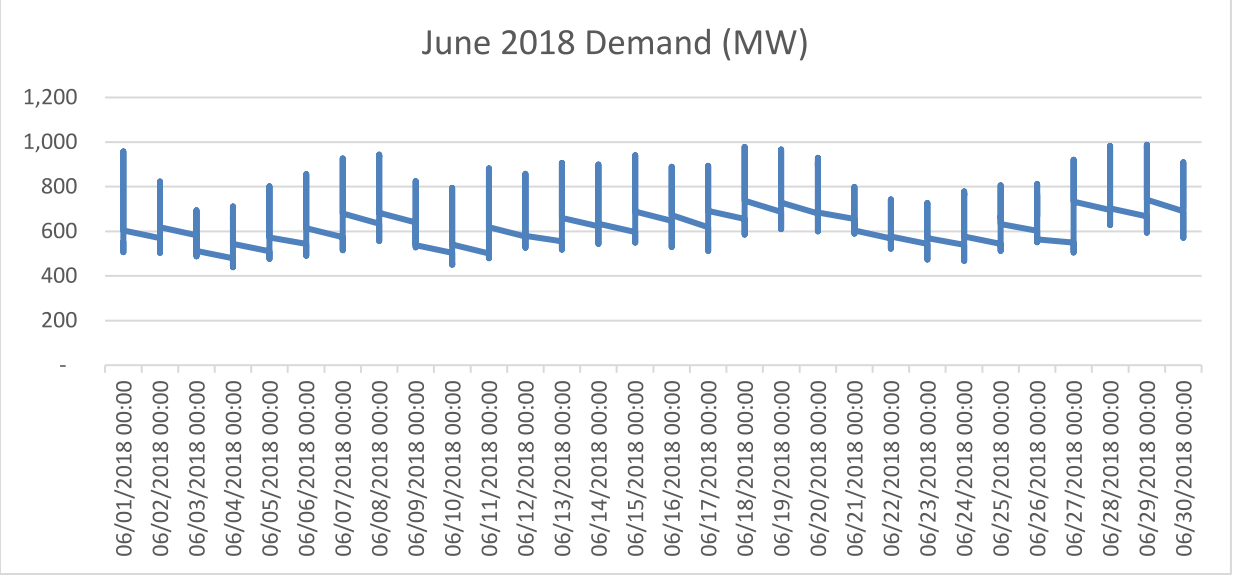


Figure 11.21 – July Load

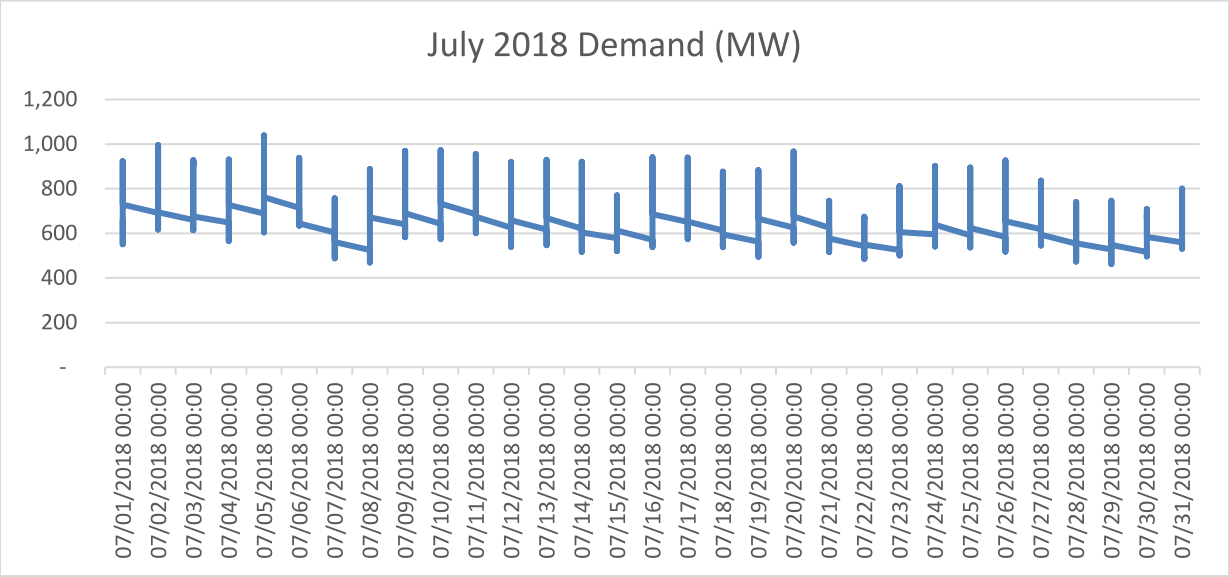


Figure 11.22 – August Load

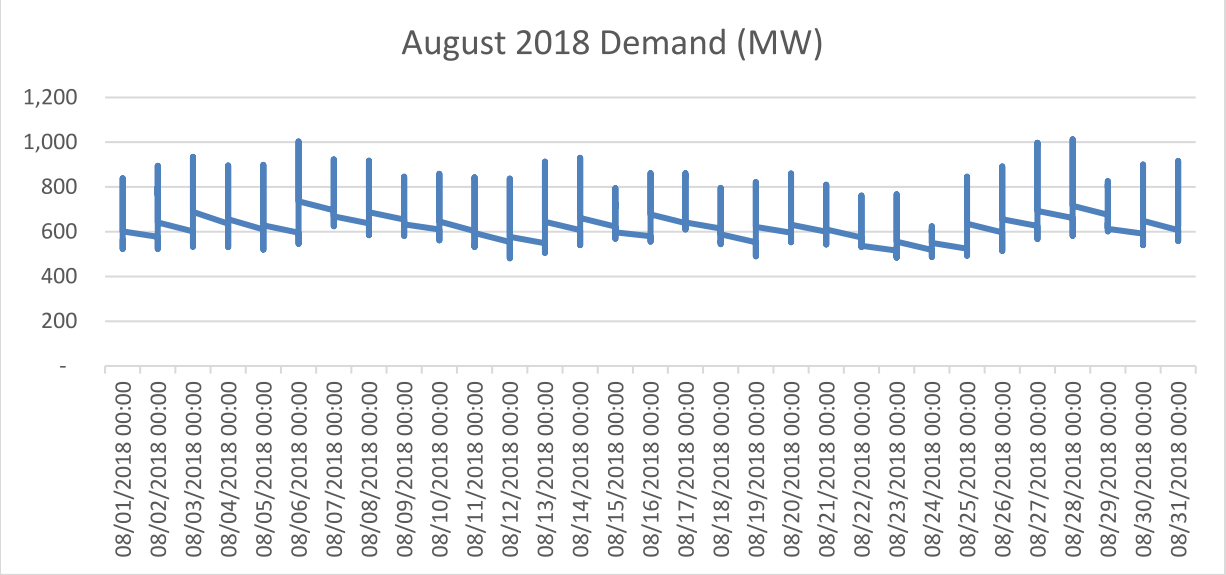


Figure 11.23 – September Load

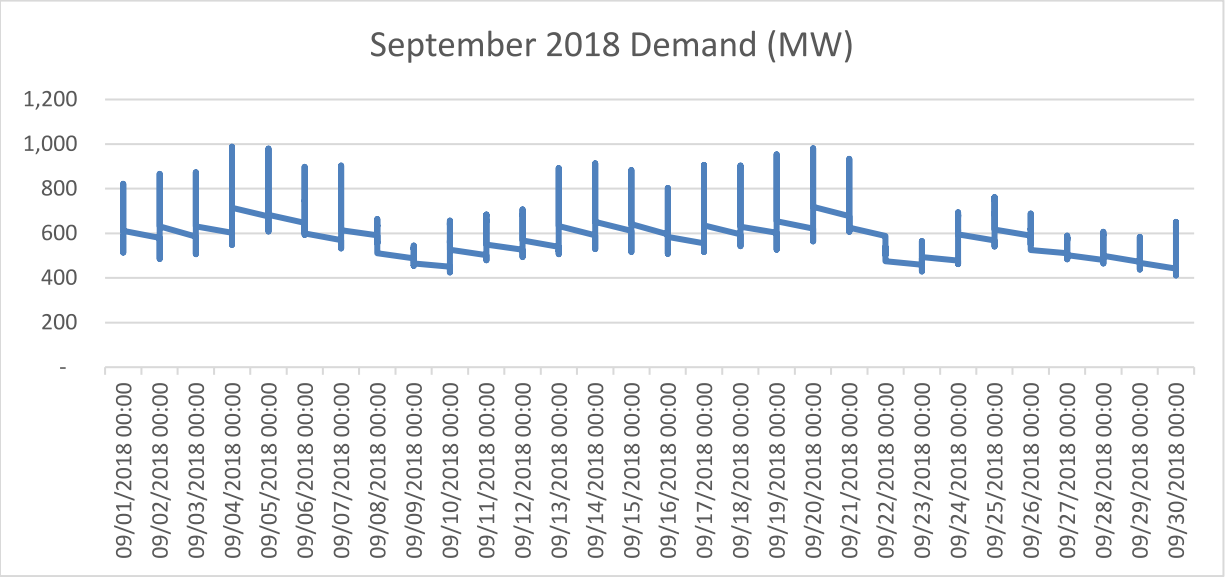


Figure 11.24 – October Load

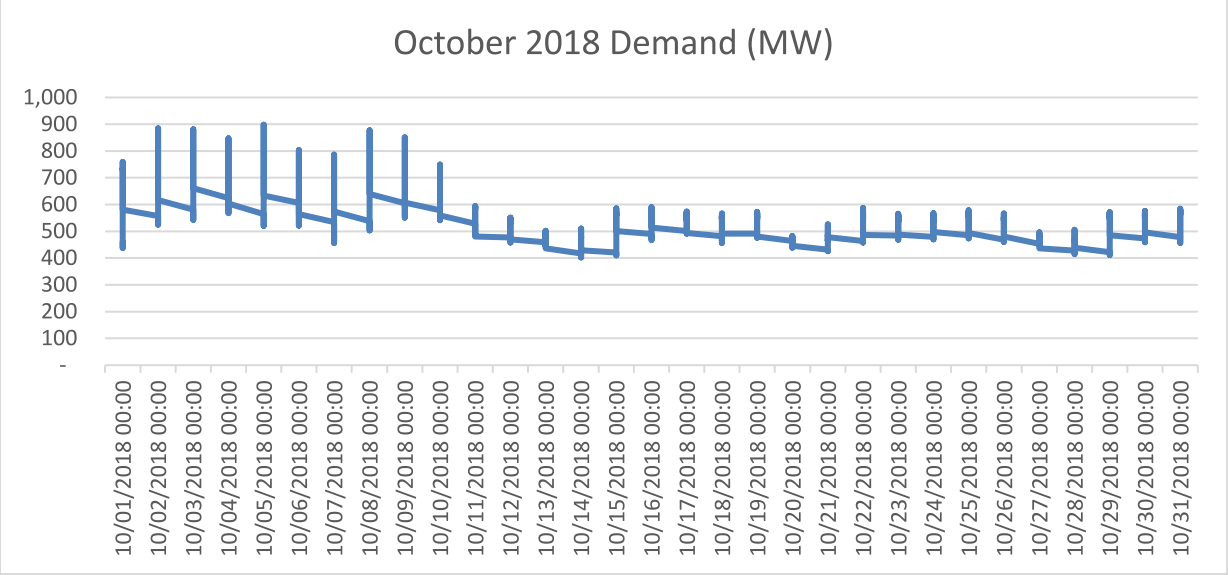


Figure 11.25 – November Load

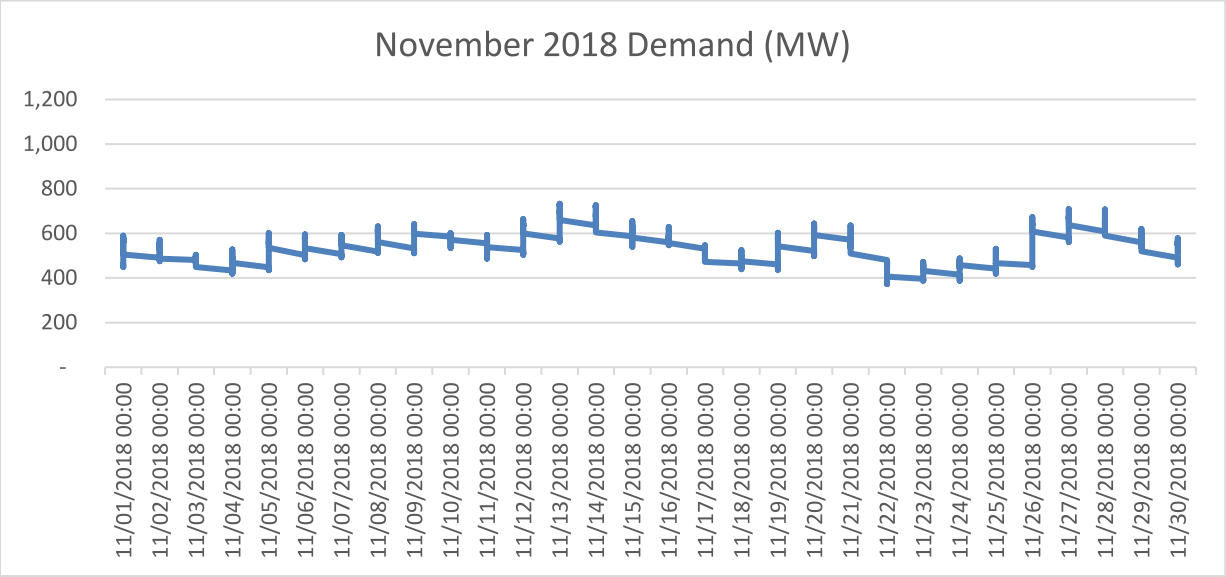
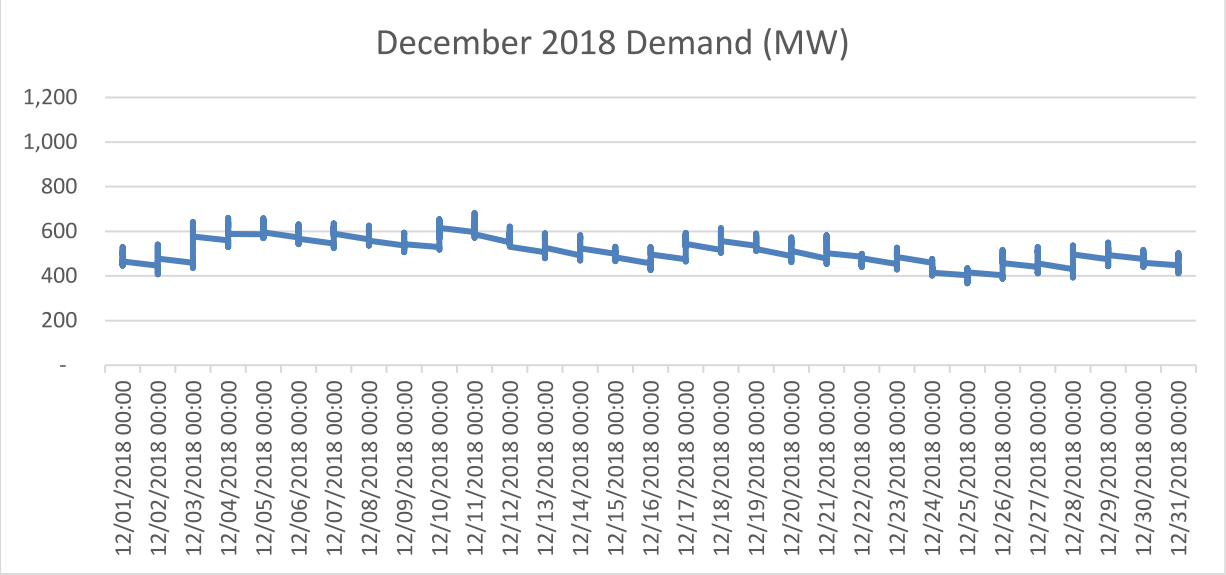


Figure 11.26 – December Load



11.2 ENVIRONMENTAL APPENDIX

11.2.1 Air Emissions

It was assumed that current or future generation resources would not exceed Vectren's allocated SO_2 and NOx emission allowances. Vectren'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. 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	245
NO_X	Low NO_X Burner	SCR	SCR	SCR	SCR
SO_2	FGD	FGD	FGD	FGD	FGD
PM	ESP	FF	ESP	FF	ESP
MATs	Shared w/ U3	Injection	Injection	Injection	Injection
SO_3		Injection	Injection	Injection	injection

Figure 11.28 – CSAPR SO_2 Allowances

SO_2				
	A.B. Brown	F.B. Culley	SIGECO W4	Total
2016	7,894	4,411	2,892	15,197
2017	4,423	3,890	1,620	9,933
2018	4,423	3,890	1,620	9,933
2019	4,423	3,890	1,620	9,933

NOx					
	A.B. Brown	BAGS[47]	F.B. Culley	SIGECO W4	Total
2016	1,214	21	1,060	445	2,740
2017	1,195	21	1,044	437	2,697
2018	1,195	21	1,044		2,698
2019	1,195	21	1,044	437	2,697

[47] Retired

Figure 11.29 – CSAPR Seasonal NOx Allowances

	A.B. Brown	BAGS[48]	F.B. Culley	SIGECO W4	Total
2016	1,214	21	1,060	445	2,740
2017	658	6	465	227	1,356
2018	658	6	465	227	1,356
2019	658	6	465	227	1,356

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). During the fall of 2009, Vectren finalized construction of a dry fly ash silo and barge loading facility that would allow for the beneficial reuse of Vectren-generated fly ash. Since February 2010, the majority of A.B. Brown fly ash is diverted to the new dry ash handling system and sent for beneficial reuse to a cement processing plant in St. Genevieve, Missouri via a river barge loader and conveyor system. 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 Vectren'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.

Fly ash from the F.B. Culley facility is similarly transported off-site for beneficial reuse in cement. In May 2009, Culley began trucking fly ash to the St. Genevieve cement plant. Upon completion of the barge loading facility at the A.B. Brown facility in late 2009, F.B. Culley's fly ash is now transported to the A.B. Brown loading facility and shipped to the cement plant via river barge. The F.B. Culley facility sends its bottom ash to the East ash pond via wet sluicing. The pond is approximately 10 acres in size. By the end of 2020, the East pond will no longer receive bottom ash as a result of the conversion to a dry system. The West pond (32 acres) no longer receives bottom ash but has continued to accept coal pile run-off and general storm water from the west side of the plant, including the plant entrance road. By the end of 2020, the West pond will be closed. The closure

[48] Retired

project includes the construction of a new geosynthetic lined contact storm water pond that will receive 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 Vectren'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

Vectren'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 National Pollutant Discharge Elimination System (NPDES) water discharge permits issued by the Indiana Department of Environmental Management (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 Vectren'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 Vectren, the IRP is not the appropriate tool to determine which specific

programs to include in a DSM plan. Instead, every 2-3 years Vectren 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. Vectren considers the results of each test and ensures that the portfolio passes the Total Resource Cost (TRC) 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 Total Resource Cost (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, Vectren 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 5.3.2.8.1 – Vectren 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
Utility 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 2018-2020 Plan

Figure 11.30 – 2018-2020 Plan Gross kWh Energy Savings

	2018		2019		2020	
Sector	Gross kWh Energy Savings	kW Demand Savings	Gross kWh Energy Savings	kW Demand Savings	Gross kWh Energy Savings	kW Demand Savings
Residential	23,302,096	6,417	23,337,912	4,846	19,294,127	5,977
Commercial & Industrial	24,931,097	3,656	20,500,000	4,321	17,053,515	1,773
Total	48,233,193	10,073	43,837,912	9,167	36,347,642	7,750

* 2018 Evaluated Savings used for 2018
** 2019 Operating Plan used for 2019
*** 2020 Filed Plan used for 2020

11.3.3 DSM Programs

Vectren has offered tariff-based DSM resource options to customers for several years. Consistent with a settlement approved in 2007 in Cause No. 43111, the Demand Side Management Adjustment ("DSMA") was created to specifically recover all Vectren's Commission approved DSM costs, including (at that time) a DLC Component. The Commission, in its order in Cause No. 43427, authorized Vectren 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.

11.3.4 Impacts

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

Figure 11.31 – 2018 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 Lighting	Residential	235,192	58%	8,136,654	35	4,706,664	1,121	0.005	649.0
Residential Prescriptive	Residential	6,900	68%	3,326,588	482	2,277,461	1,667	0.242	1,098.0
Residential New Construction	Residential	145	54%	162,407	1,120	87,700	62	0.428	34.0
Home Energy Assessments	Residential	350	75%	341,133	975	256,938	31	0.089	23.0
Income Qualified Weatherization	Residential	2,043	100%	931,314	456	931,314	100	0.049	100.0
Energy Efficient Schools	Residential	2,401	100%	712,638	297	712,638	76	0.032	76.0
Residential Behavioral Savings	Residential	41,400	100%	7,063,475	171	7,063,475	1,839	0.044	1,838.7
Appliance Recycling	Residential	1,300	67%	1,326,520	1,020	891,359	169	0.130	114.0
BYOT (Bring Your Own Thermostat)	Residential	400	100%				358	0.895	358.0
SmartDLC - Wifi DR/DLC Changeout	Residential	1,043	100%	379,779	364	379,779	866	0.831	866.4
Community Based - LED Lighting	Residential	44,189	100%	921,588	21	921,588	127	0.003	127.0
Evaluated Nonparticipant Spillover	Residential					1,012,564			
Commercial & Industrial Prescriptive	Commercial	37,200	84%	18,605,544	500	15,628,657	2,713	0.073	2,278.7
Commercial & Industrial Custom	Commercial	40	85%	2,512,038	62,801	2,135,232	324	8.100	276.0
Small Business Direct Install	Commercial	138	101%	3,813,515	27,634	3,837,960	619	4.486	623.0
Portfolio Total		372,741	85%	48,233,193	129	40,843,329	10,073	0.027	8,461.8

* Participants are the Verified installations

Figure 11.32 – 2019 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 Lighting	Residential	241,418	72%	8,340,633	35	6,005,256	939	0.004	675.7
Residential Prescriptive	Residential	4,314	53%	2,318,054	537	1,228,569	957	0.222	507.2
Residential New Construction	Residential	171	50%	157,033	918	78,517	90	0.526	45.0
Home Energy Assessments	Residential	400	99%	403,067	1,008	399,036	42	0.105	41.6
Income Qualified Weatherization	Residential	851	100%	546,248	642	546,248	95	0.112	95.0
Energy Efficient Schools	Residential	2,500	100%	962,750	385	962,750	108	0.043	108.0
Residential Behavioral Savings	Residential	41,400	100%	7,370,000	178	7,370,000	961	0.023	961.0
Appliance Recycling	Residential	1,500	53%	1,491,900	995	790,707	198	0.132	104.9
BYOT (Bring Your Own Thermostat)	Residential	400	100%				240	0.600	240.0
SmartDLC - Wifi DR/DLC Changeout	Residential	1,000	100%	198,000	198	198,000	1,015	1.015	1,014.5
Community Based - LED Lighting	Residential	50,496	100%	1,550,227	31	1,550,227	202	0.004	202.0
Commercial & Industrial Prescriptive	Commercial	40,179	75%	13,500,000	336	10,125,000	3,612	0.090	2,709.0
Commercial & Industrial Custom	Commercial	44	96%	3,500,000	79,545	3,360,000	450	10.227	432.0
Small Business Direct Install	Commercial	78	86%	3,500,000	44,872	3,010,000	259	3.321	222.7
Portfolio Total		384,751	81%	43,837,912	114	35,624,309	9,167	0.024	7,358.7

Figure 11.333 – 2020 Electric DSM Filed Plan Program Savings

Program	Residential/ Commercial	Participants	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross kW/ Participant	Net KW
Residential Lighting	Residential	163,416	67%	6,075,005	37	4,070,253	791	0.005	530.0
Residential Prescriptive	Residential	6,595	52%	1,979,280	300	1,029,226	1,910	0.290	993.3
Residential New Construction	Residential	139	50%	187,038	1,346	93,519	118	0.849	59.0
Home Energy Assessments	Residential	1,210	98%	863,991	714	846,711	192	0.159	188.2
Income Qualified Weatherization	Residential	525	100%	1,130,945	2,154	1,130,945	540	1.029	540.2
Energy Efficient Schools	Residential	2,600	100%	645,216	248	645,216	53	0.020	52.8
Residential Behavioral Savings	Residential	35,298	100%	5,600,000	159	5,600,000	1,153	0.033	1,153.0
Appliance Recycling	Residential	920	54%	884,915	962	477,854	117	0.127	63.1
Conservation Voltage Reduction	Residential	5,324	100%	1,461,047	274	1,461,047	263	0.049	263.1
BYOT (Bring Your Own Thermostat)	Residential	400	100%				240	0.600	240.0
SmartDLC - Wifi DR/DLC Changeout	Residential	1,000	100%	466,690	467	466,690	600	0.600	600.0
Community Based - LED Lighting	Residential								
Commercial & Industrial Prescriptive	Commercial	6,856	87%	5,002,621	730	4,352,280	369	0.054	321.0
Commercial & Industrial Custom	Commercial	93	100%	7,002,080	75,291	7,002,080	633	6.806	633.0
Small Business Direct Install	Commercial	131	95%	4,016,159	30,658	3,821,144	585	4.466	556.7
Conservation Voltage Reduction	Commercial	558	100%	1,032,655	1,851	1,032,655	186	0.333	185.9
Portfolio Total		225,065	88%	36,347,642	161	32,029,620	7,750	0.034	6,379.2

11.3.5 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 Vectren system marginal energy cost from the base optimized scenario under base assumptions. This included emission cost for CO_2 starting in 2027, 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 **	CO2 Forecast $/Ton	System Marginal Cost $/MWh***
2020	$148.60	$6.36	**$154.96**	$2.98	$0.00	$28.63
2021	$151.87	$6.43	**$158.30**	$3.16	$0.00	$30.06
2022	$155.21	$6.55	**$161.76**	$3.37	$0.00	$34.99
2023	$158.63	$6.73	**$165.35**	$3.63	$0.00	$35.77
2024	$162.12	$6.71	**$168.82**	$3.83	$0.00	$36.81
2025	$165.68	$6.83	**$172.51**	$4.00	$0.00	$38.82
2026	$169.33	$6.99	**$176.31**	$4.19	$0.00	$39.80
2027	$173.05	$7.15	**$180.20**	$4.35	$4.34	$44.04
2028	$176.86	$7.32	**$184.18**	$4.52	$5.07	$46.36
2029	$180.75	$7.50	**$188.25**	$4.68	$6.48	$48.37
2030	$184.73	$7.63	**$192.36**	$4.87	$7.95	$50.18
2031	$188.79	$7.81	**$196.60**	$5.06	$8.80	$51.76
2032	$192.94	$7.98	**$200.93**	$5.27	$9.68	$52.59
2033	$197.19	$8.16	**$205.35**	$5.51	$10.60	$54.94
2034	$201.53	$8.34	**$209.87**	$5.73	$11.56	$56.60

Year	Avoided Capital/O&M Cost $/kW*	Transmission & Distribution Avoided Capital Cost $/kW	Total Capacity Avoided Cost $/kW	Natural Gas Forecast $/MMBtu **	CO2 Forecast $/Ton	System Marginal Cost $/MWh***
2035	$205.96	$8.52	**$214.48**	$6.02	$13.29	$59.93
2036	$210.49	$8.71	**$219.20**	$6.23	$15.09	$61.52
2037	$215.12	$8.90	**$224.02**	$6.48	$16.97	$64.69
2038	$219.86	$9.10	**$228.95**	$6.70	$19.71	$69.00
2039	$224.69	$9.30	**$233.99**	$6.90	$23.36	$72.04

***Transmission costs derived from switchyard upgrade on brownfield A.B. Brown site**

***Distribution costs derived from average investment per lot**

****Assumes average of winter/summer delivered to S. Indiana**

*****Based on Vectren Reference Case (Around-the-Clock prices shown)**

11.3.6 Estimated Impact on Historical and Forecasted Peak Demand and Energy

11.4 RESOURCE OPTIONS APPENDIX

11.4.1 Existing Resource Studies

11.4.1.1 Existing Brown Scrubber Assessment

Both A.B. Brown units are scrubbed for sulfur dioxide (SO2) emissions, utilizing a dual-alkali flue gas desulfurization (FGD) process. The FGD systems were included as part of the original unit design and construction. A.B. Brown Unit 1 FGD has reached 40 years of service life and Unit 2 FGD has reached 33 years of service life as of 2019. The operating life of these scrubbers has been impacted by a combination of the acidic and caustic dual-alkali conditions, which are both very damaging to structural steel and concrete. Continual maintenance and repairs have been completed throughout the many years of service. Despite these continuous repair and maintenance efforts, many steel elements and foundations exhibit severe corrosion. Structural assessment studies have been completed by a local engineering firm, Three i Design. Major replacements and repairs have been identified to further the existing FGD operation another 10 years to

2029. Three i Design provided costs for upgrading and refurbishing the existing FGD system to extend the life through the 10-year period.

11.4.1.2 Replacement Scrubber Options at Brown

New replacement FGD technologies at A.B. Brown, identified in Table 10-1 have been evaluated for availability and applicability. Technically feasible options that are both available and applicable to A.B. Brown had high level AACE Class 5 installation cost estimates developed.

Table 10-1 Identify Available and Applicable Technologies

Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
Wet FGD		
Limestone Conversion of Existing Dual-Alkali FGD - Forced Oxidation (DA-LSFO)	Yes	No –Existing equipment capacity inadequate for conversion. New technology required to meet emissions criteria.
Limestone Conversion of Existing Dual-Alkali FGD - Inhibited Oxidation (DA-LSIO)	Yes	No –Existing equipment capacity inadequate for conversion. New technology required to meet emissions criteria.
Wet Limestone FGD - Forced Oxidation[(1)] (LSFO)	Yes	Yes – New installations are capable of meeting performance standards.
Wet Lime FGD - Inhibited Oxidation [(1)] (WLIO)	Yes	Yes– New installations are capable of meeting performance standards.
Spray Dryer Absorber (SDA)	Yes	No – SDA has limited SO_2 removal efficiency over the project range of fuels, which are higher sulfur contents.
Circulating Dry Scrubber (CDS) or Turbosorp	Yes	Yes – Installations comparable in size are in operation. However, no full-scale operational experience is available in the United States over the high sulfur range of the coals used at A.B. Brown.
Flash Dryer Absorber (FDA)	Yes	No – FDA has limited SO_2 removal efficiency over the high range of sulfur in the fuels.

Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
Ammonia Scrubber (NH_3)	Yes	Yes – However, only one small US industrial application in operation and current interest limited to one Chinese supplier with no US experience.
Powerspan ECO Process	No	No – Only pilot size experience

(1) Alternate absorber designs in wet lime or limestone FGD (spray tower, double contact spray tower, trays, etc.) are equal for comparison purposes.

Analysis was inclusive of FGD options necessary to keep the A.B. Brown Units 1 and 2 in compliance with current SO2 emissions limits and maintaining compliance with existing Hg and H2SO4 emissions requirements. Based on these requirements the DA-LSIO and DA-LSFO conversion options will not meet emissions performance criteria. High level capital installation estimates were developed by Black & Veatch for the Wet Lime FGD Inhibited Oxidation (WLIO), Circulating Dry Scrubber (CDS) and Ammonia Scrubber (NH3). Burns & McDonnell developed an estimate for the Wet Limestone FGD Forced Oxidation (LSFO), building on their previous experience with this technology assessment at A.B. Brown. Capital and O&M estimates for these remaining four technologies were evaluated by PACE Global screening using analysis consistent with the IRP evaluation Reference Case. The least cost option was selected and included in the BAU portfolio. Note that there are risks such as byproduct market availability, byproduct disposal requirements and reagent supply availability. These risks were qualitatively assessed independent of the screening analysis.

For the BAU to 2039 portfolio, an analysis of the most economic FGD scrubber option was conducted. Each of the four scrubber technologies was evaluated in the Aurora model with identical model runs except for the difference of the scrubber technology costs and performance metrics. The analysis demonstrated that the DA-LSIO was the least cost FGD scrubber technology among the four options. The DS-LSFO option was shown to increase portfolio costs by 1.51% all other things being equal, the NH3 option was shown to be 1.66% more costly and the CDS option was shown to be 2.95% more costly.

Accordingly, the DA-LSIO option was selected for modeling purposes in the BAU to 2039 portfolio.

11.4.1.3 Coal to Gas Conversion

The conversion of A.B. Brown Unit 1 and 2 existing coal fired boilers to burn natural gas instead of coal was studied. Conceptual design studies were developed by engineering firms and OEM suppliers 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 4 installation costs. The converted plant is expected to be operated as a peaking facility on 100% natural gas. Daily on/off cycling of the plant may be required. These units were originally designed as base load coal units. The boiler metallurgy and turbine were not designed for cycling operation. The impacts of cycling will require increased maintenance of this equipment compared to previous coal operations. Startup durations remain the same as coal fired operations continuing to limit the response time in a cycling environment. Natural gas conversion of the units reduces boiler efficiency compared to the coal fired design and increase net plant heat rate.

11.4.1.4 ACE Rule Compliance

The Affordable Clean Energy (ACE) rule, finalized by the United States Environmental Protection Agency (EPA) June 19, 2019, establishes new standards for reducing greenhouse gas emissions for coal fired electric utility generating units. ACE details specific heat rate improvement techniques, called Best System of Emission Reduction (BSER), that are 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 operations and maintenance (O&M) practices.

The 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. Applicability of candidate technologies for the four existing coal fired units is found in the "ACE Heat Rate Improvement Study" located in technical appendix 6.8. 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.

11.4.2 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	265	245
A.B. Brown 3	74	74
A.B. Brown 4	74	74
F.B. Culley 2	100	90
F.B. Culley 3	287	270
Warrick 4	162	150

11.4.3 New Construction Alternatives

Figure 11.36 – New Construction Alternatives

Technology	Fuel	Capacity (kW)
Biomass	Biomass	50,000
Energy Efficiency Bins 1-7 (2021-23)	Energy Efficiency	Varies
Energy Efficiency Bins 1-7 (2024-26)	Energy Efficiency	Varies
Energy Efficiency Bins 1-7 (2027-39)	Energy Efficiency	Varies
Hydroelectric	Hydro	50,000
Landfill Gas	Landfill Gas	4,500
F-Class CT	Natural Gas	236,635
E-Class CT	Natural Gas	84,721
GH-Class CT	Natural Gas	279,319
F-Class CCGT	Natural Gas	442,400
GH-Class CCGT	Natural Gas	510,700
Generic Solar PV	Solar	10,000
Generic Solar PV	Solar	50,000
Generic Solar PV	Solar	100,000
12to15 Year Solar PPA	Solar	112,500
20 Year Solar PPA	Solar	200,000
20 Year Solar PPA	Solar	165,460
25to30 Year Solar PPA	Solar	137,500
Li-Ion Battery Storage (4 hour)	Storage	10,000
Li-Ion Battery Storage (4 hour)	Storage	50,000
Flow Battery Storage (6 hour)	Storage	10,000
Flow Battery Storage (6 hour)	Storage	50,000
Flow Battery Storage (8 hour)	Storage	10,000
Flow Battery Storage (8 hour)	Storage	50,000
Li-Ion Battery Storage (paired with Generic Solar PV) (4 hour)	Storage	10,000
Li-Ion Battery Storage (paired with Generic Wind) (4 hour)	Storage	10,000
Annual MISO Capacity Market Purchase	Capacity	Up to 180,000
Li-Ion Battery Storage PPA (4 hour)	Storage	76,200
Solar PV (paired with Storage) PPA	Solar	133,333
Li-Ion Battery Storage (paired with Solar) PPA (4 hour)	Storage	42,000
Demand Response Bin 1 (2021-23)	Storage	Varies

Technology	Fuel	Capacity (kW)
Demand Response Bin 2 (2024-26)	Storage	Varies
Demand Response Bin 3 (2027-39)	Storage	Varies
Generic Wind	Wind	200,000
Generic Wind	Wind	50,000
12to15 Year Wind PPA	Wind	200,000
20 Year Wind PPA	Wind	300,000

11.5 RISK APPENDIX

Probabilistic modeling incorporates five key market variables and probability distributions into the analysis, allowing for the evaluation of a portfolio's performance over a wide range of future market conditions. Quantitative data are extracted from the results and is the foundation for the balanced scorecard. Probabilistic modeling begins with the development of 200 sets of future pathways for coal prices, natural gas prices, carbon prices, peak and average load (for Vectren, MISO Local Resource Zone 6 and all of MISO) and capital costs for a range of technologies. Each of these stochastic variables is propagated to the end of the study period, typically 1,000 to 3,000 times. A stratified sampling of the runs is taken, which allows the sample set to be reduced to 200 iterations. The 200 iterations of each stochastic variable are then inputted into the Aurora model. This allows for the testing of each candidate portfolio's performance across a wide range of market conditions.

All portfolios were subjected to each of the 200 iterations (scenarios) using the dispatch module in the Aurora model where the Vectren portfolios are fixed but other market participants can make decisions under each market scenario. The entire Eastern Interconnection except FRCC and ISO-NE was run stochastically in each scenario. The risk analysis (based on the probabilistic modeling) of each of the portfolios was developed by Pace Global using the Aurora 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. This was done by considering volatility of each factor in the short-term, medium-term and long-term.

- 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 inputs development.
- Each candidate portfolio was then run through simulated dispatch for the 200 possible future states using the Aurora production cost model. Aurora dispatches the candidate portfolio for each sampled hour over the planning horizon. For this risk analysis procedure, Aurora assumes that each candidate portfolio is constant but allows for builds and retirements to occur throughout the region based on economic criteria. Vectren generation, costs, emissions, revenues, etc. are tracked for each iteration over time.
- Next, values for each metric are tracked across all 200 iterations and presented as a distribution with a mean, standard deviation and other metrics as needed.
- These measures are used as the basis for evaluation in the risk analysis.

11.6 Stochastic Distributions

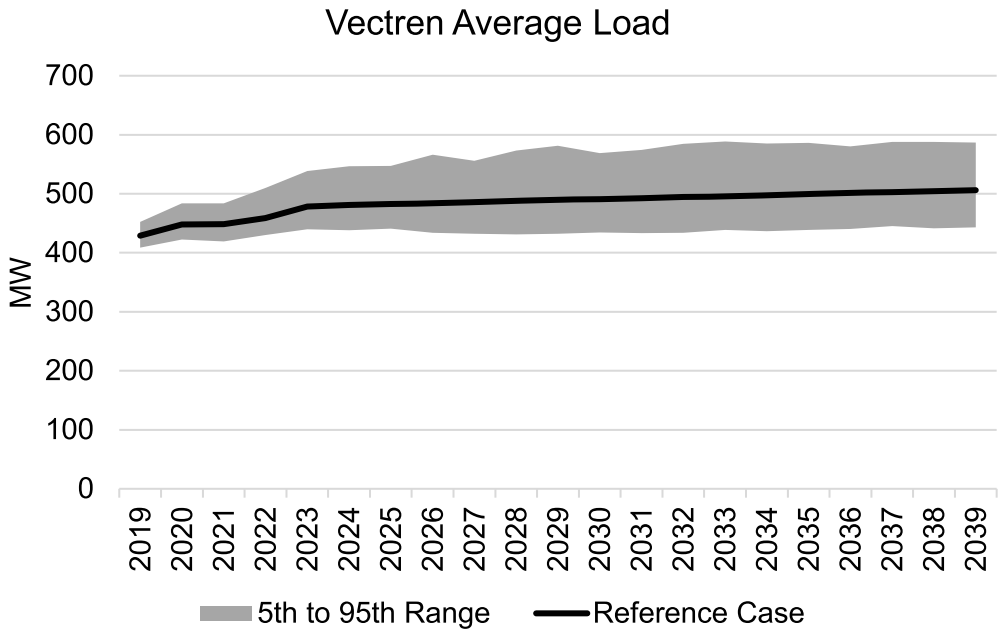
In order to perform the probabilistic modeling (stochastics), a set of probability distributions was required for each of the key market driver variables described above (fuel, emissions, load and capital costs). These probability distributions were developed from a simulation that creates 200 future paths for each stochastic variable. The following sections describe the methodologies for developing these stochastic variables.

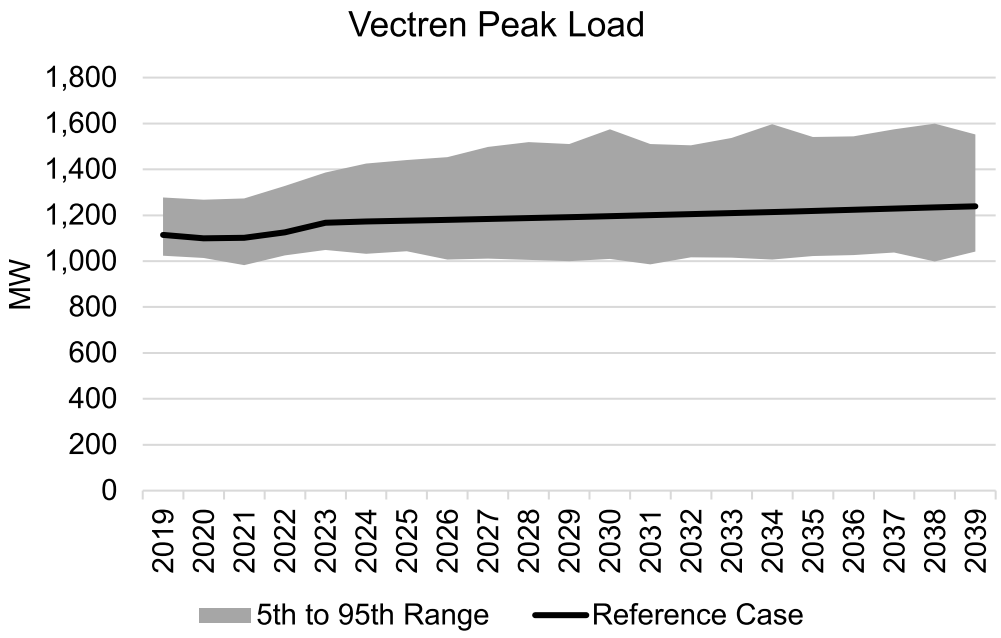
11.6.1 Load Stochastics

To account for electricity demand variability that derives from economic growth, weather, energy efficiency and demand side management measures, Pace Global developed stochastics around the average and peak load growth expectations for the Vectren control area and the neighboring ISO zones, including MISO, PJM and utilities not served by an ISO in SERC. Pace Global benchmarked the MISO-wide projections against MISO-sponsored load forecasting studies that are conducted by independent consultants,

institutions and market monitors and then released into the public domain. In addition, solar distributed generation (a decrement to Vectren load) and electric vehicles demand (an increment to Vectren load) were developed independently and incorporated into the Vectren load stochastics.

Exhibit 1: Vectren Load Distribution (Megawatts)



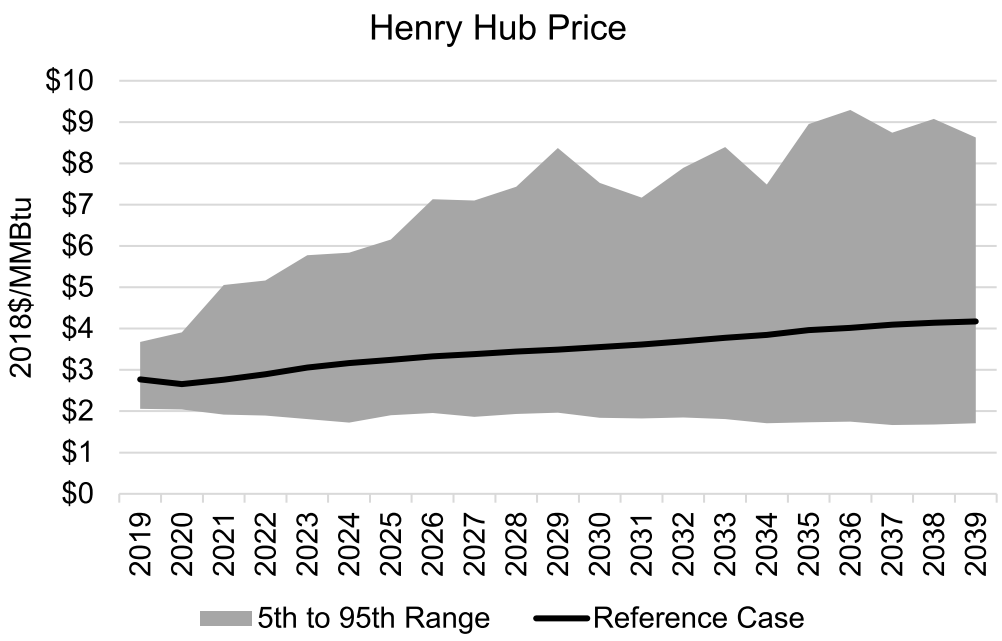


Source: Pace Global

11.6.2 Natural Gas Price Stochastics

Pace Global developed natural gas price stochastic distributions for the benchmark Henry Hub market point. These stochastic distributions are first based on the consensus Reference Case view of natural gas prices with probability bands developed then based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility. For the period 2019-2022, volatility calculated from the past three years of price data is used. For 2023-2025, volatility calculated from the past five years is used. For 2026-2039, volatility calculated from the past 10 years is used. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95th percentile probability bands are driven by increased gas demand (e.g., coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization relatively low as well as few to no new environmental regulation around power plant emissions.

Exhibit 2: Natural Gas (Henry Hub) Price Distribution (2018$/MMBtu)

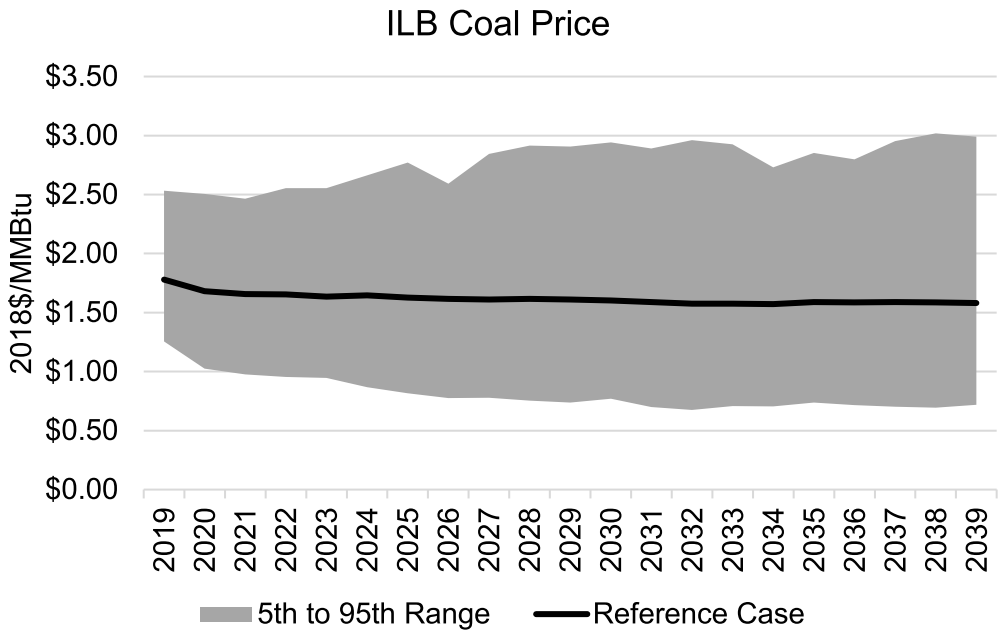


Source: Pace Global

11.6.3 Coal Price Stochastics

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

Exhibit 3: Coal Price Distribution (2018$/MMBtu)



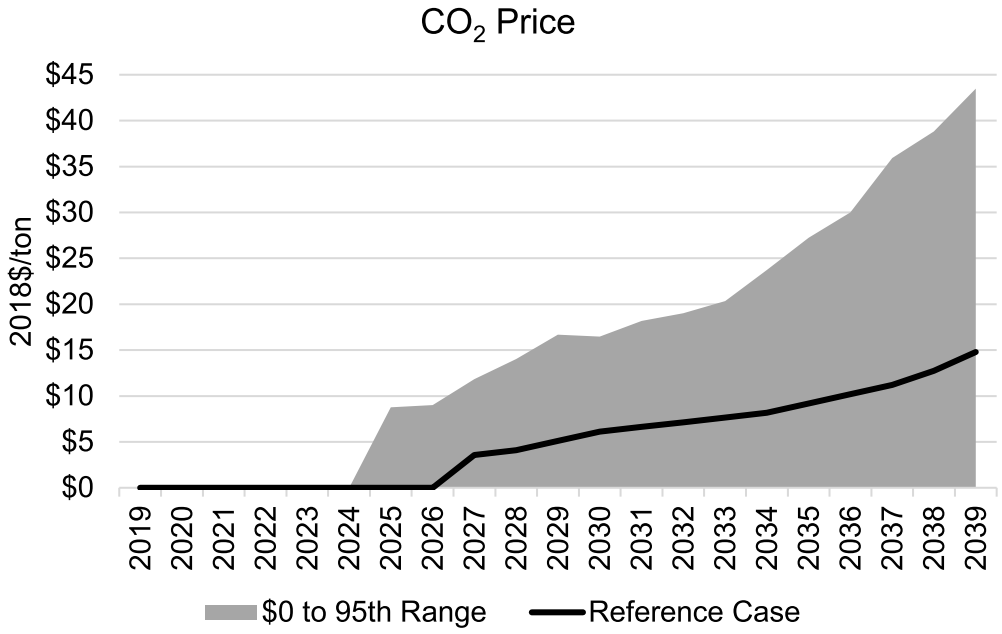
Source: Pace Global

11.6.4 CO_2 Emissions Price Stochastics

Pace Global developed uncertainty distributions around carbon compliance costs, which were used in Aurora to capture the inherent risk associated with regulatory compliance requirements. The technique to develop carbon costs distributions, unlike the previous variables, is based on projections largely derived from expert judgment, as there are no

national historical data sets (only regional markets in California and the northeast U.S.) to estimate the parameters for developing carbon costs distributions. The consensus Reference Case CO_2 price outlook reflects a view that some type of legislation will likely occur in the mid-2020s to provide incentives for faster shifts from fossil to renewable generation. Previous studies of a proposed trading mechanism showed prices rising to about $15/ton. The bottom end of the distribution assumes no future regulation. The top end reflects the social cost of a carbon emission program. Two portfolios (HB 763 and High Regulatory) were optimized using CO_2 prices that exceeded the 95th percentile shown below.

Exhibit 4: CO_2 Price Distribution (2018$/ton)



Source: Pace Global

11.6.5 Capital Cost Stochastics

Pace Global developed the uncertainty distributions for the cost of new entry units by technology type, which was used in Aurora for determining the economic new builds based on market signals. These technologies included gas peaking units, gas combined

cycles units, solar, wind and battery storage resources. The methodology of developing the capital cost distributions is a two-step process: (1) a parametric distribution based on a consensus Reference Case view of future all-in capital costs, historical costs and volatilities and a sampling of results to develop probability bands around the consensus Reference Case; and (2) a quantum distribution that captures the additional uncertainty with each technology that factors in learning curve effects, improvements in technology over time and other uncertain events such as leaps in technological innovation.

Exhibit 5: Solar Capital Costs Distribution (2018$/kW)

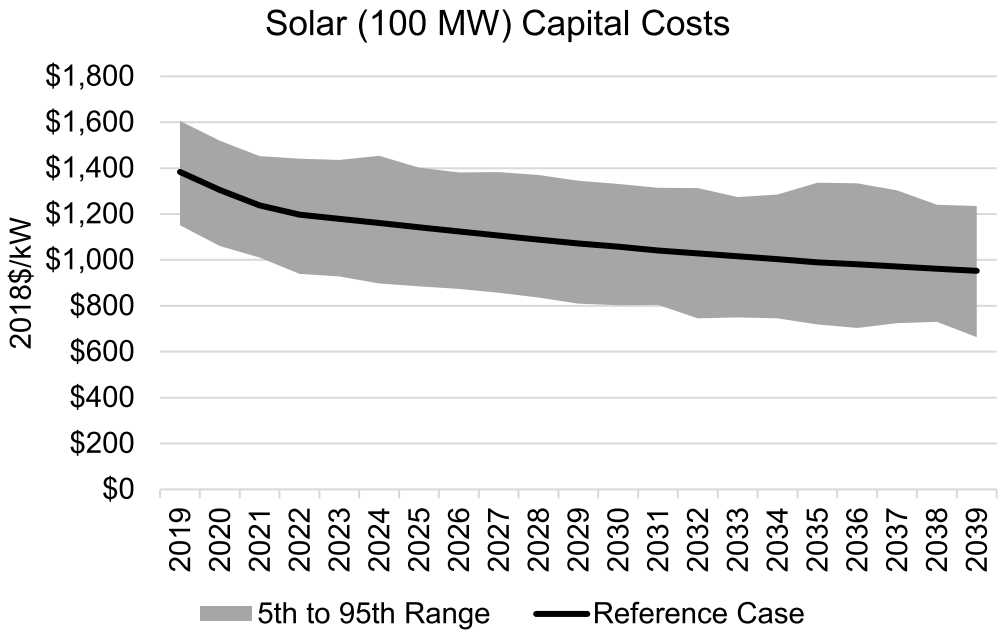
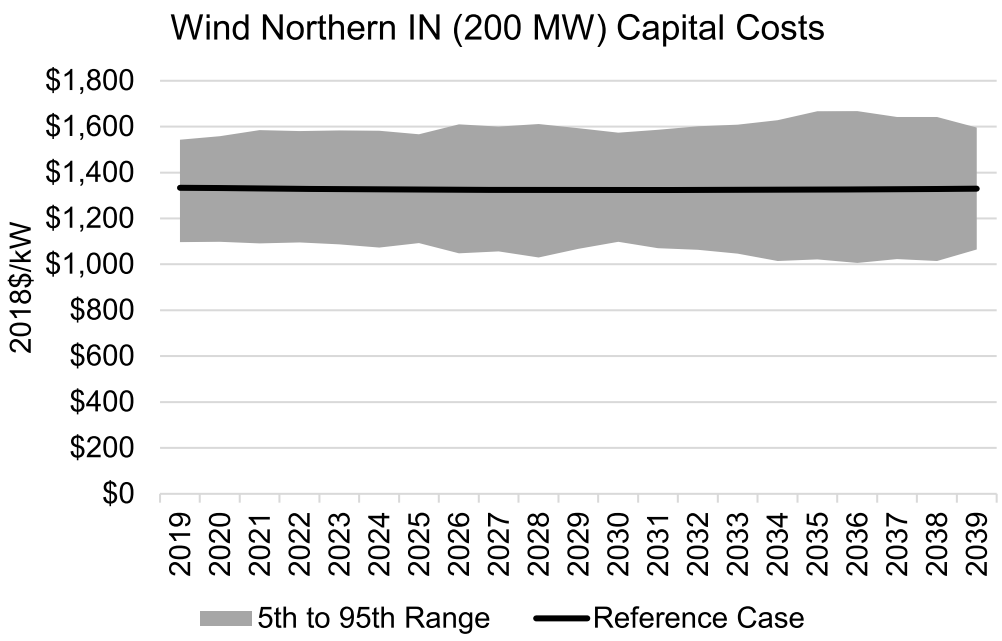


Exhibit 6: Wind Capital Costs Distribution (2018$/kW)



Source: Pace Global

Exhibit 7: Battery Storage Capital Costs Distribution (2018$/kW)

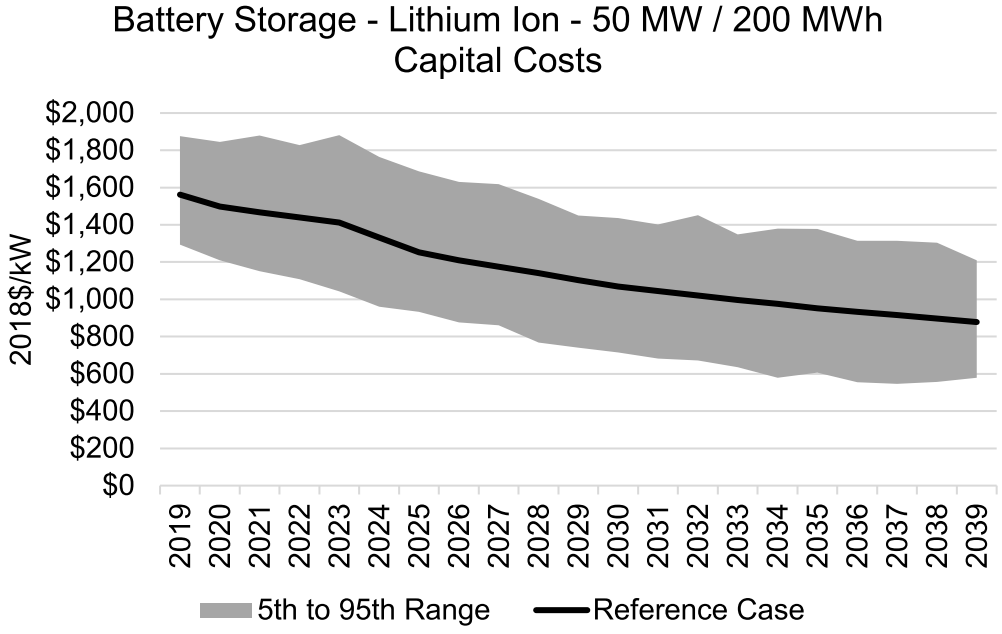
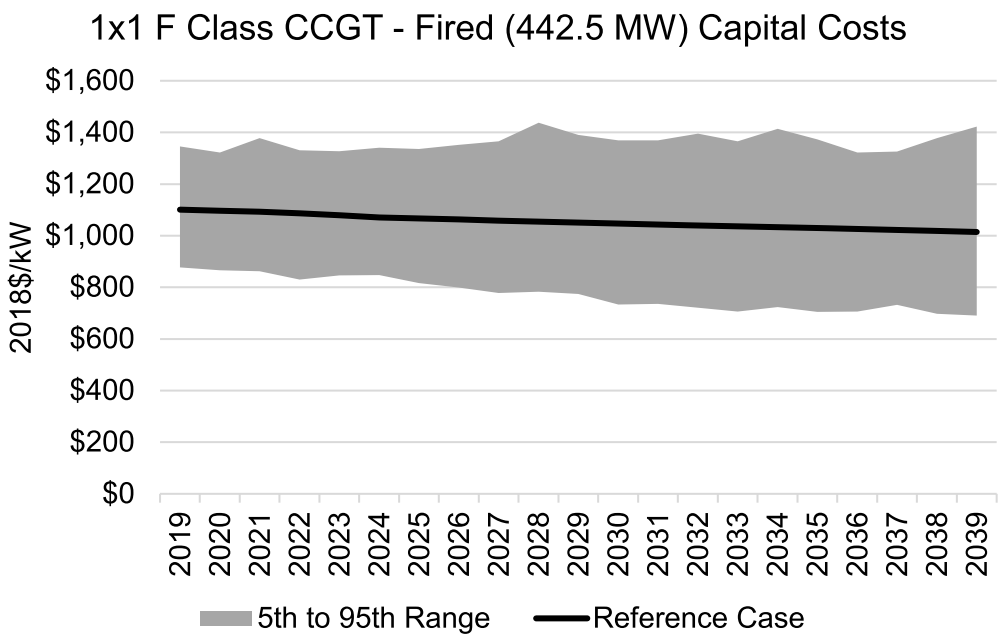
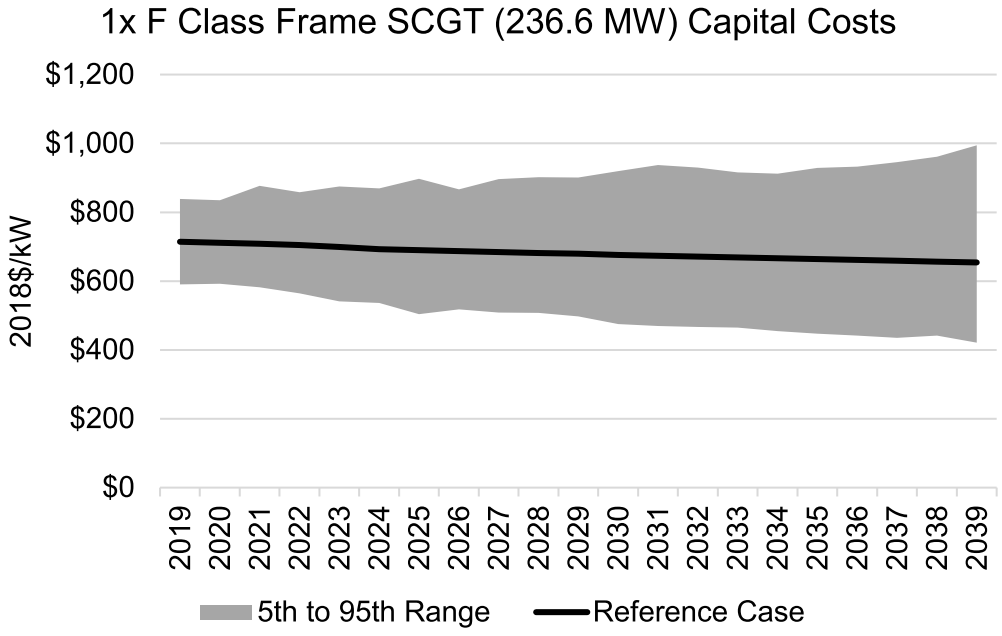


Exhibit 8: Advanced Combined Cycle Capital Costs Distribution (2018$/kW)



Source: Pace Global

Exhibit 9: Advanced Combustion Turbine Capital Costs Distribution (2018$/kW)



Source: Pace Global

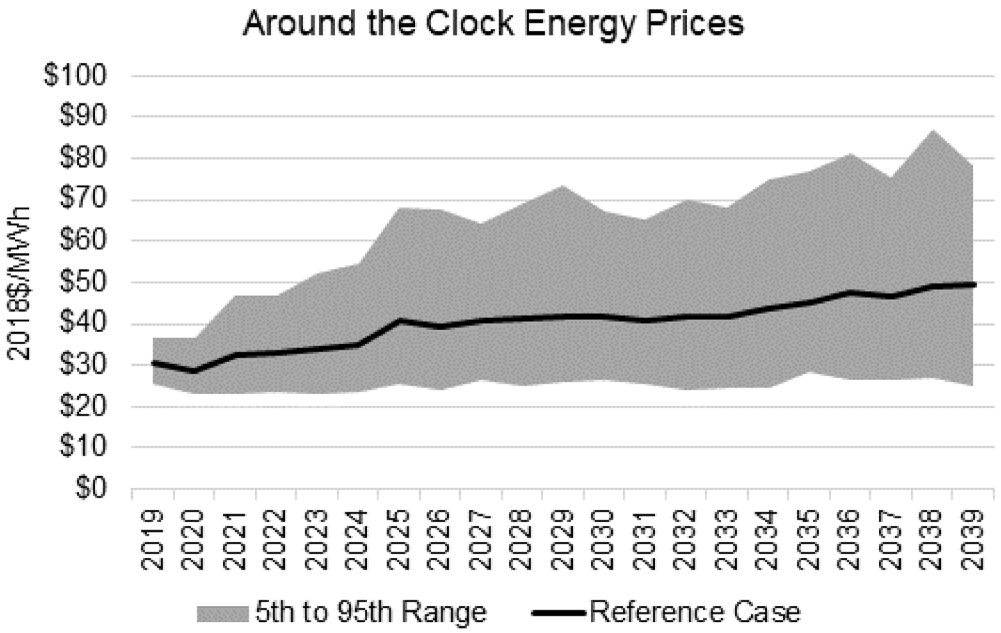
11.6.6 Cross-Commodity Stochastics

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

11.6.7 Energy Price Distribution

Pace Global produces a stochastic distribution of energy prices as a result of running the input distributions through Aurora (200 times). Aurora not only determines the build decisions for the region but also the resulting prices. The exhibit below displays these prices.

Exhibit 1: Stochastic Inputs – Energy Prices – Market Forecast



11.6.8 Affordability Ranking

Figure 11.37 – Probabilistic 20-Year Mean NPV $ Billion

Portfolio	20 Year NPV[49]	% above lowest cost
Renewables + Flexible Gas	$2,526	99.6%
Reference Case	$2,536	100.0%
High Technology (Preferred Portfolio)	$2,590	102.2%
All Renewables by 2030	$2,613	103.0%
Bridge ABB1 Conversion	$2,675	105.5%
Diverse Small CCGT	$2,680	105.7%
Business as Usual to 2029	$2,689	106.0%
ABB1+ABB2 Conversions	$2,834	111.8%
ABB1 Conversion + CCGT	$2,872	113.3%
Business as Usual to 2039	$2,912	114.8%

[49] The NPV of energy procurement is an indicative component of rates

11.7 TRANSMISSION APPENDIX

11.7.1 Transmission and Distribution Planning Criteria

Vectren continually assesses the performance of its electric transmission and distribution systems to ensure safe and reliable service for its customers. The primary goals of Vectren'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 Vectren 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;
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 Midcontinent Independent System Operator (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 Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC) and RF Reliability Standards for transmission planning.

11.7.2 MISO Regional Transmission Planning

The Midcontinent Independent System Operator (MISO) performs the North American Electric Reliability Corporation (NERC) functional role of Planning Coordinator on behalf of Vectren. In its NERC functional role of Transmission Planner, Vectren 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. Vectren is responsible for submitting the required modeling data to MISO pursuant to NERC MOD-032.

Vectren participates in MISO coordinated seasonal transmission assessments (CSAs) 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. Vectren also participates in MISO Generator Interconnection and Transmission Service Requests planning processes as required.

Vectren 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 Vectren's Duff substation and Big Rivers Electric Corporation's Coleman EHV substation during the MTEP 2015 planning cycle. The project is expected to be in-service by the beginning of 2021. Pursuant to FERC Order 1000, MISO solicited competitive bids to construct the 345kV line. Vectren partnered with PSEG in submitting a proposal to MISO to construct the line; however, the project was awarded to Republic Transmission, LLC. Vectren, as the incumbent transmission owner, will be responsible for the Duff substation modifications required for the project. The overall project cost is shared according to MISO's Tariff. The project not only provides regional economic benefits, but also enhances grid reliability in the area of Vectren's Newtonville substation.

11.7.3 Annual Transmission Assessment

Vectren'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 Vectren 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.

Vectren'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 Vectren Bulk Electrical System (100kV and above) is expected to be stable and perform well over the next 10 years. 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, Vectren plans projects to mitigate the violations.

The loss of the two 138kV lines into Toyota substation results in the loss of service to the facility. A new 138kV line from Toyota substation to Scott Township substation is proposed. This line will also provide a second line into Scott Township substation, which is on a radial 138kV line. Scott Township substation provides voltage support for most of the load along the Highway 41 North corridor. This proposed line will also become a parallel path to the Francisco to Elliott 138kV line and increases post-contingent import capability.

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 Vectren 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 are proposed as alternate feeds to reduce outage times.

- A new 69kV line to be installed between Boonville and Boonville Pioneer Substation (scheduled in-service date of 12/31/2021).

- Extend an existing 69kV line to provide a third source into the Jasper area from Dubois substation (scheduled in-service date of 12/31/2024).

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.

Toyota South and Tepe Park are new distribution substations recently installed to meet load growth. The Tepe Park substation project also facilitates 4kV to 12kV conversion projects.

SECTION 12
TECHNICAL APPENDIX ATTACHMENTS

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Attachment 4.3 2019 MISO LOLE Study Report

Attachment 6.1 Vectren Electric 2018-2020 DSM Plan

Attachment 6.2 2019 DSM Market Potential Study

Attachment 6.3 All-Source RFP

Confidential Attachment 6.4 1x1 CCGT Study

Attachment 6.5 Coal to Gas Conversion Study

Attachment 6.6 Brown Scrubber Assessment Study

Attachment 6.7 Environmental Compliance Options Study

Attachment 6.8 ACE Rule Heat Rate Study

Attachment 8.1 Balance of Loads and Resources

Attachment 8.2 Confidential Aurora Input Model Files

Attachment 8.3 Aurora Output Model Files (submitted via DVD)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 116
CenterPoint 2023 IRP

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.

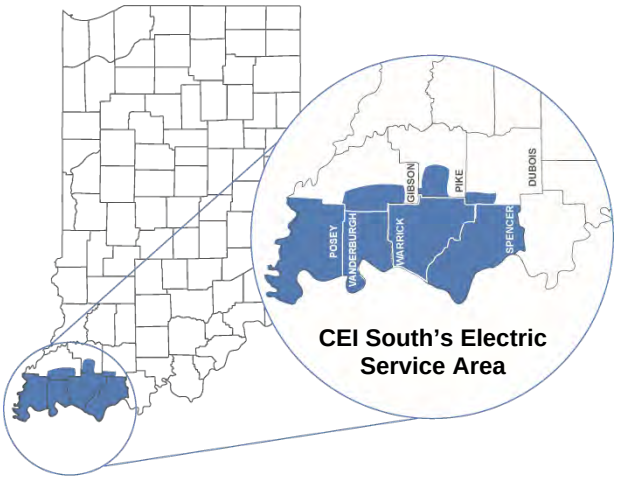
The preferred portfolio also provides several off-ramps (future transitional inflection points) should they be needed. 1) CEI South plans to discontinue joint operations of Warrick 4 ("W4") at the end of 2023 but continues to speak with Alcoa about a possible extension into 2025. This option could shield 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 ("$H2S0_4$") except F.B. Culley 2.
[2] Joint operations agreement expires 12/31/23

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

III. Integrated Resource Plan

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

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

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

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

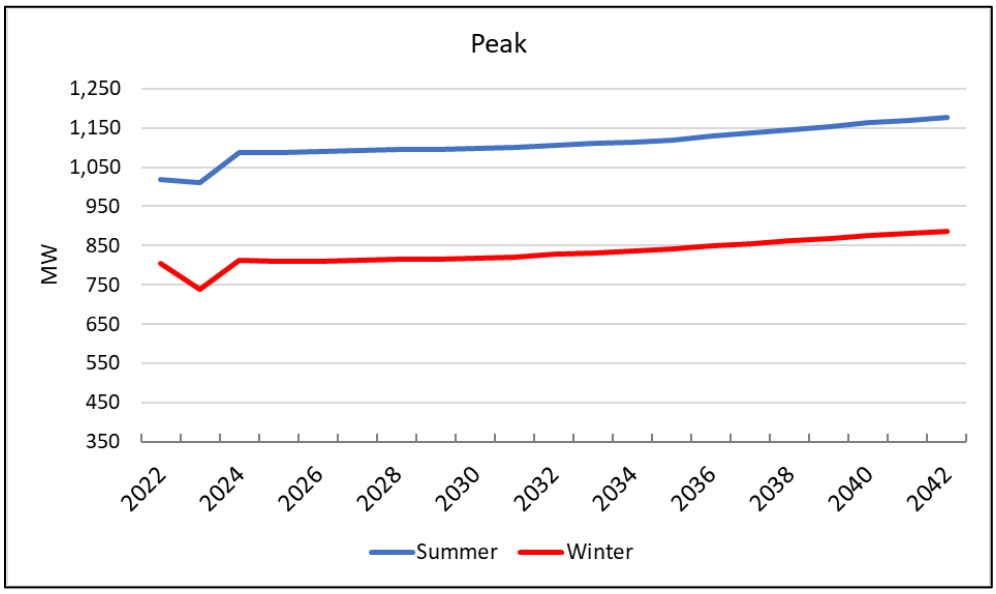
A. Customer Energy Needs

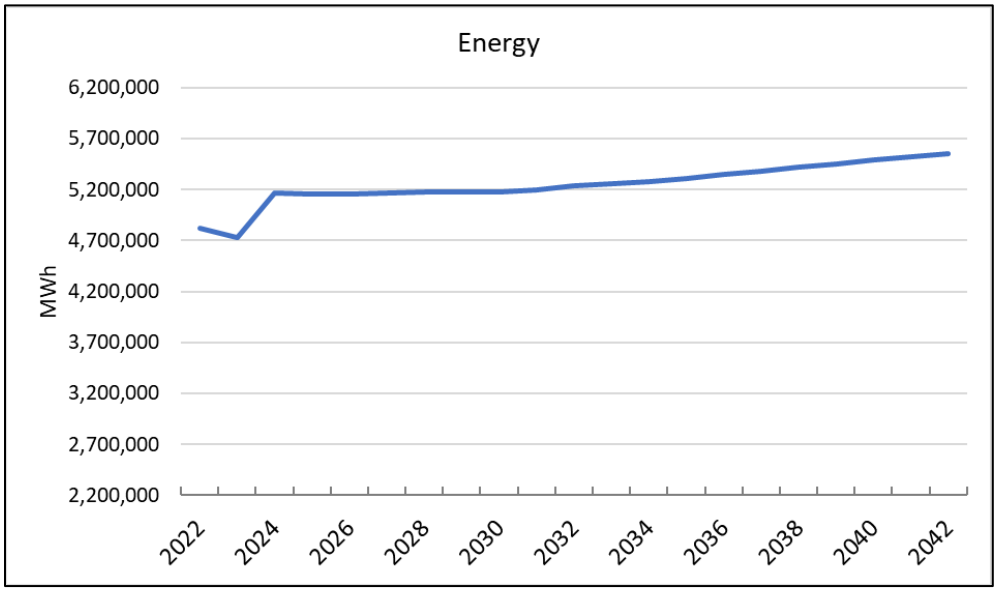
The IRP begins by evaluating customers' need for electricity over the 20-year planning horizon. CEI South worked with Itron, Inc., a leader in the energy forecasting industry, to develop a forecast of customer energy and demand requirements. Demand is the amount of power being consumed by customers at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

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

approved seasonal construct beginning in the 2023/2024 planning year on June 1, 2023. Later in this document it is further explained how MISO continues evaluating measures to help ensure year-round reliability, beyond the seasonal construct.

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





B. Resource Options

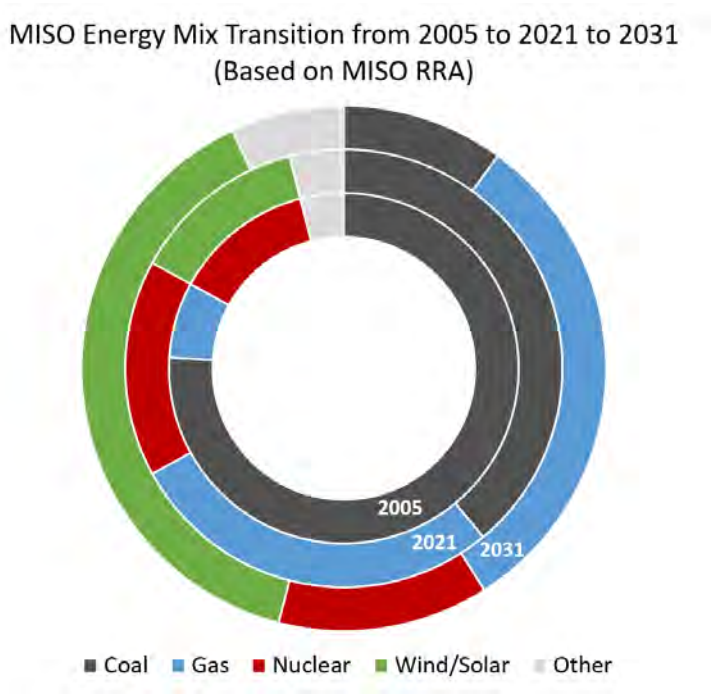
The next step in an IRP is identifying resource options to satisfy customers' anticipated need. Many resources were evaluated to meet customer energy needs over the next 20 years. CEI South considered both new and existing resource options. 1898 & Co., a well-respected engineering firm, conducted an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

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

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

i. Industry Transition

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



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

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

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

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

ii. Changing Market Rules to Help Ensure Reliability

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

include challenges to the ability to maintain acceptable voltage and thermal limits on the grid.

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

iii. Battery Storage and Transmission Resources

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

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

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

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

C. Uncertainty/Risk

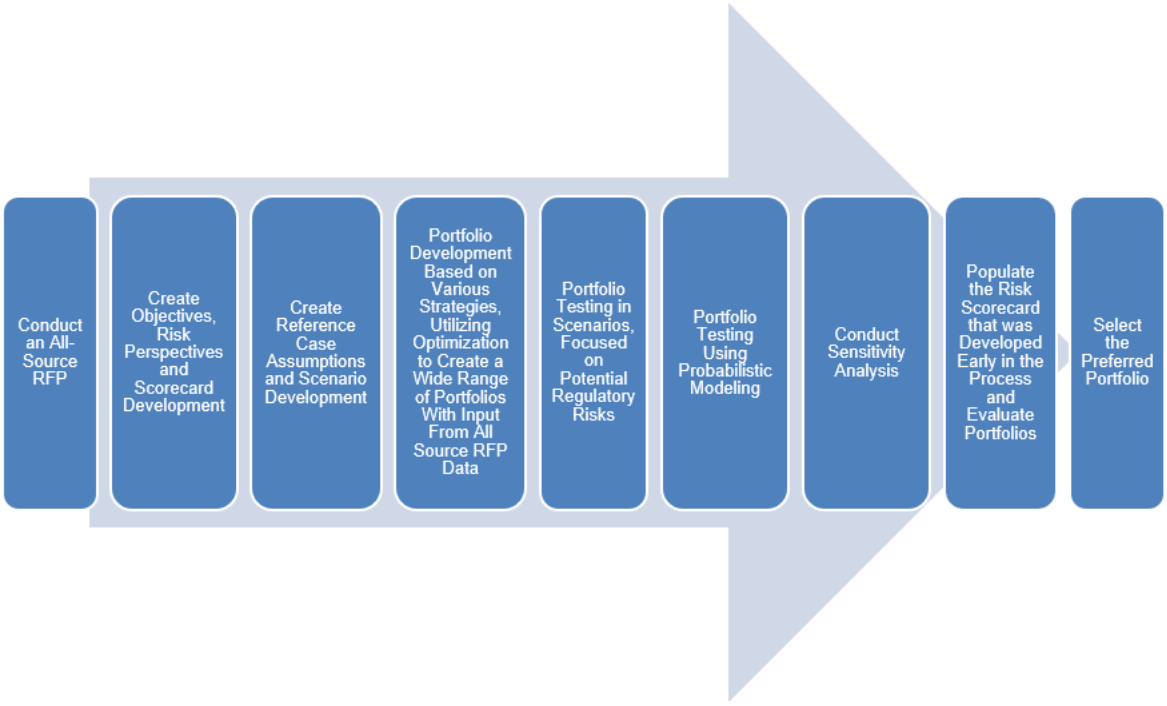
The future is far from certain. Uncertainty creates a risk that a generation portfolio that is reasonable under an anticipated future fails to perform as expected if the future turns out differently. CEI South's IRP analysis was developed to identify the best resource mix of generation and energy efficiency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

IV. Analysis

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

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

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



V. Stakeholder Process

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

As in the last IRP, each of the first three stakeholder meetings began with stakeholder feedback. CEI South would review requests/comments since the last stakeholder meeting and provide feedback. Suggestions were taken, and in instances where suggestions were

not acted upon, CEI South made a point to further discuss and explain why not. Notes for each meeting were included in question and answer format, summarizing the conversations. Additionally, feedback was received, and questions were answered via e-mail (irp@centerpointenergy.com) and with one off phone calls/meetings in between each public stakeholder meeting by request, in addition to tech-to-tech meetings mentioned above.

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

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

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

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

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

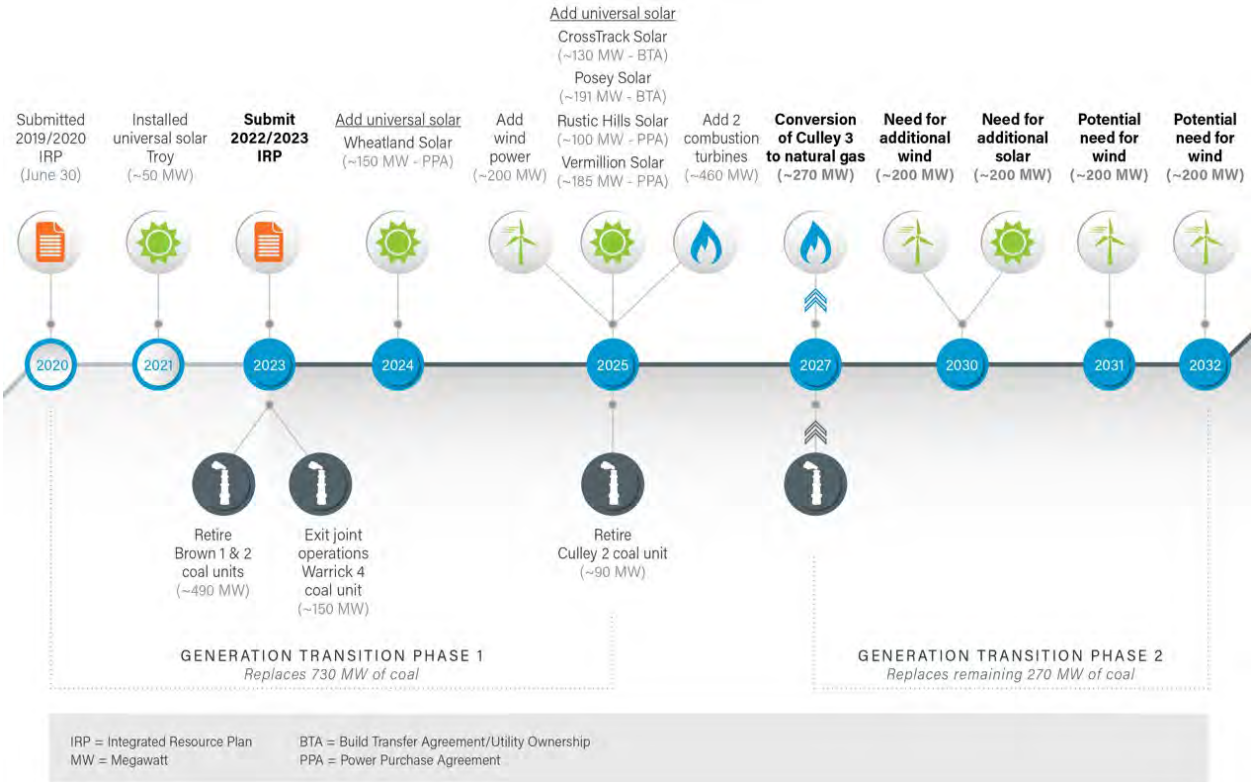
Request	Response
Incorporate more than proposed 10-20 MWs of Industrial DR	CEI South included 25 MWs of industrial DR as a resource. Currently, CEI South does not have any industrial DR registered with MISO. CEI South is engaged in conversations with a demand response aggregator to capture the potential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

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

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

VI. The Preferred Portfolio

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

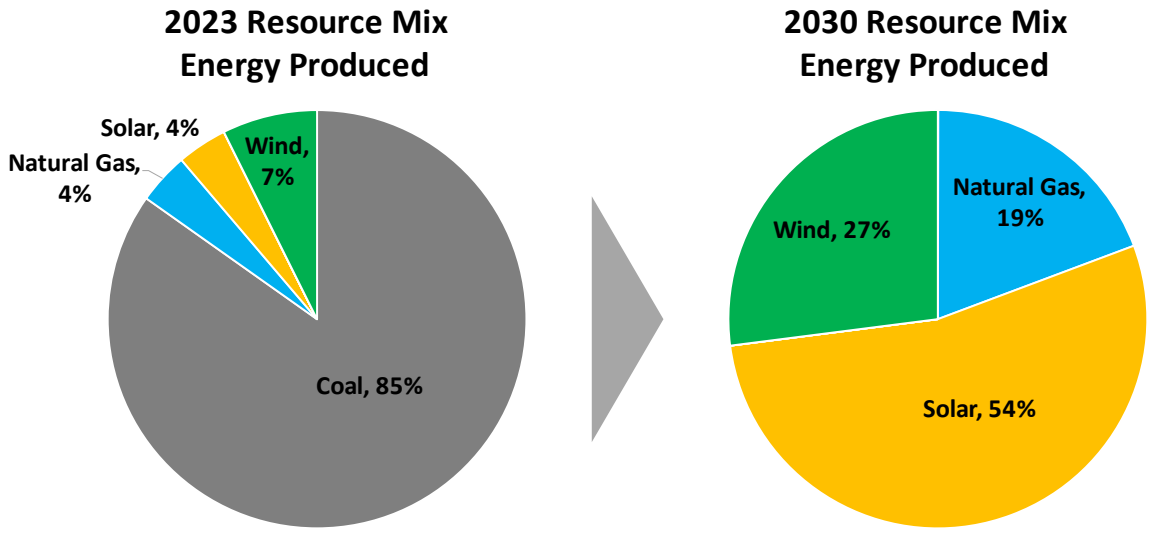


This preferred portfolio:

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

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

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



VII. Next Steps

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

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

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

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

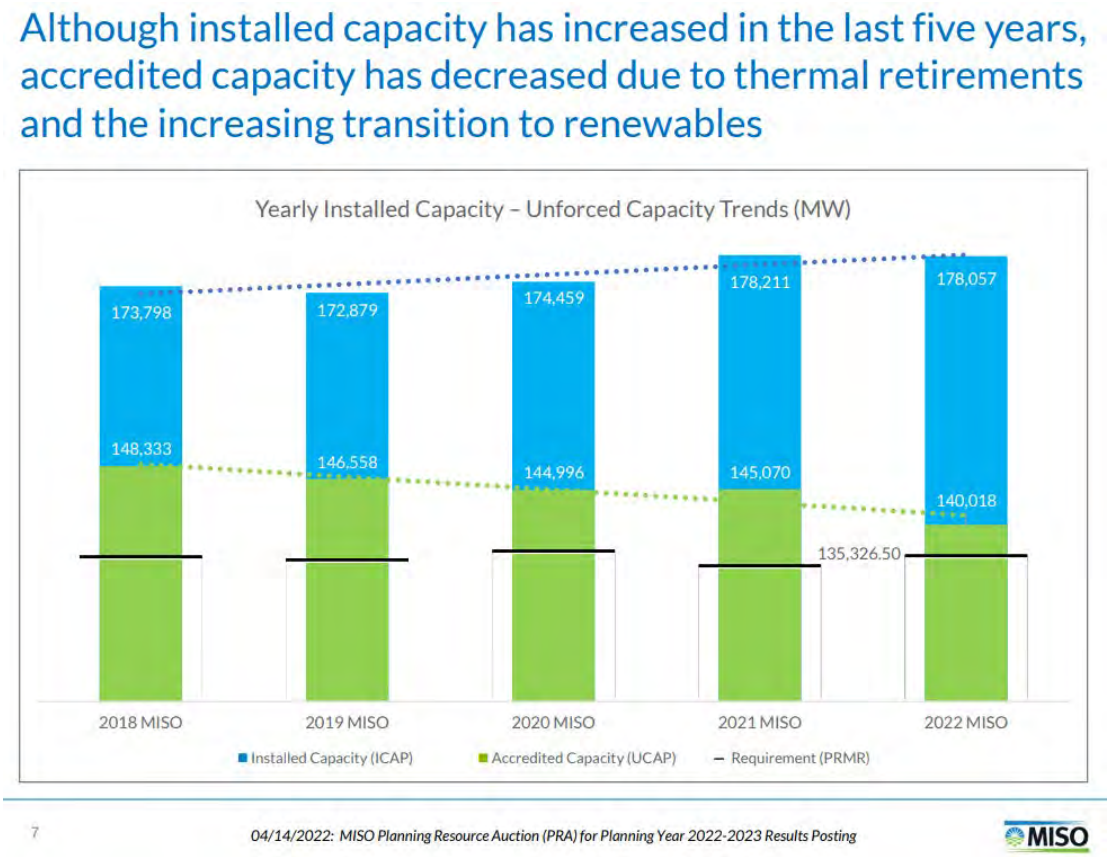
FERC Order No. 2222 instructs Regional Transmission Operators ("RTO") and Independent System Operators ("ISO"), like MISO, to allow for Distributed Energy Resource ("DER") aggregations to participate directly in the wholesale markets and establish a new category of market participants. A DER is considered 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.

[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 guidence 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-

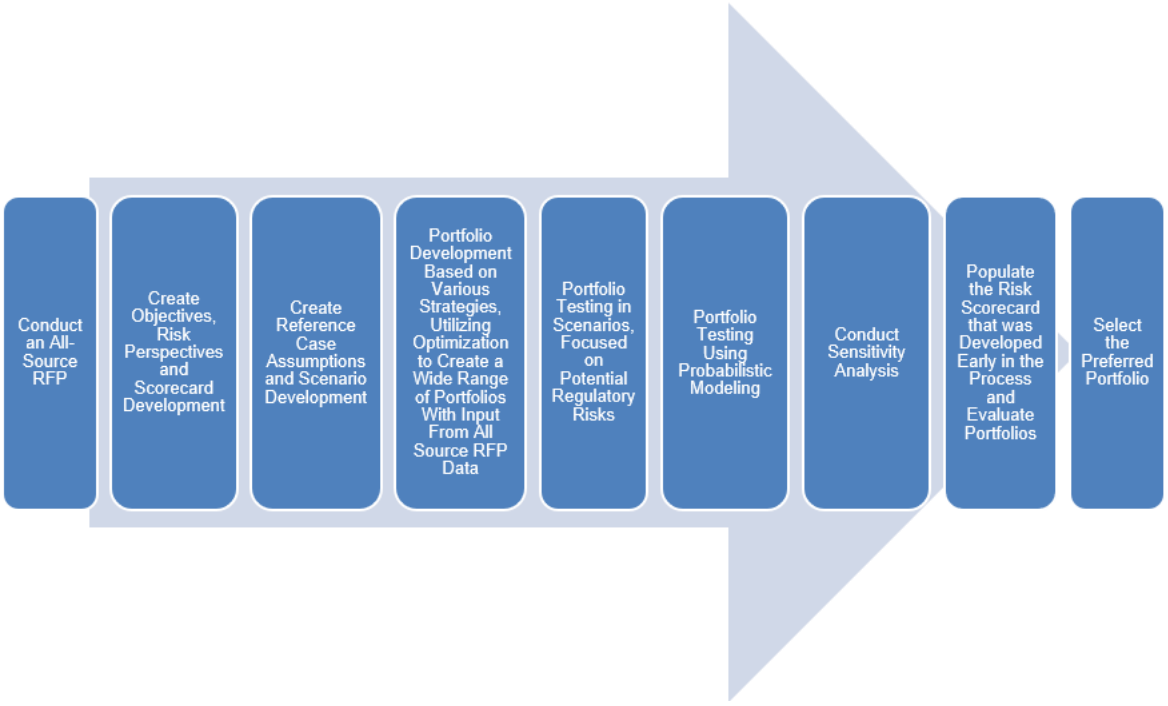
Source RFP was structured to be open and non-limiting and resulted in proposals largely comprised of solar, wind, battery storage, and Load Modifying Resource ("LMR")/DR resources. The All-Source RFP is discussed in further detail in sections 3 and 6 of this report.

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

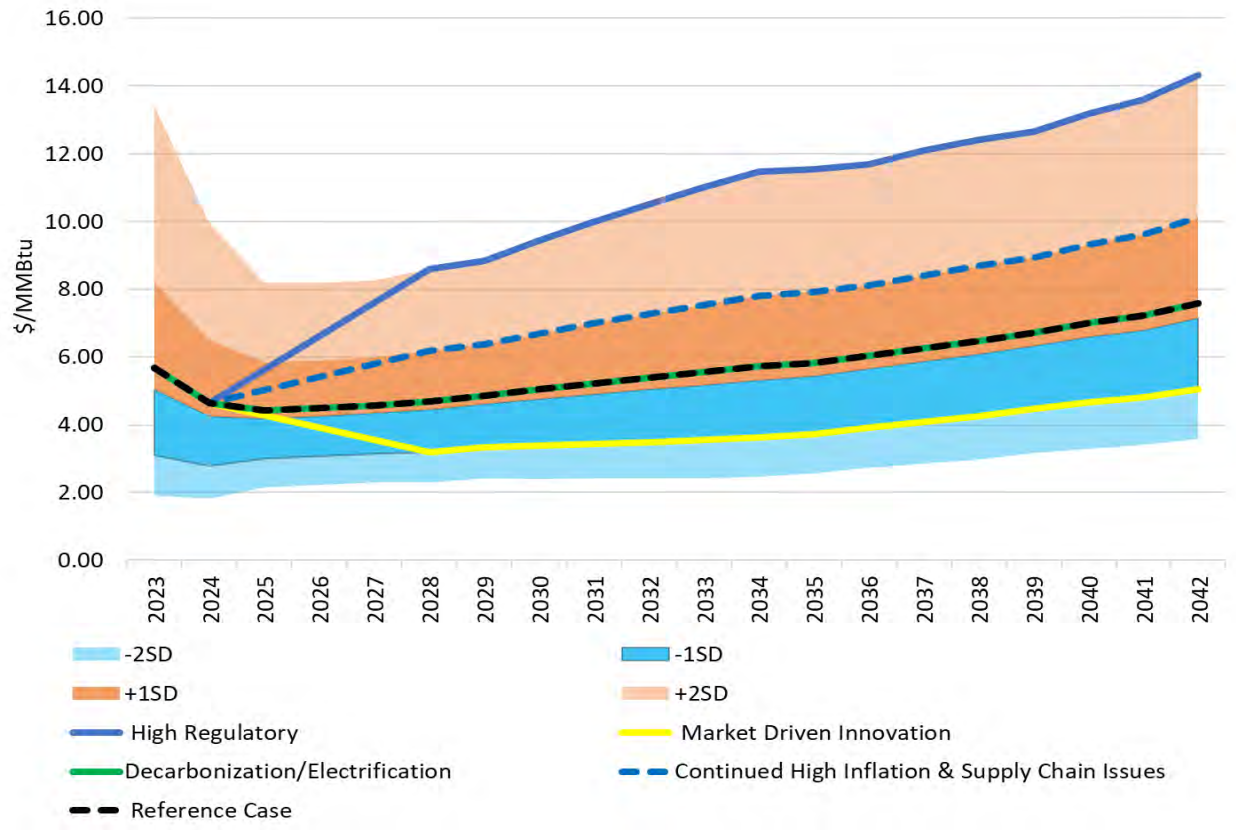
	CO_2	Gas Regulation	Other Environmental Regulations	Economy	Load	Natural Gas Price	Coal Price	Renewables and Storage Cost	EE Cost[19]
Reference Case	ACE Proxy	None	None	Base	Base	Base	Base	Base	Base
High Regulatory	Highest	Fracking Ban	MATS Update	Lower	Lower	Highest (+2 SD)	Higher	Lower	Higher
Market 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.

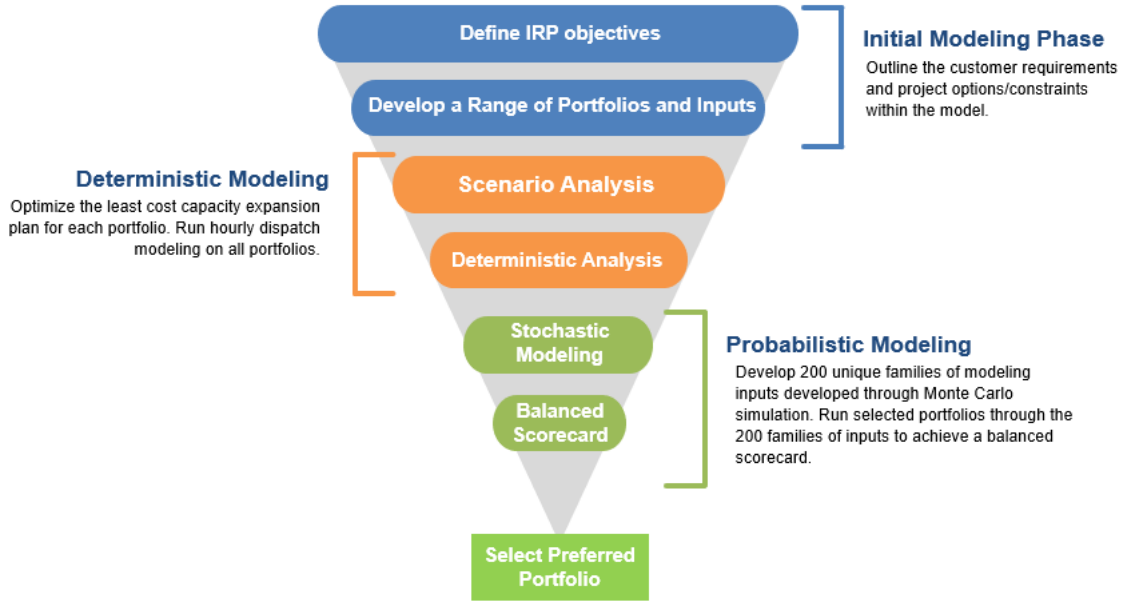
Portfolios were developed utilizing EnCompass modeling for the Reference Case, the alternate scenarios, and additional portfolios developed based on stakeholder feedback. The model uses hourly chronological dispatch over a 20-year period, which means

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

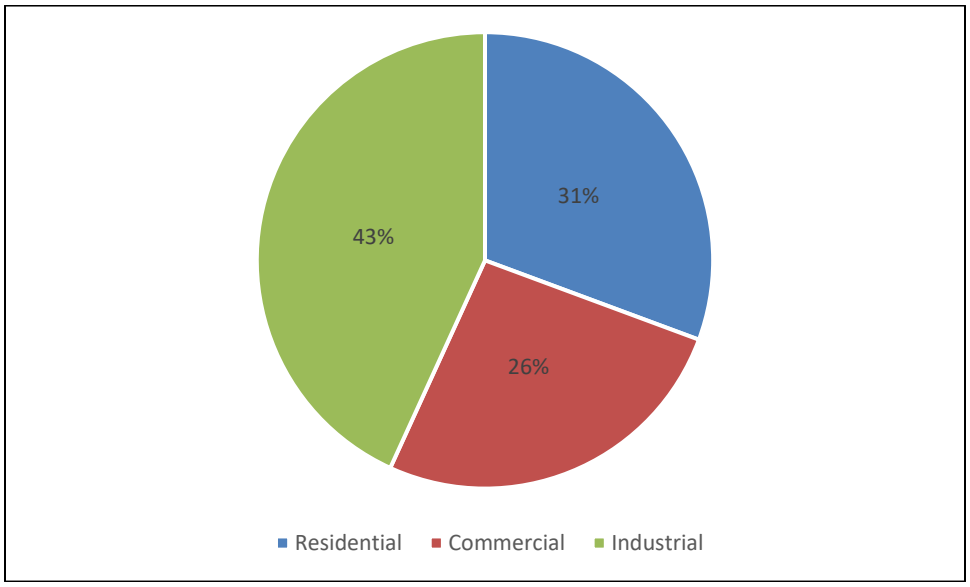
During the public stakeholder process CEI South received seven informal data requests from the CAC and Sierra Club. These data requests and CEI South's response can be found in the technical appendix 3.

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.

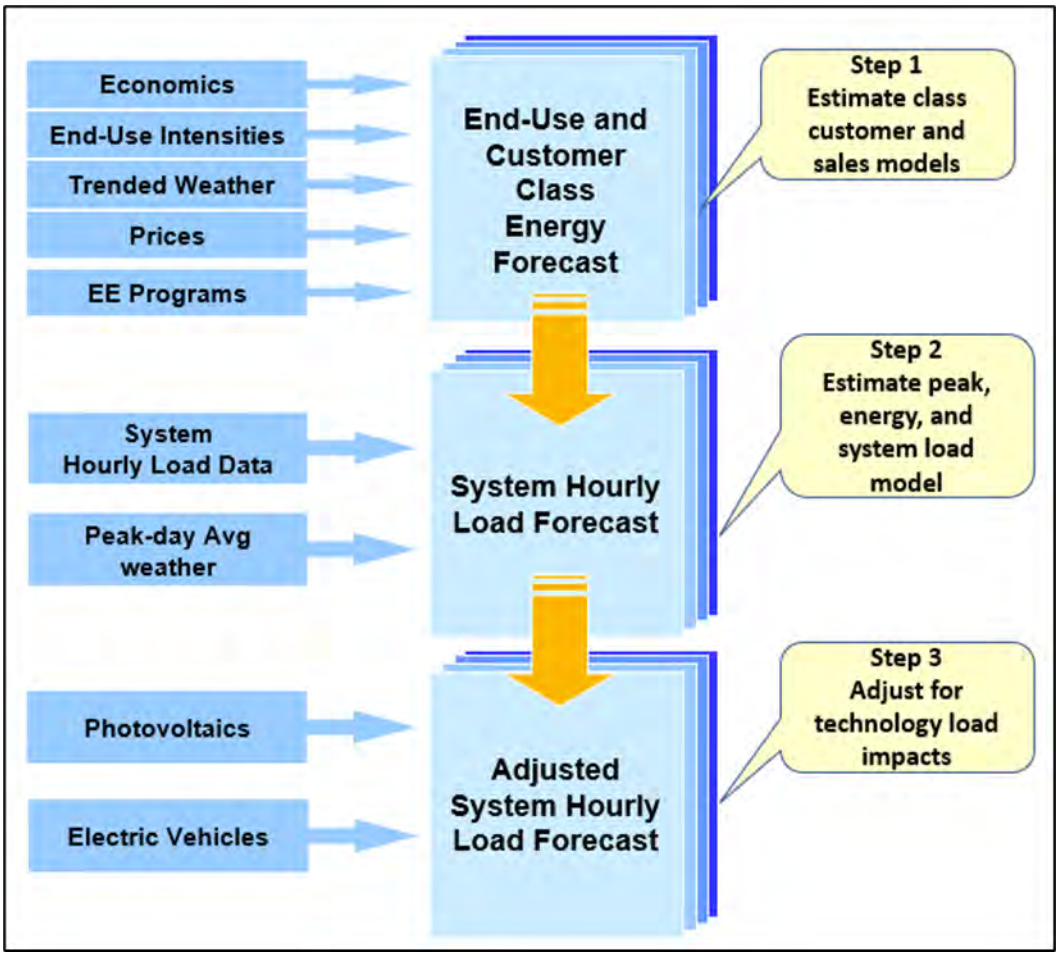
Weather is also a driver of electric consumption. CEI South's peak demand is typically in summer when temperatures are hottest. Air conditioning drives summer usage. Itron used a trended weather assumption for the normal weather in the sales and demand forecast in order to capture recent weather activity. 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.

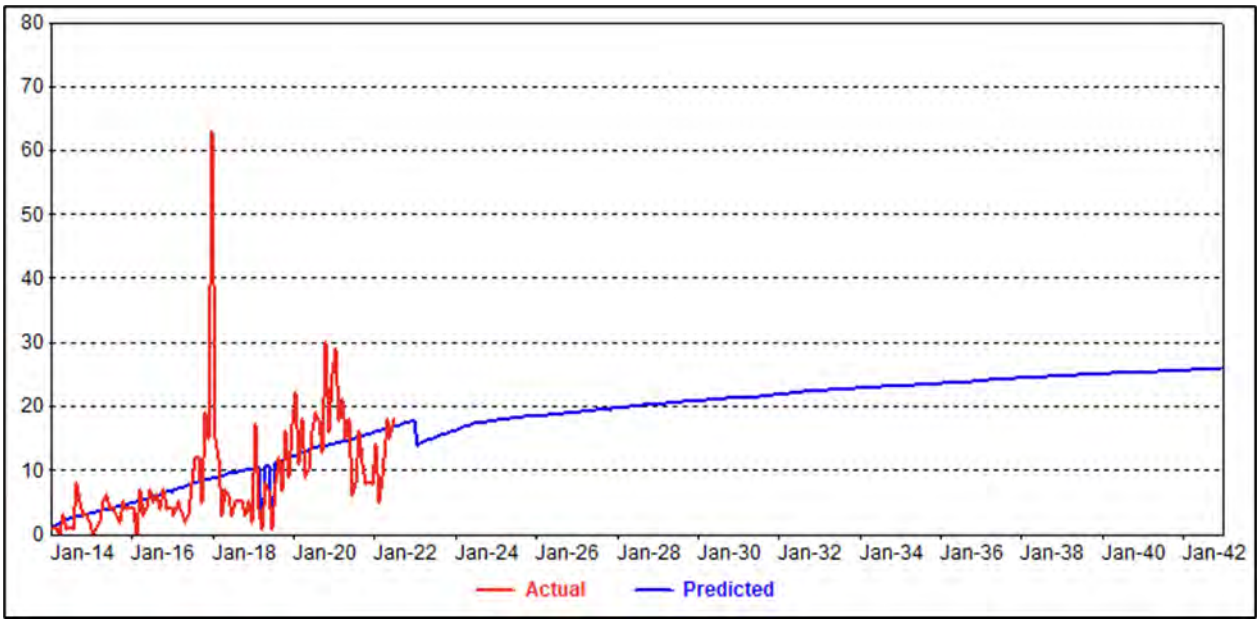
The primary factor driving system adoption is a customer's return-on-investment. Itron created a simple payback model, which was used as proxy. Simple payback reflects the length of time needed to recover the cost of installing a solar system - the shorter the payback, the higher the system adoption 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

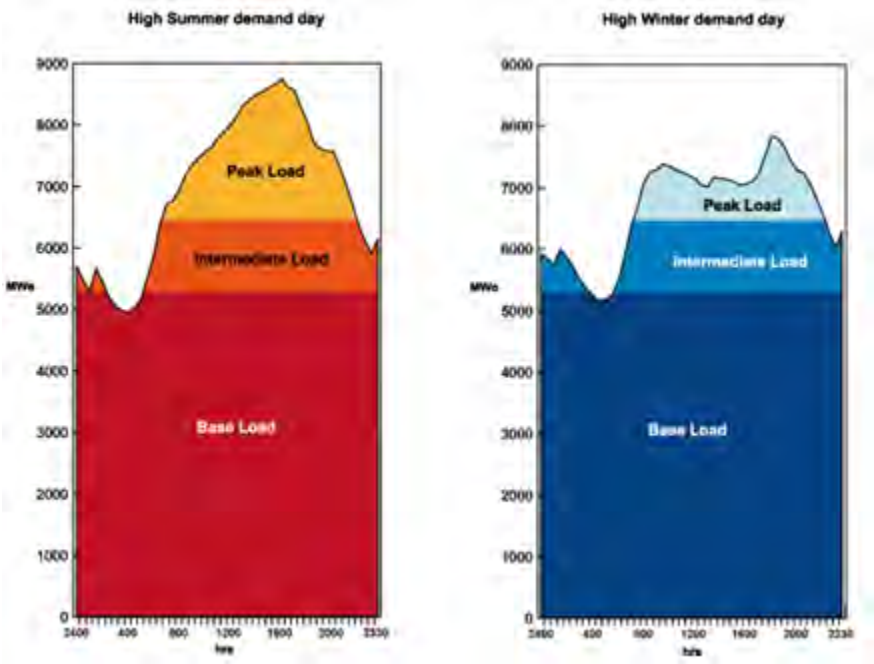
There are three levels of electric load: base load, intermediate load and peak load. Base load is the minimum level of demand on an electrical supply system over 24 hours. Base load is primarily served by power plants which can generate consistent and dependable power. Intermediate load is a medium level 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

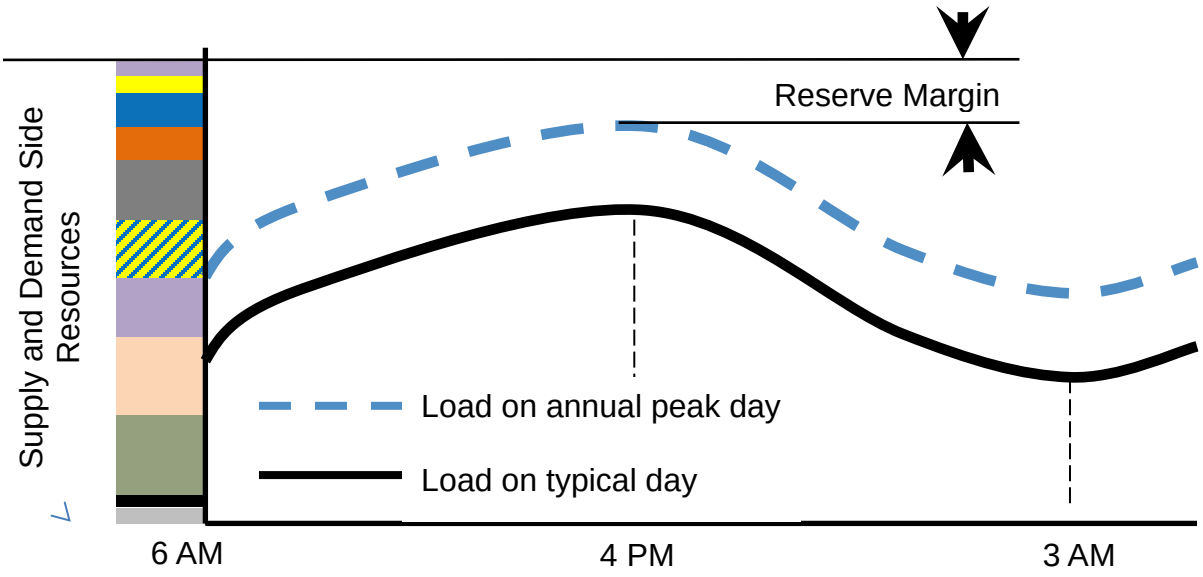


Figure 5-3 – Historic MISO PRMR

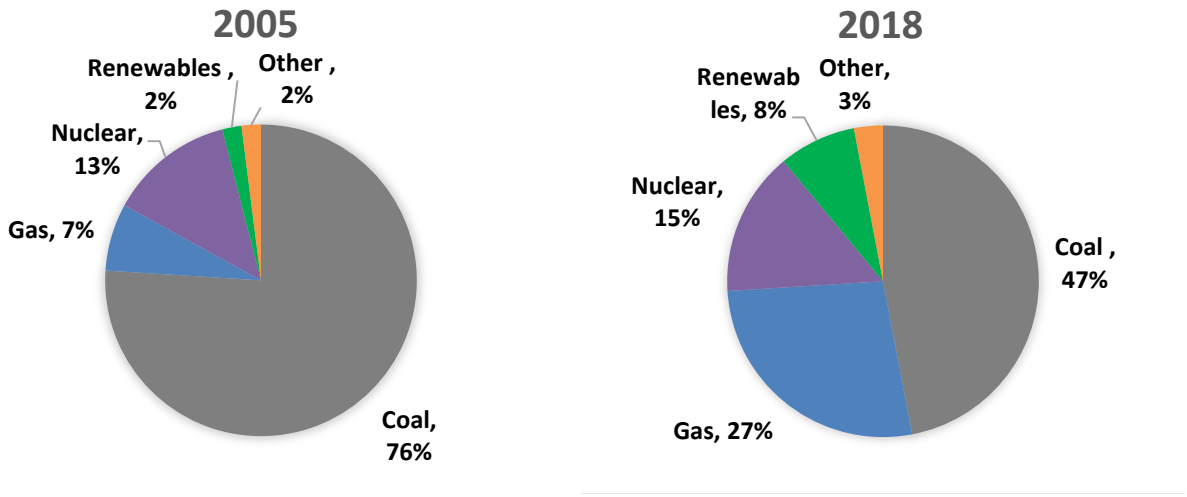
Planning Year	MISO PRMR (UCAP)-Required	MISO PRM (UCAP)-Excess Available: Offered/PRMR
2022-23	8.70%	136,906/135,326: 1.17%
2020-21	8.90%	142,082/135,960: 4.50%
2019-20	7.90%	142,082/134,743: 5.45%
2018-19	8.40%	141,781/135,179: 4.88%
2017-18	7.80%	142,146/134,753: 5.49%
2016-17	7.60%	141,524/135,483: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

5.3 MISO Resource Mix – Past, Current and Future

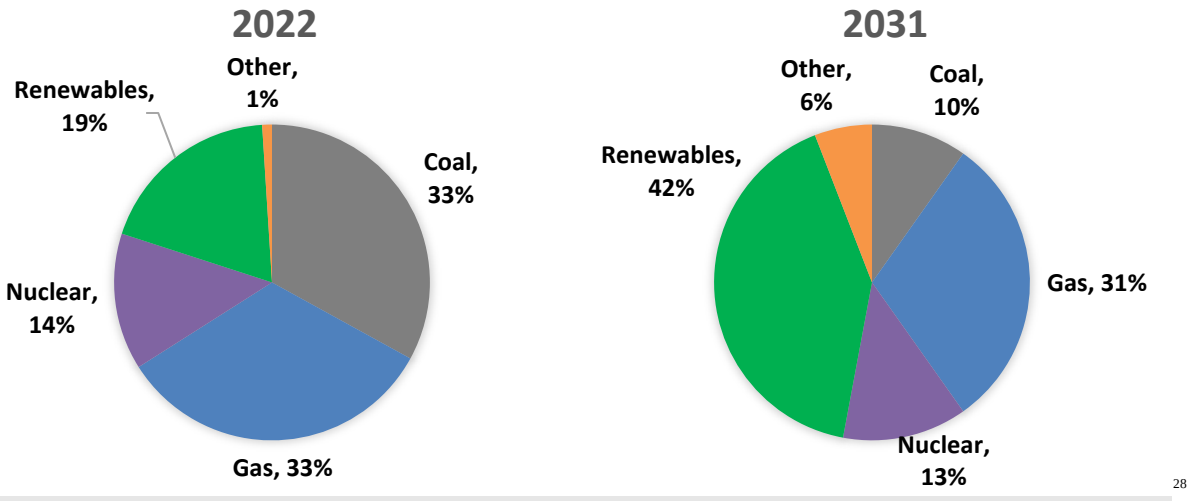
MISO's resource fuel mix has changed drastically since its market inception in 2005. In 2005, coal was the predominant fuel source, with MISO lacking diversity and nuclear as the closest competitor at 13%. In 2018, after the implementation of MATS, the release of the Clean Power Plan and various other 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]

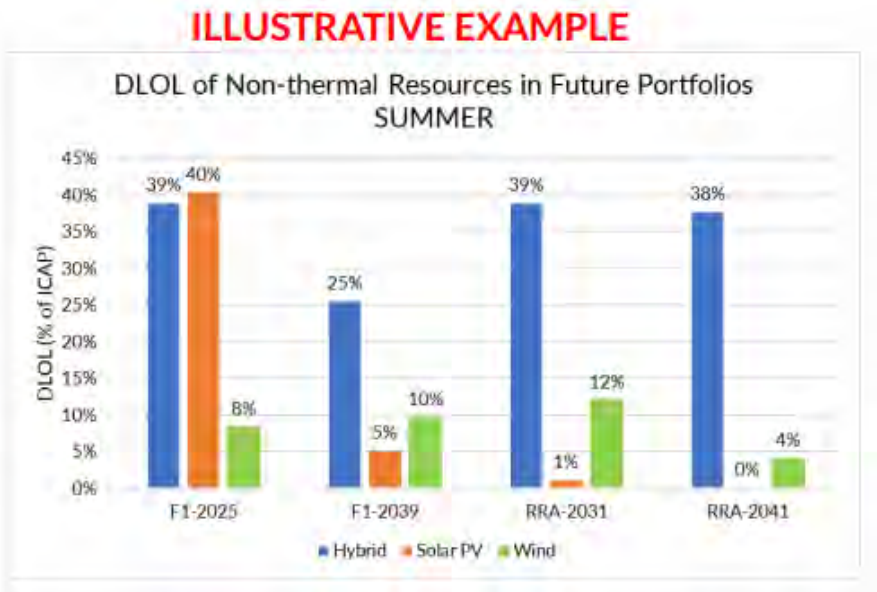
5.4 Dispatchable vs. Intermittent

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]

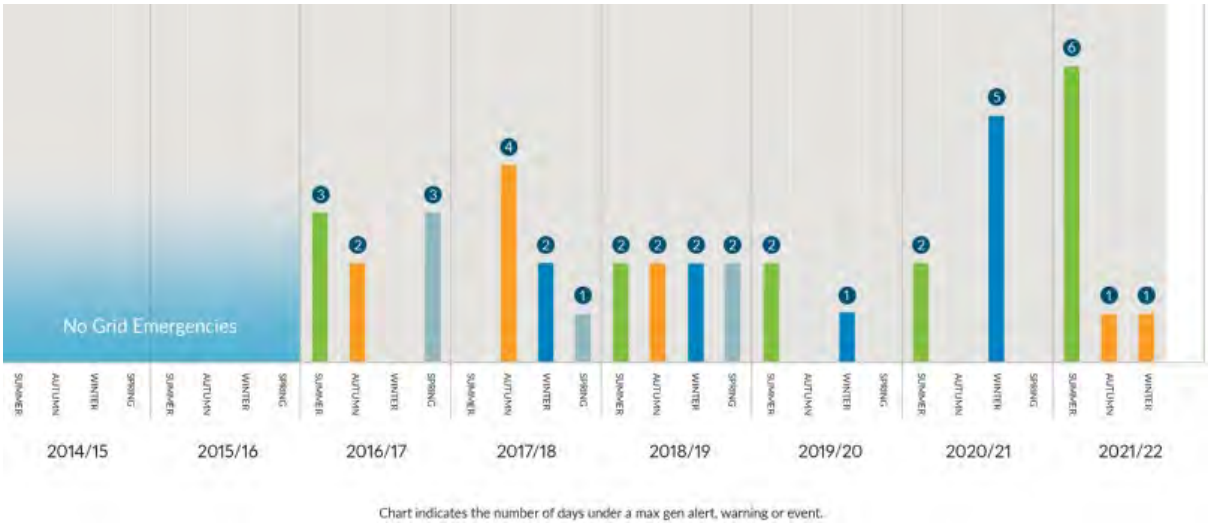


[29] MISO Corporate Fact Sheet accessed 04/23 - https://www.misoenergy.org/about/media-center/corporate-fact-sheet/
[30] 2022 Regional Resource Assessment – November 2022 – Page 22 - https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf
[31] MISO; March 1, 2023 Resource 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.

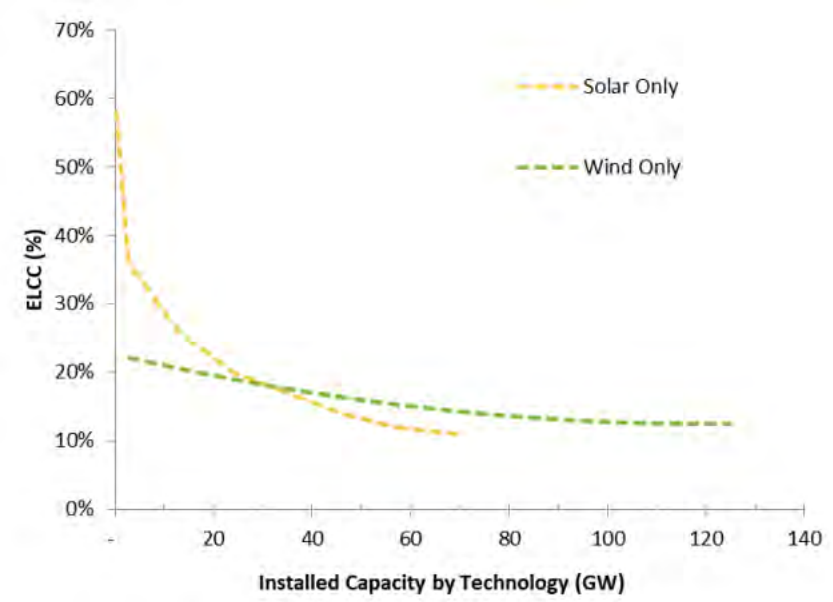
5.7 MISO CAPACITY CREDIT

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]

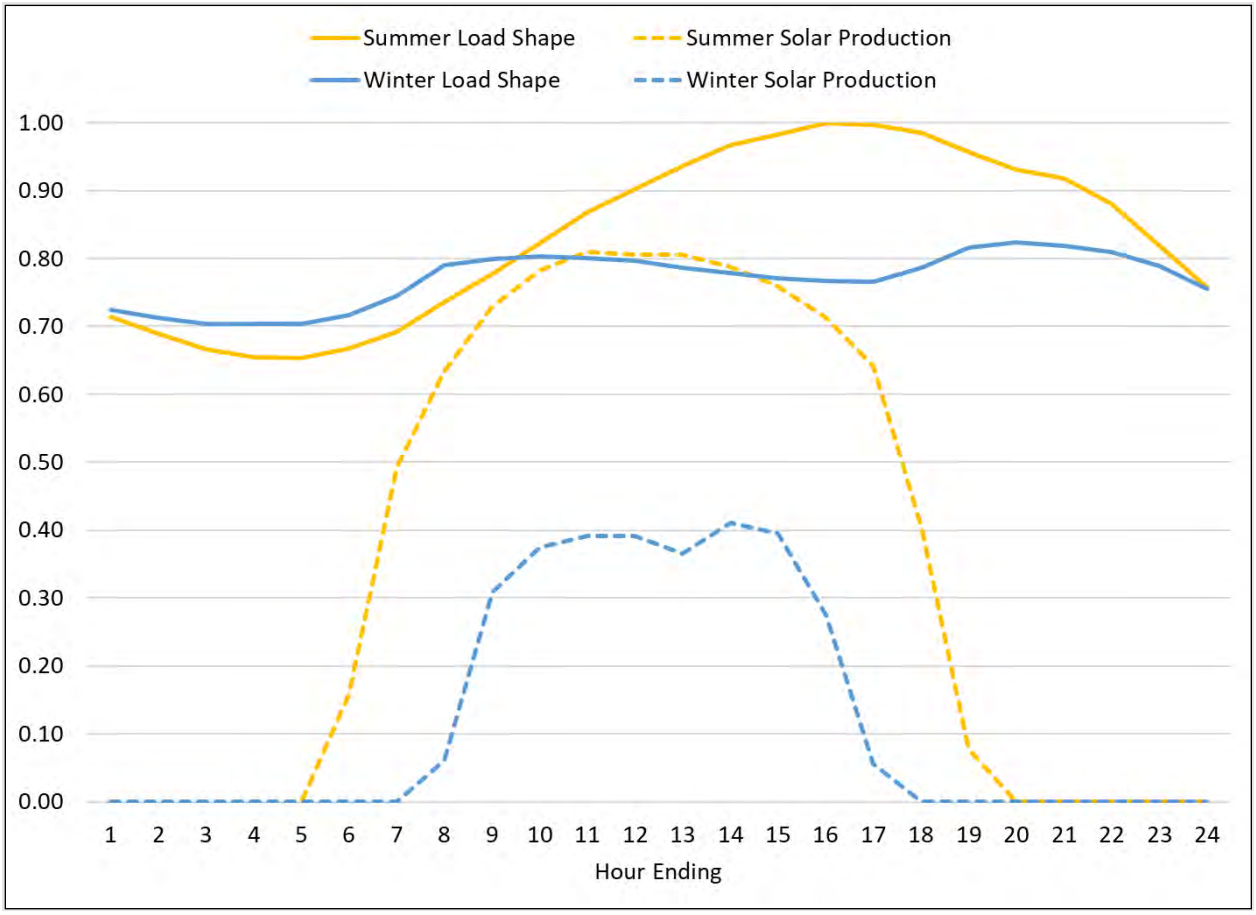


The solar and wind accreditation used in the IRP modeling was calculated using MISO's ELCC accreditation formulas and adjusted based upon the level of renewable penetration expected on MISOs system. As additional renewable resources were included in the model the UCAP accreditation for these resources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

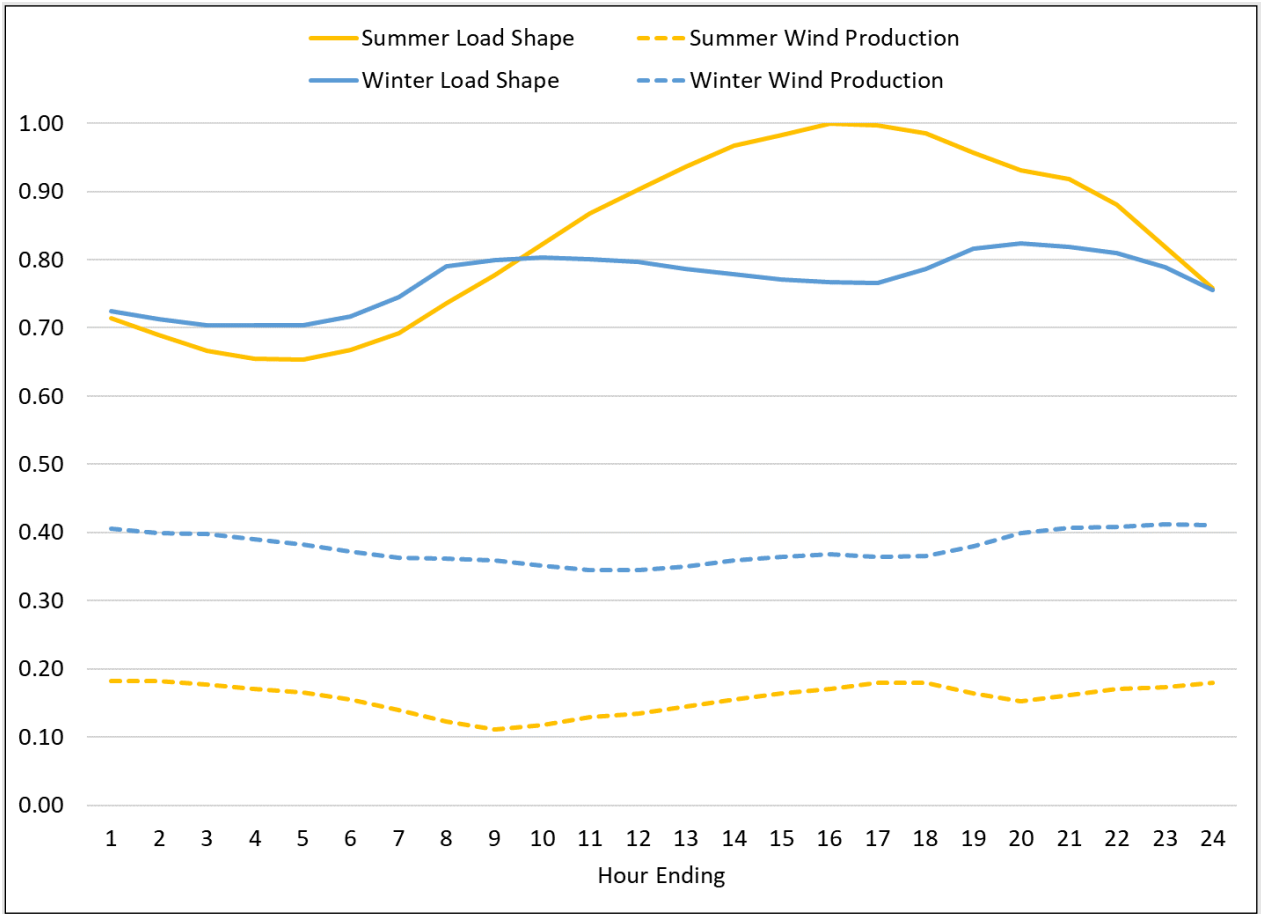
[34] MISO's Renewable Integration Impact Assessment (RIIA) Summary Report February 2021, MISO, page 29, https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

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



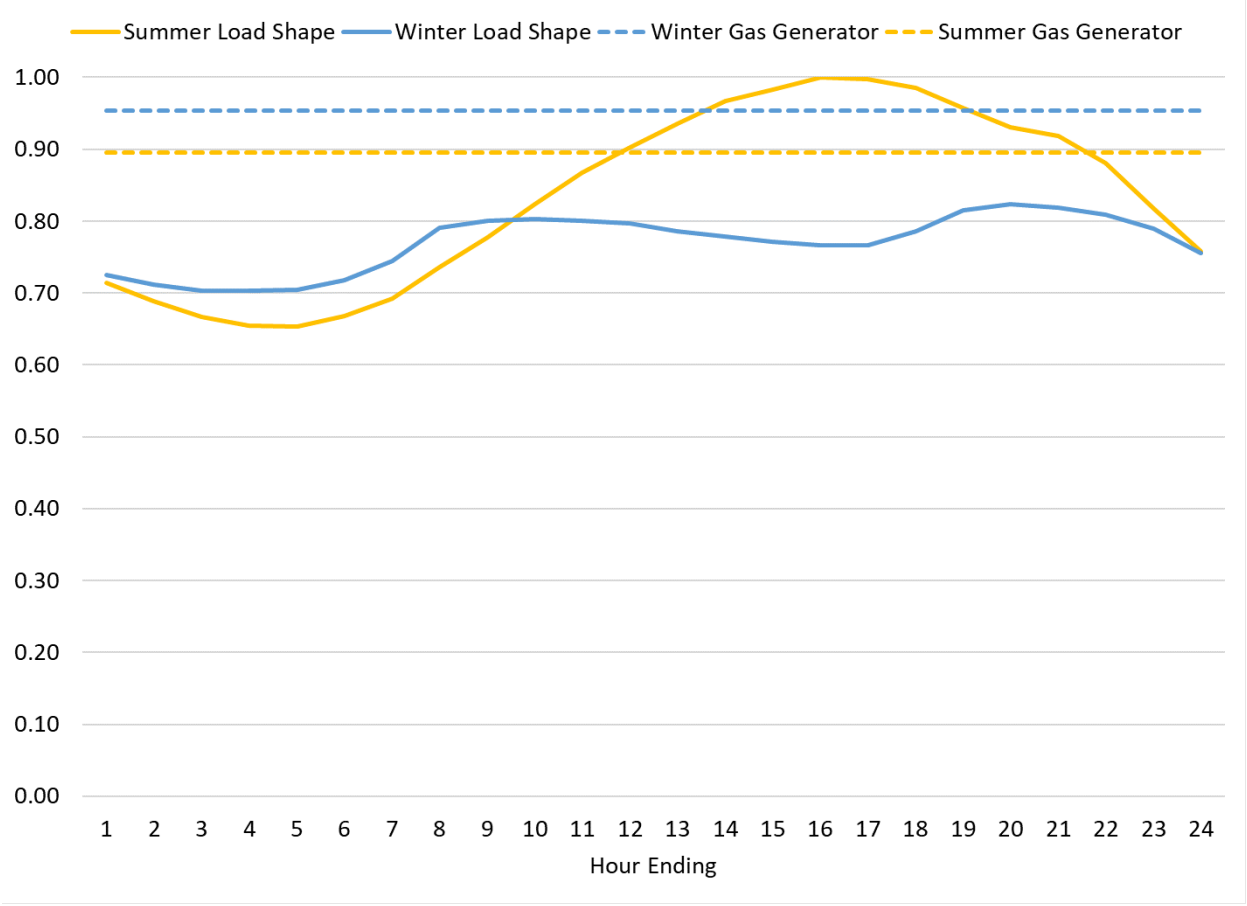
Wind resources typically have higher capacity factors during winter months leading to a higher output during winter peak demand hours. Summer and winter wind production compared to load shapes are shown in Figures 5.10.

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.

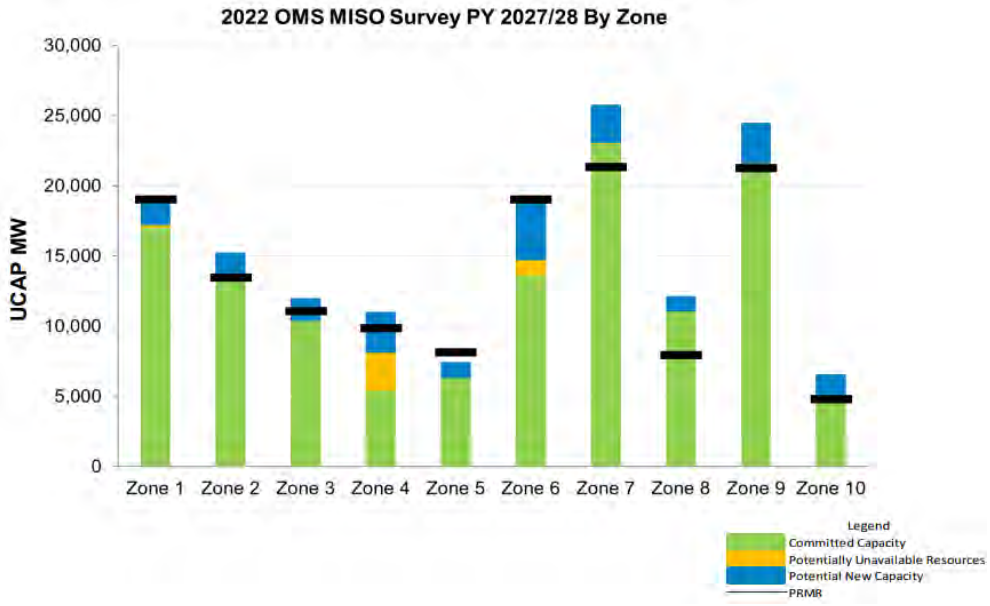
5.8 MISO Capacity

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.

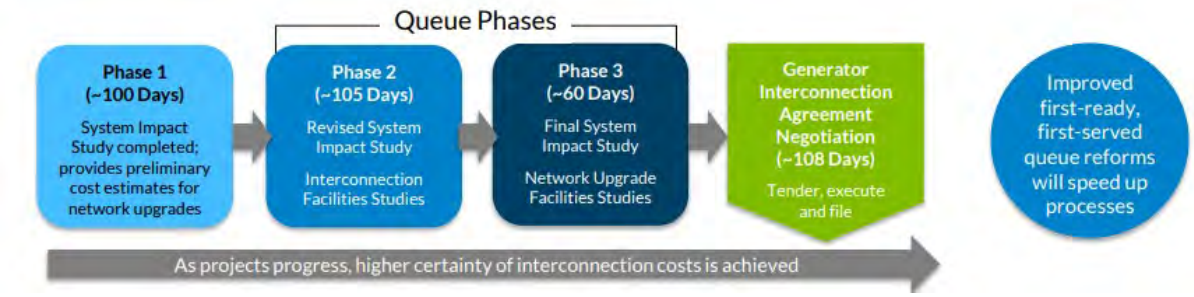
The DPP process is broken down into three phases and two decision points, following the completion of the first two phases (studies) the interconnection customer will once again have the chance to adjust the project size and move to the next phase as well as to withdraw from the queue. Upon completion 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

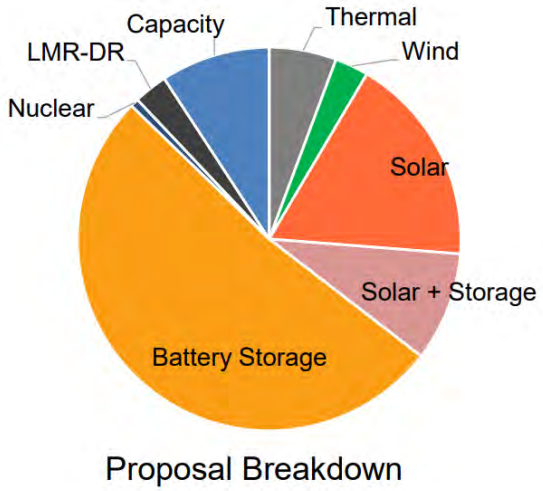
Respondents were given two weeks to submit a Notice of Intent to participate in the RFP process, sign the Non-Disclosure Agreement and complete the Pre-Qualification Application. The purpose of the Pre-Qualification Application is to verify Respondents have adequate experience and financial capability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

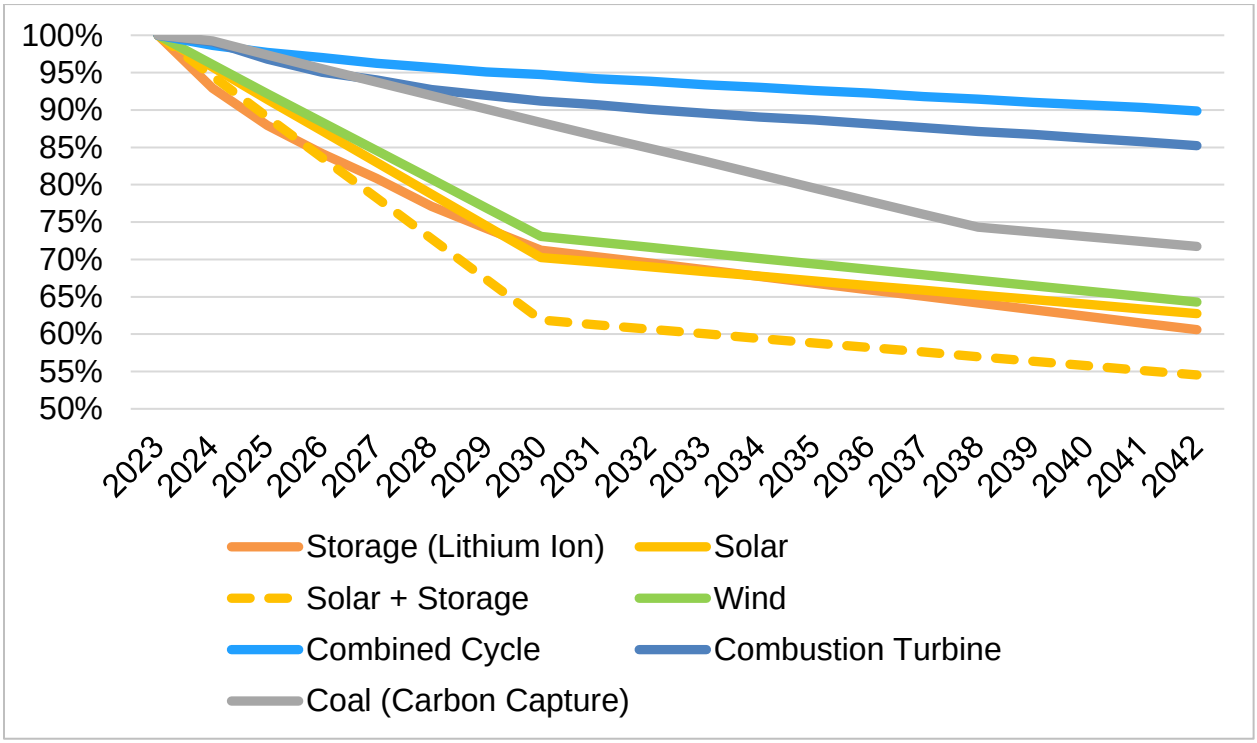
Operating Characteristics and Estimated Costs	Lithium Ion 10 MW / 40 MWh	Lithium Ion 50 MW / 200 MWh	Long-Duration Proxy 100 MW / 400 MWh	Long-Duration Proxy 300 MW / 3,000 MWh
Base Load Net Output (MW)	10	50	100	300
Round-Trip Cycle Efficiency	85%	85%	85%	60%
Base Project Costs (2022$/kW)	$2,500	$2,160	$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.

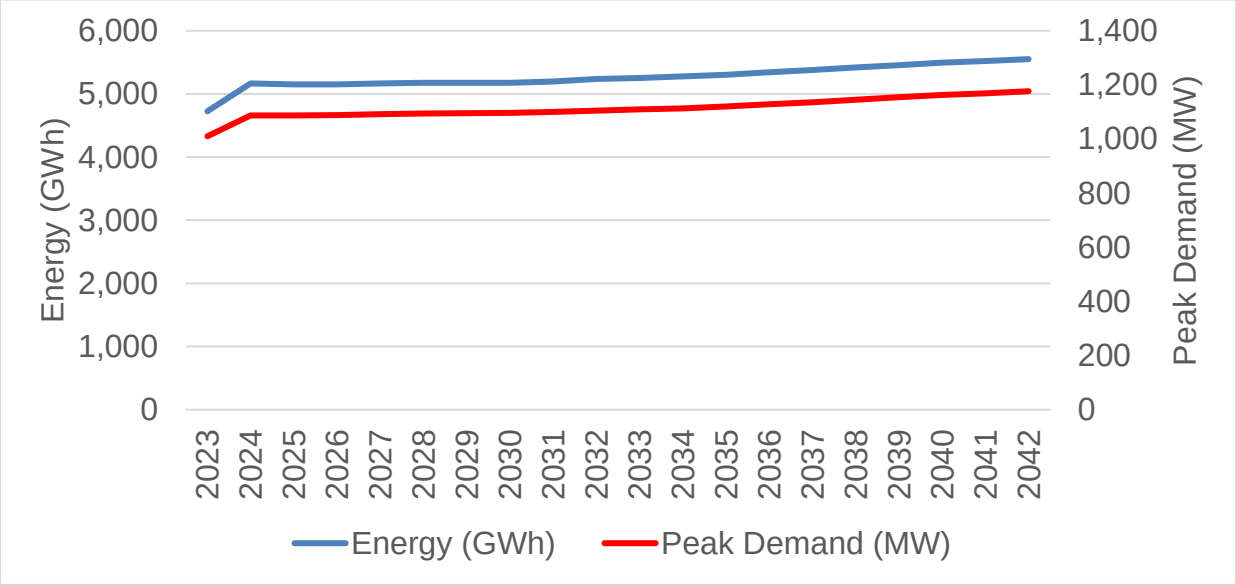
Long Term: In the long-term (2032-2042), the suite of market outcomes and drivers in the Reference Case settles into a pattern of moderate growth based on a well-balanced market. Energy sales grow at a moderate pace (0.7% CAGR for 2023-2042)[60]. The consensus forecast for Henry Hub has prices reaching $4.76/MMBtu by 2042 (in real 2023$), 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)

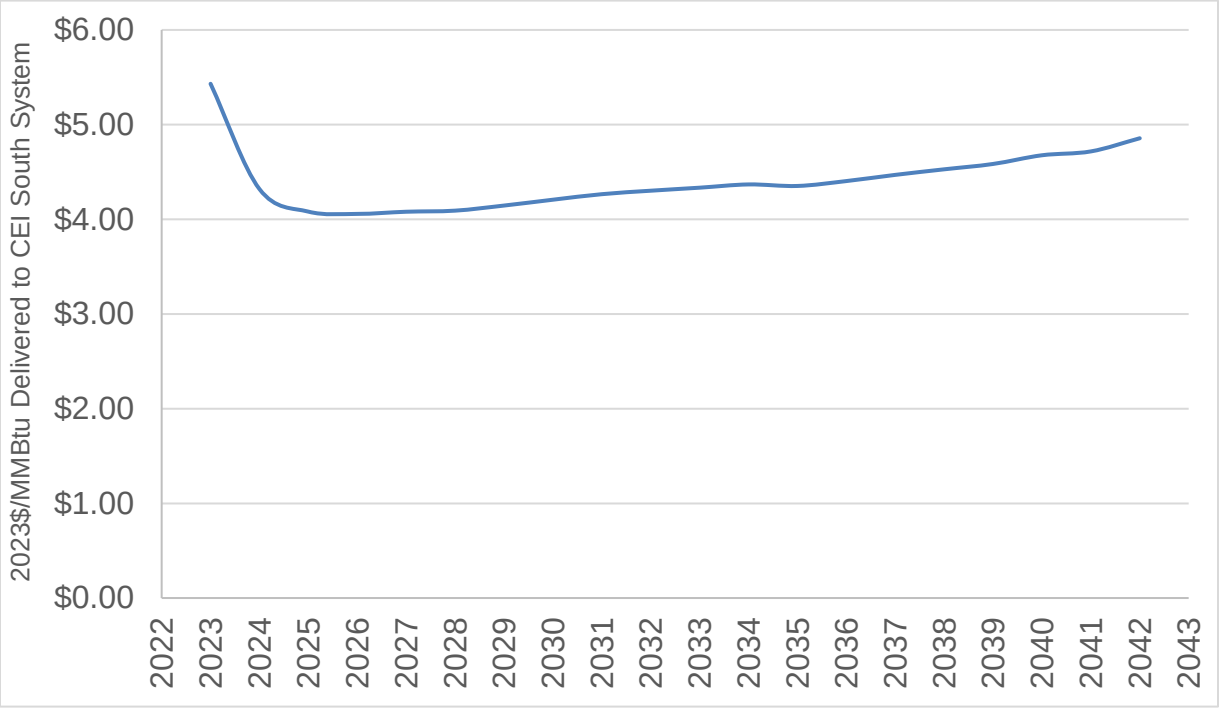
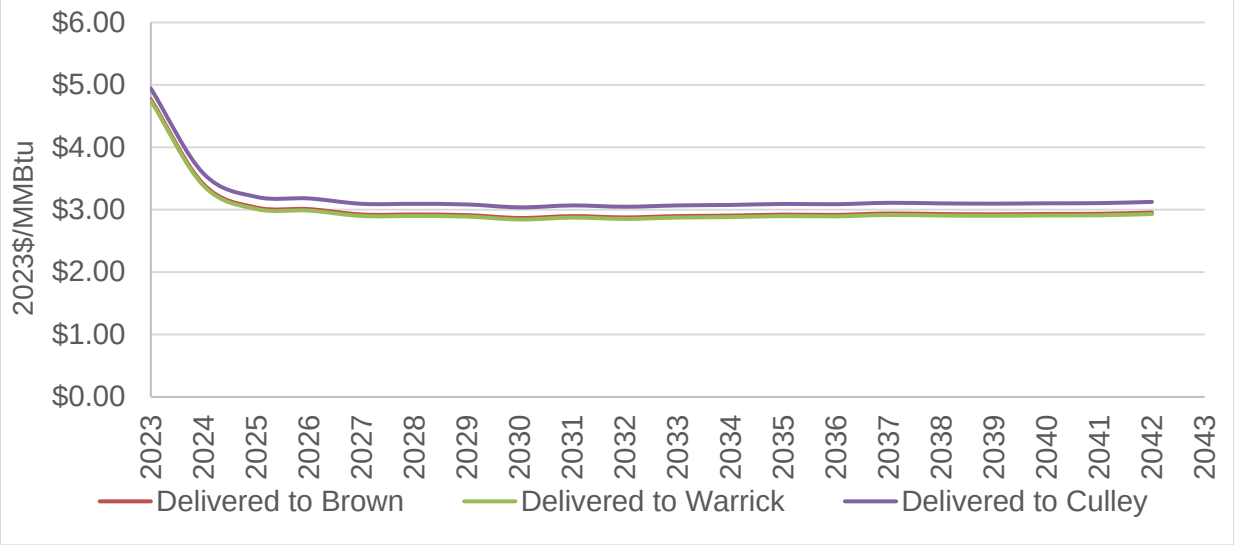


Figure 7.3 – Reference Case Coal Price Forecast (2023$/MMBtu)



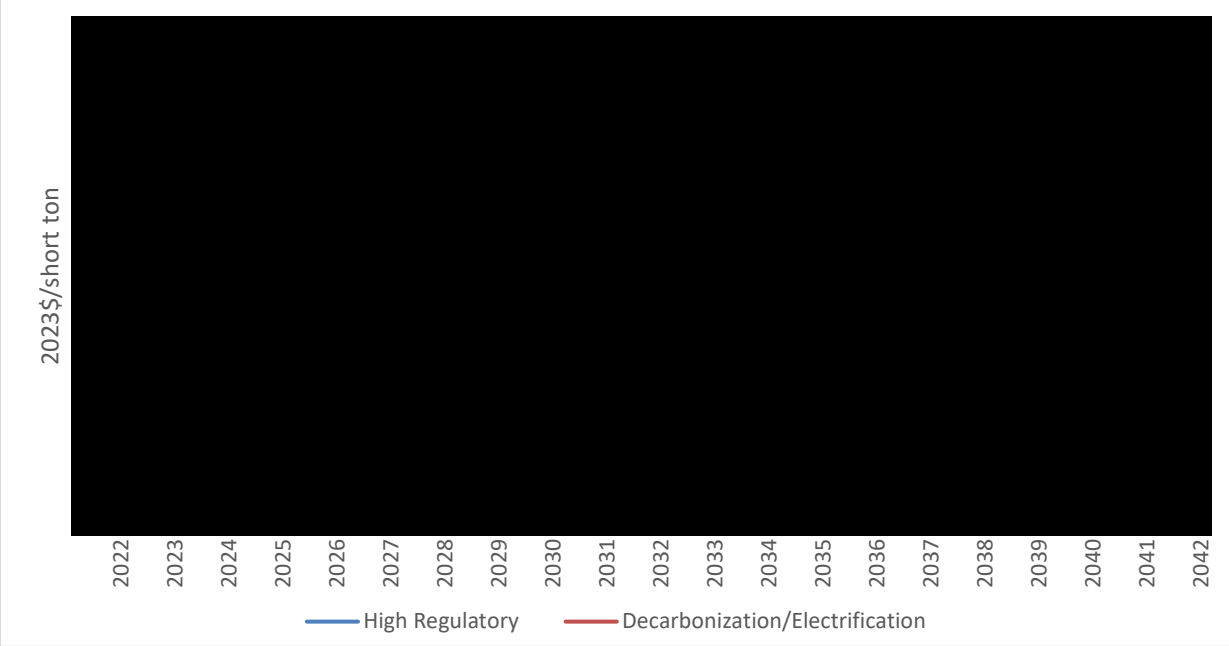
During this analysis, no comprehensive national legislation of carbon emissions existed in the United States. Efforts to enact federal policy covering carbon emissions from major

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.

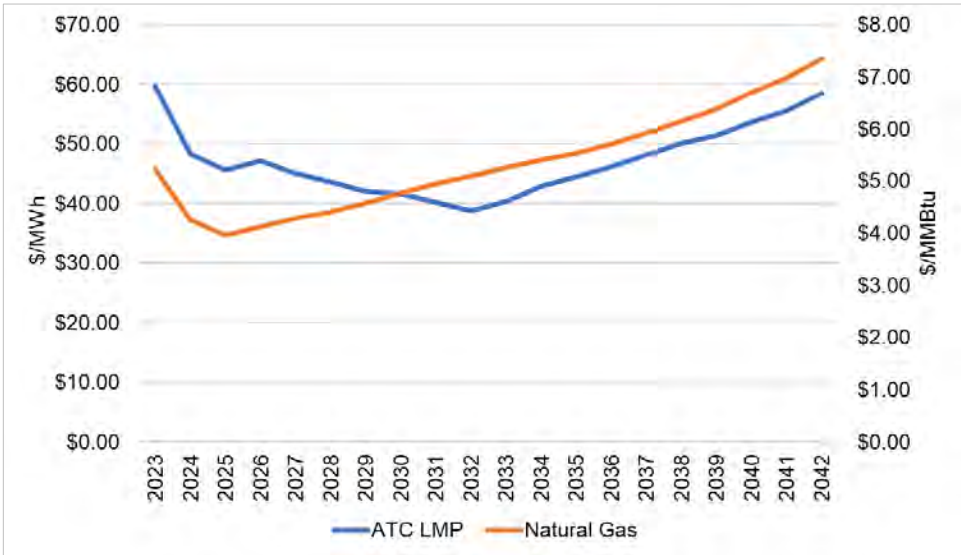
7.2.2 Energy Prices

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.

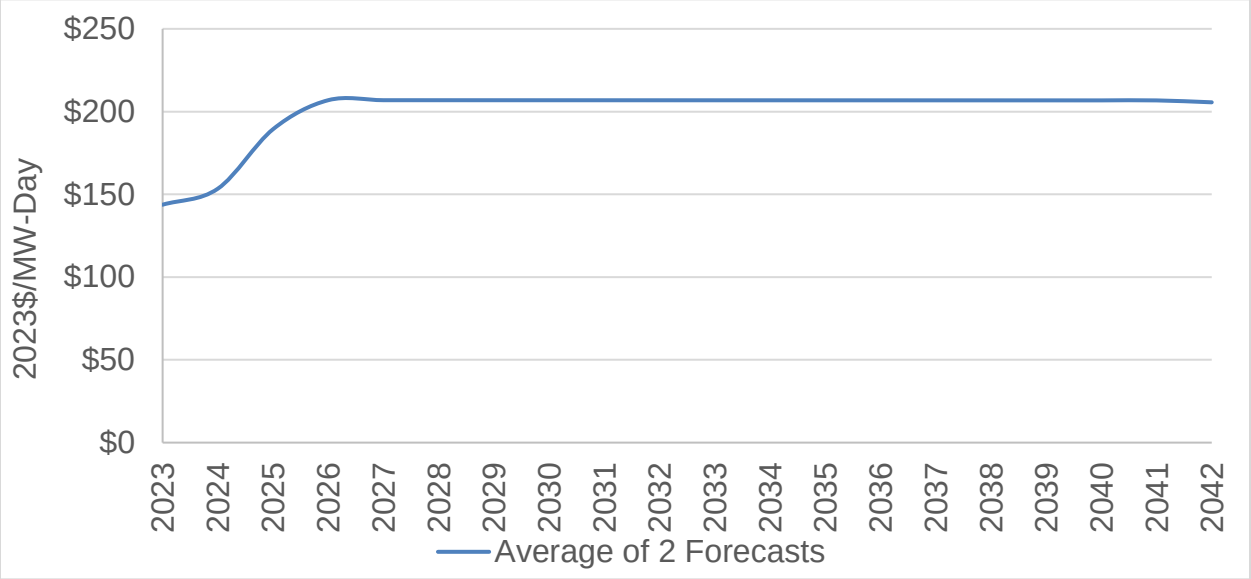
7.2.3.5 Market Capacity Price

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

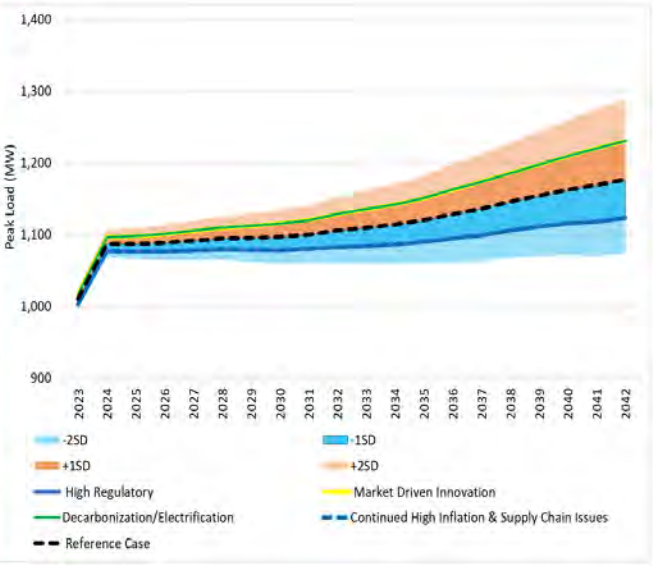


Figure 7.9 – Coal (Illinois Basin) Alternate Scenarios ($/MMBtu)

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

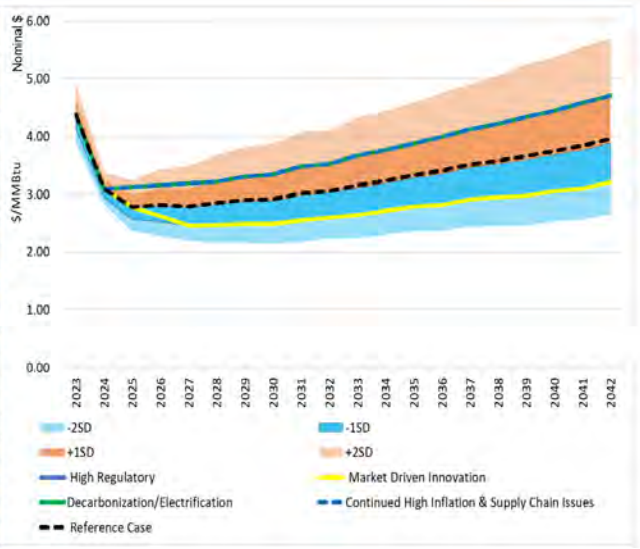


Figure 7.10 – Natural Gas (Henry Hub) Alternate Scenarios ($/MMBtu)

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

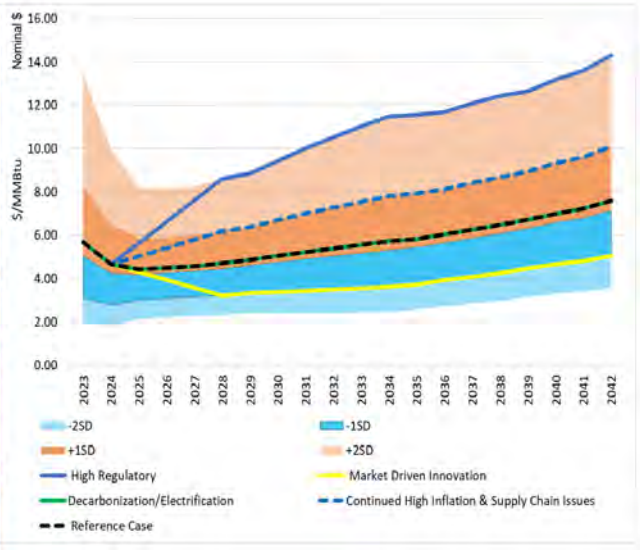


Figure 7.11 – Solar Capital Costs Alternate Scenarios (100 MW) ($/kW)[66]

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

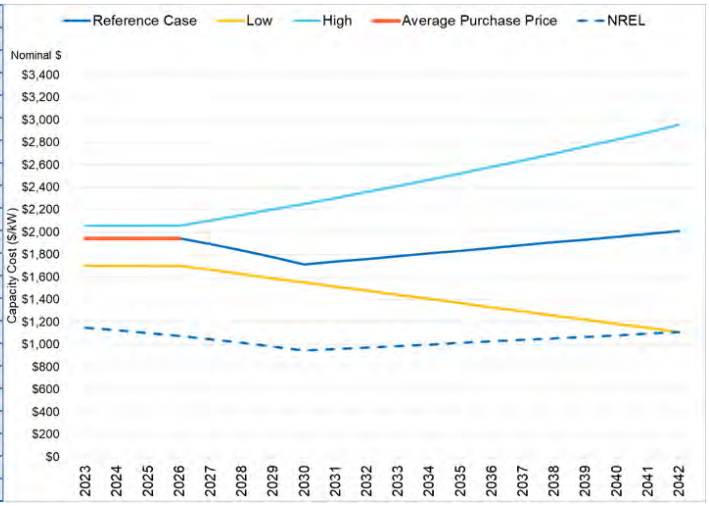
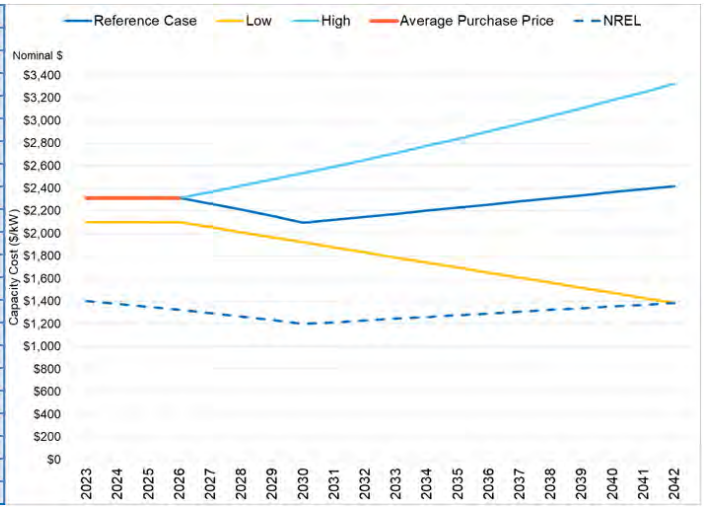


Figure 7.12 – Wind Capital Costs Alternate Scenarios (200 MW) ($/kW)[67]

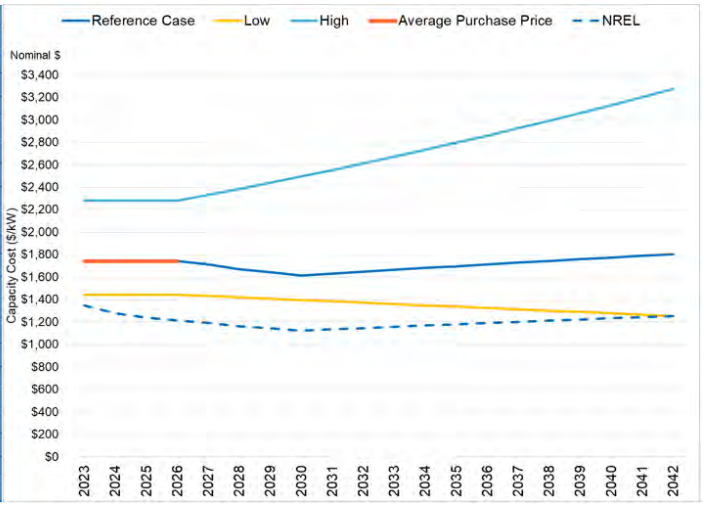
Year	Reference Case	Low	High	NREL
2022	$2,314	$2,100	$2,314	$1,423
2023	$2,314	$2,100	$2,314	$1,400
2024	$2,314	$2,100	$2,314	$1,377
2025	$2,314	$2,100	$2,314	$1,351
2026	$2,314	$2,100	$2,314	$1,325
2027	$2,265	$2,055	$2,367	$1,297
2028	$2,212	$2,011	$2,421	$1,266
2029	$2,155	$1,966	$2,477	$1,234
2030	$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

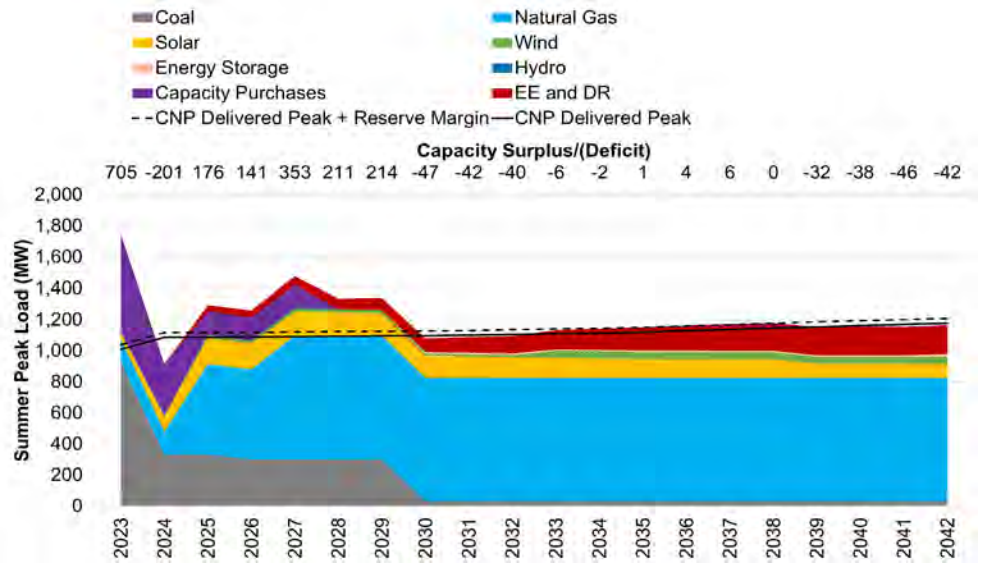


Figure 8.4 – Reference Case Winter Capacity

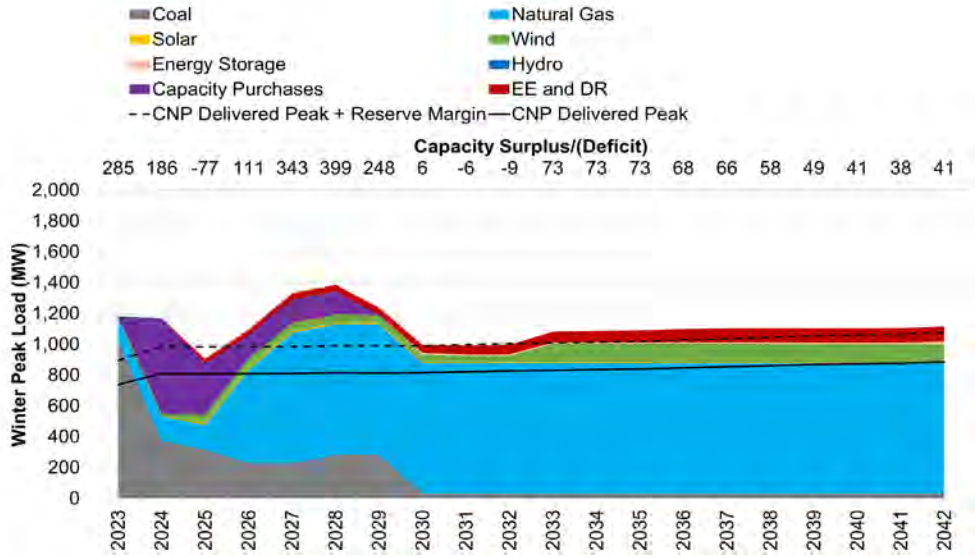
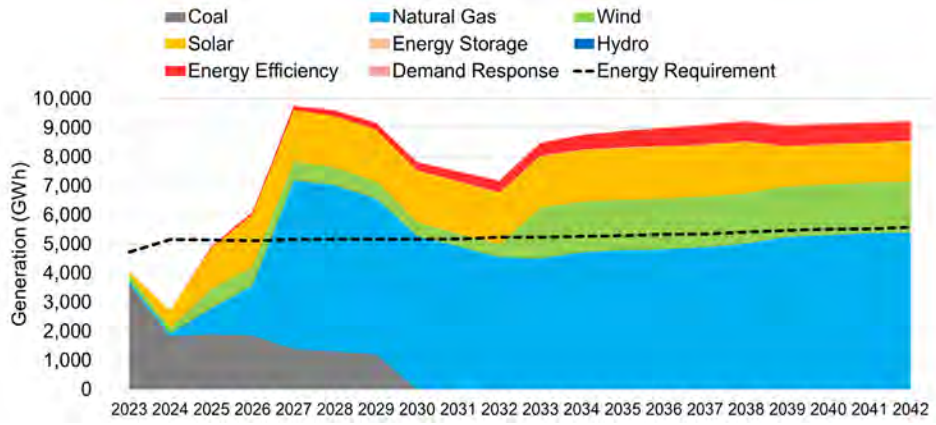


Figure 8.5 – Reference Case Energy (Reference Case Conditions)



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

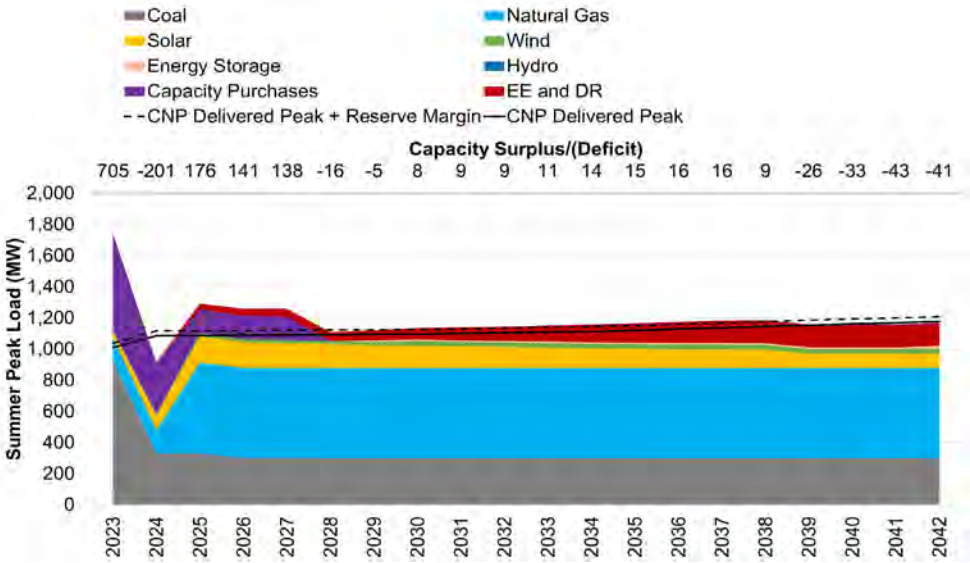


Figure 8.7 – BAU Winter Capacity

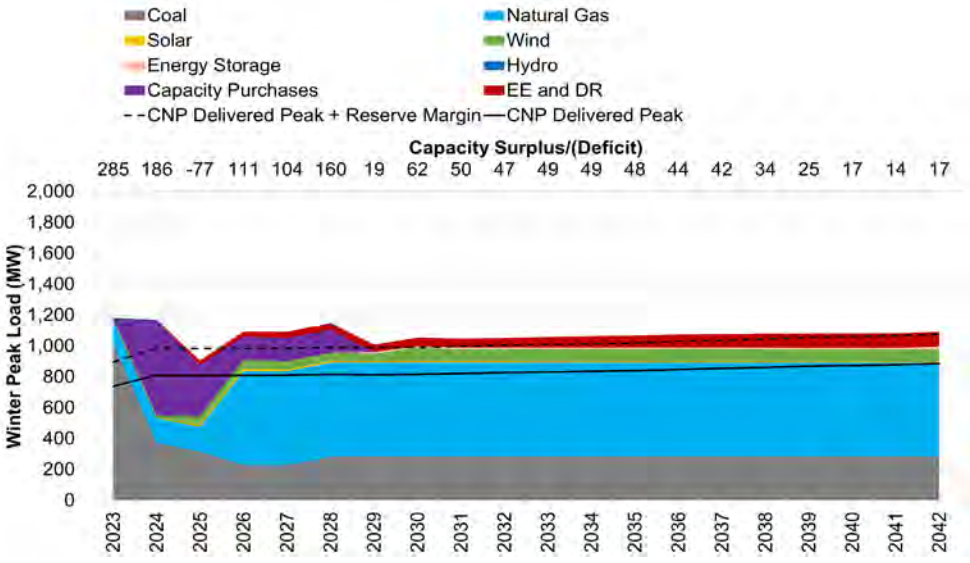
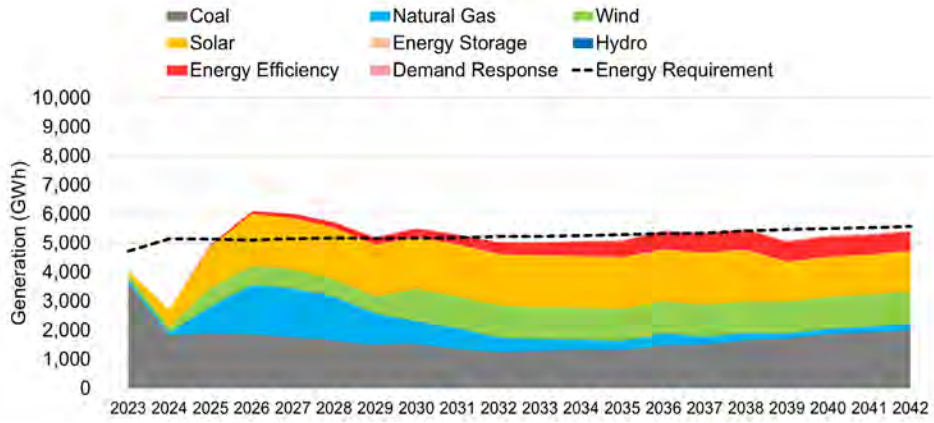


Figure 8.8 – BAU Energy (Reference Case Conditions)



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

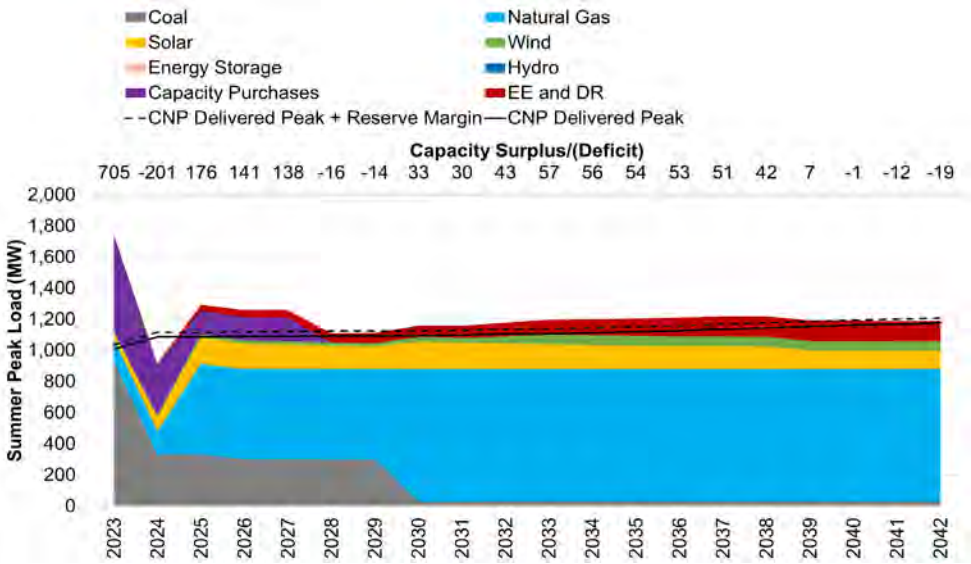


Figure 8.10 – Convert F.B. Culley 3 to Natural Gas by 2030 Winter Capacity

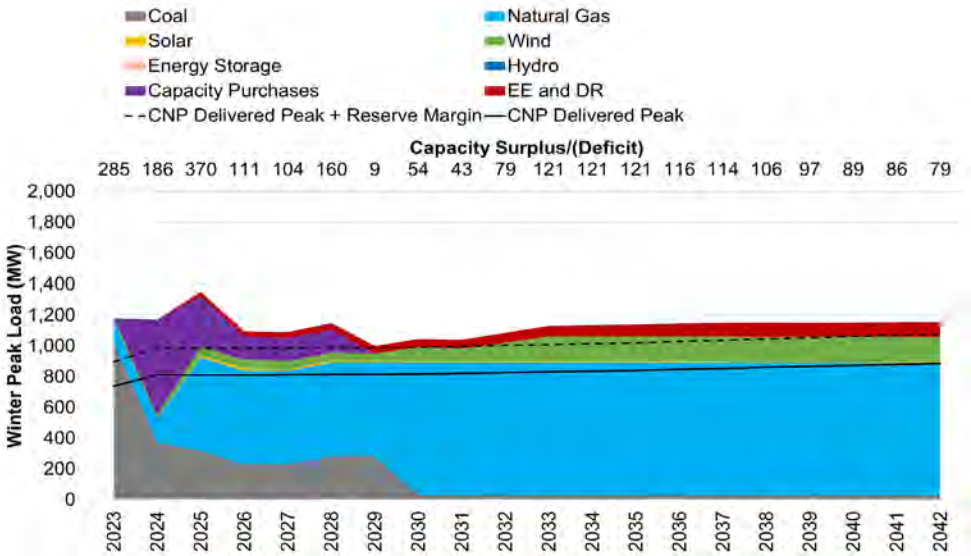
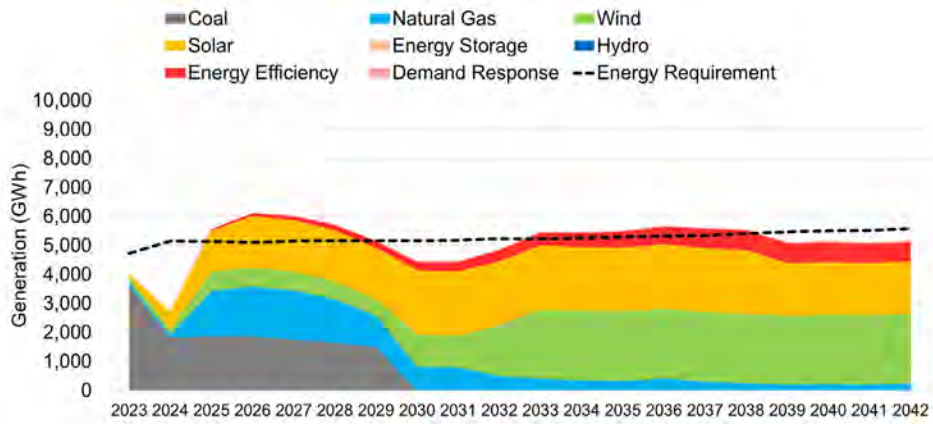


Figure 8.11 – Convert F.B. Culley 3 to Natural Gas by 2030 Energy (Reference Case Conditions)



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

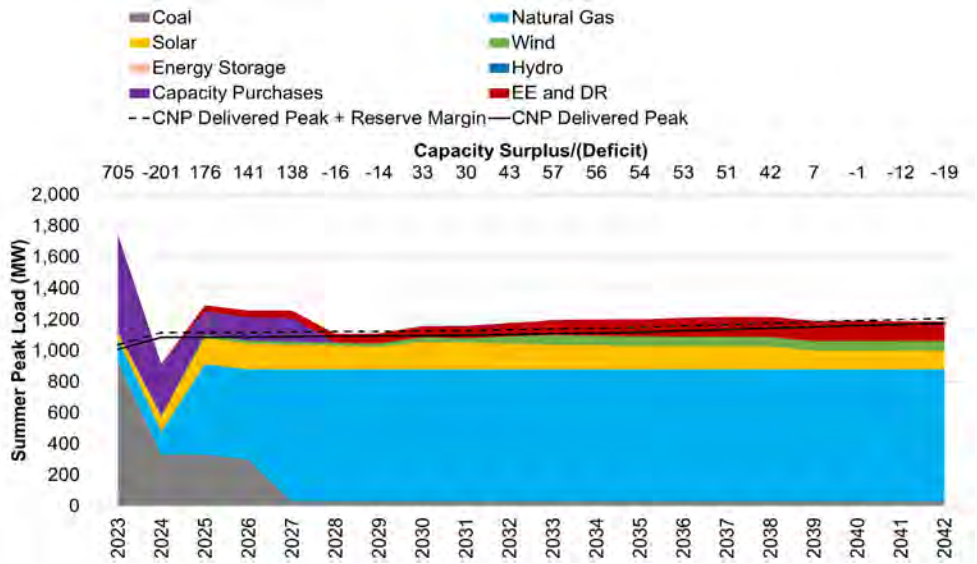


Figure 8.13 – Convert F.B. Culley 3 to Natural Gas by 2027 Winter Capacity

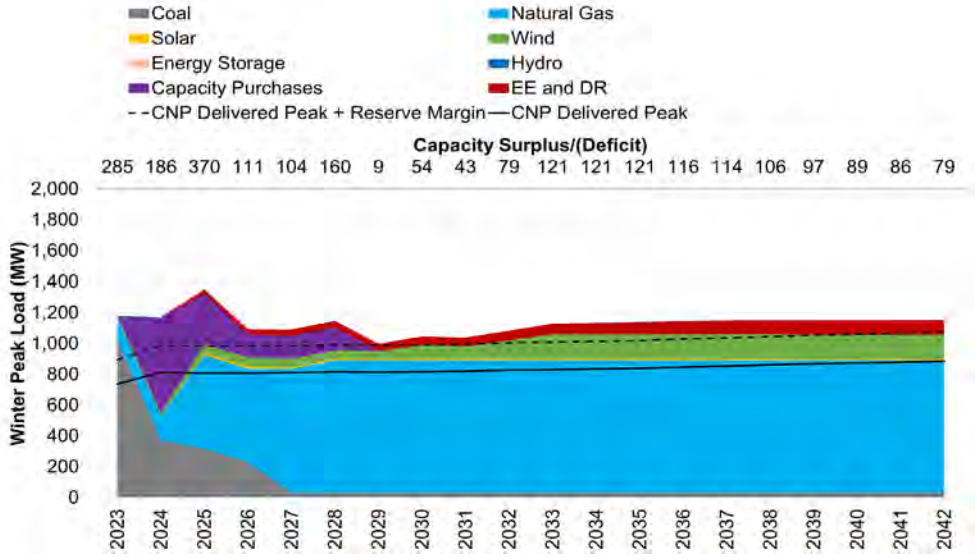
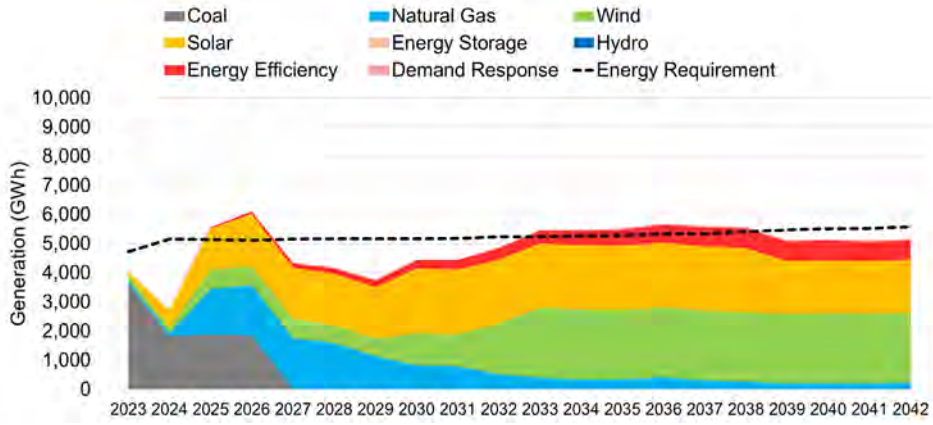


Figure 8.14 – Convert F.B. Culley 3 to Natural Gas by 2027 Energy (Reference Case Conditions)



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

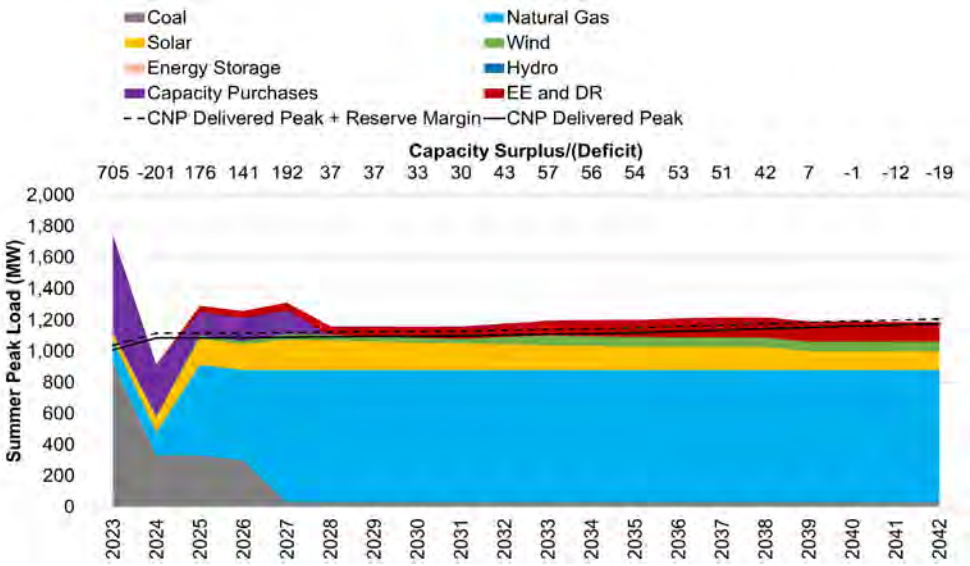


Figure 8.16 – Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 Wind and Solar Winter Capacity

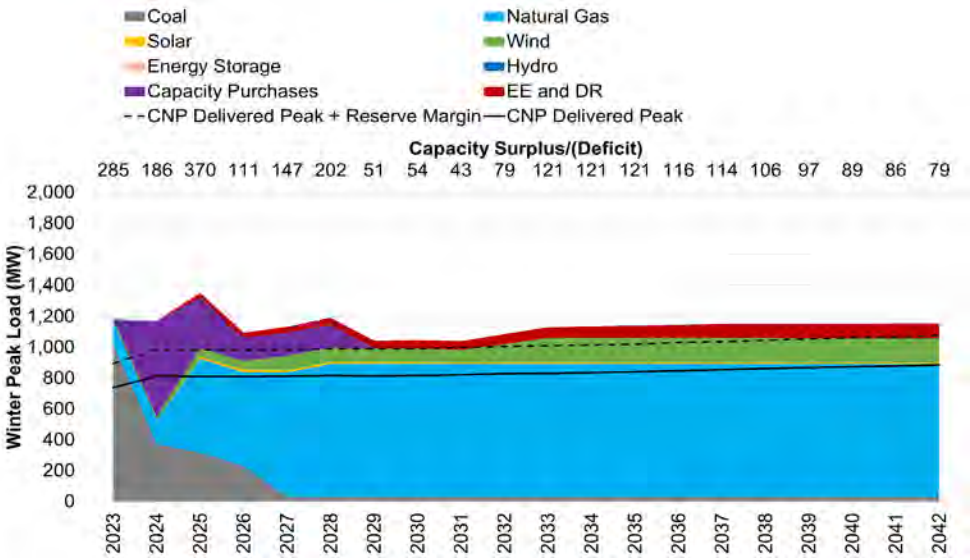
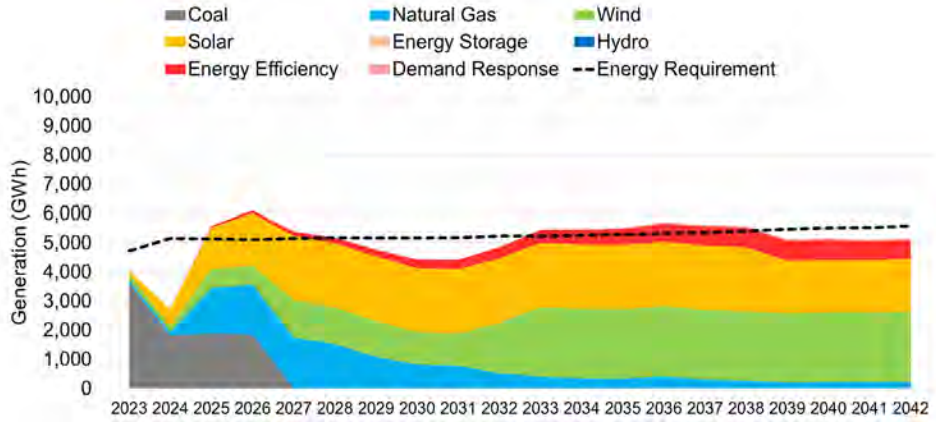


Figure 8.17 – Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 Wind and Solar Energy (Reference Case Conditions)



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

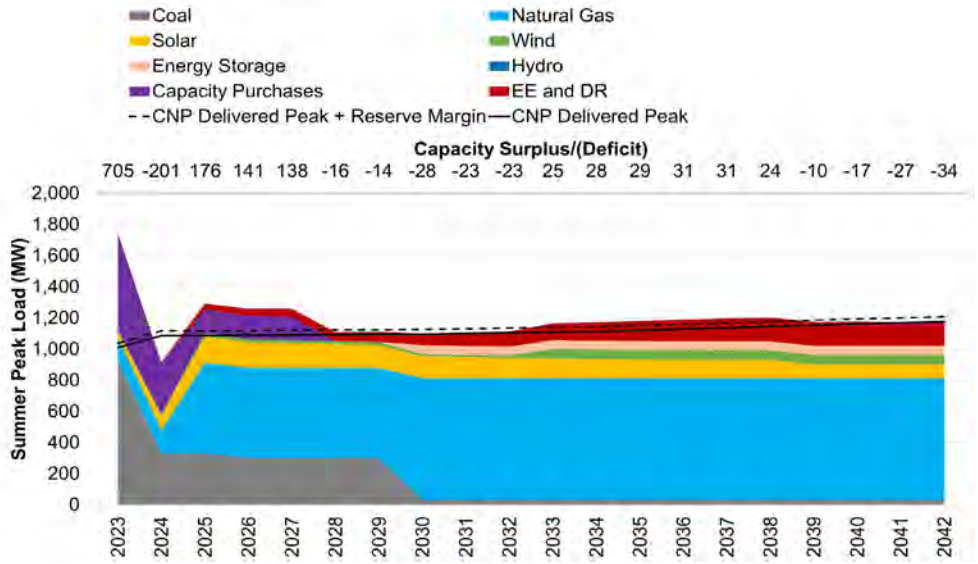


Figure 8.19 –CT Portfolio (Replace F B Culley 3 with F-Class CT) Winter Capacity

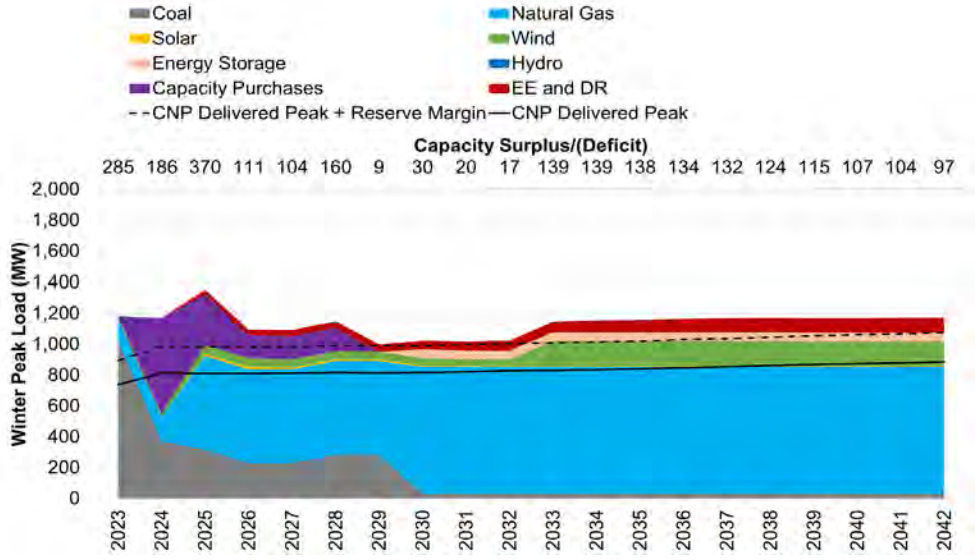
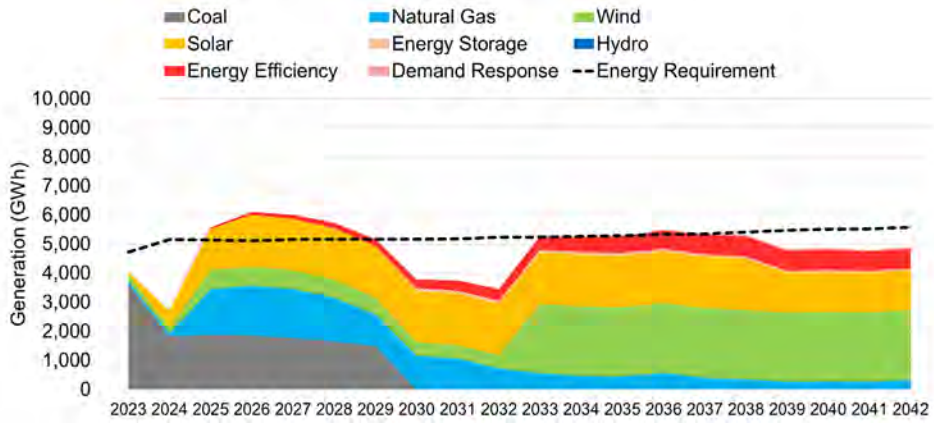


Figure 8.20 –CT Portfolio (Replace F B Culley 3 with F-Class CT) Energy



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

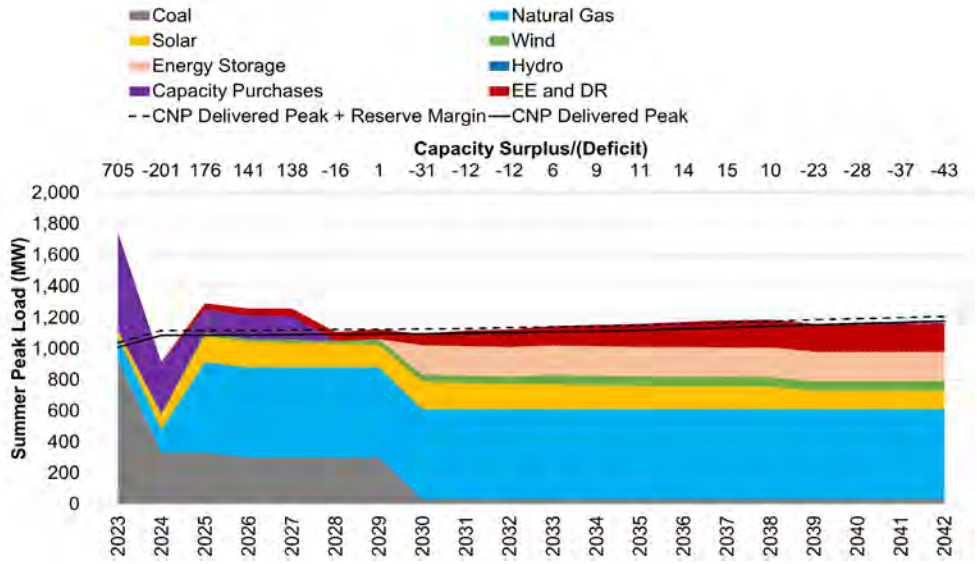


Figure 8.22– Diversified Renewables Winter Capacity

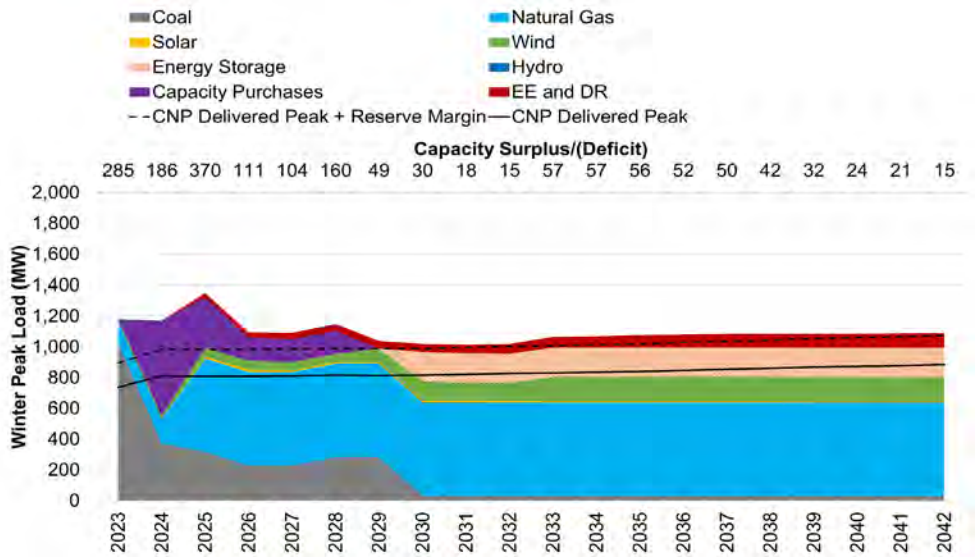
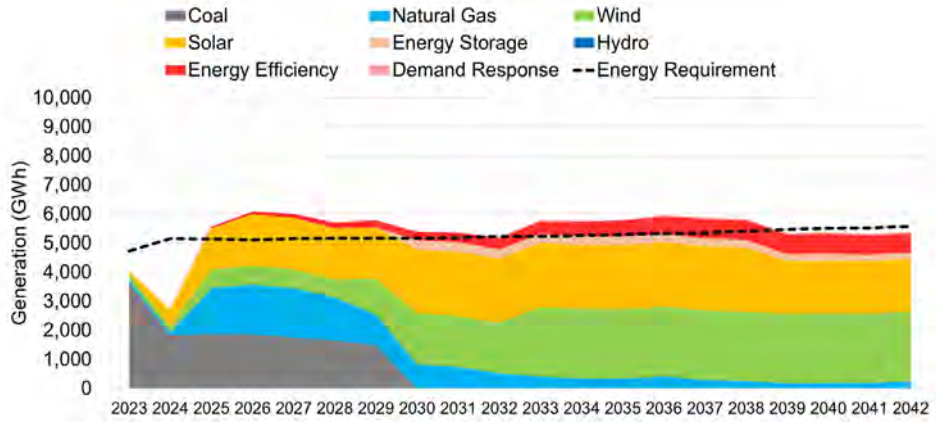


Figure 8.23– Diversified Renewables Energy



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

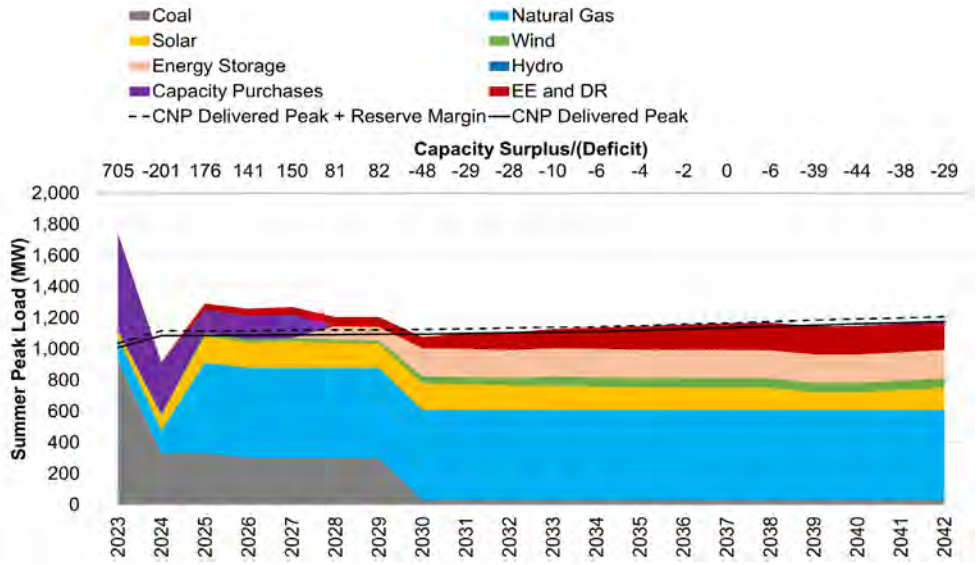


Figure 8.25– Diversified Renewables (Early Storage & DG) Winter Capacity

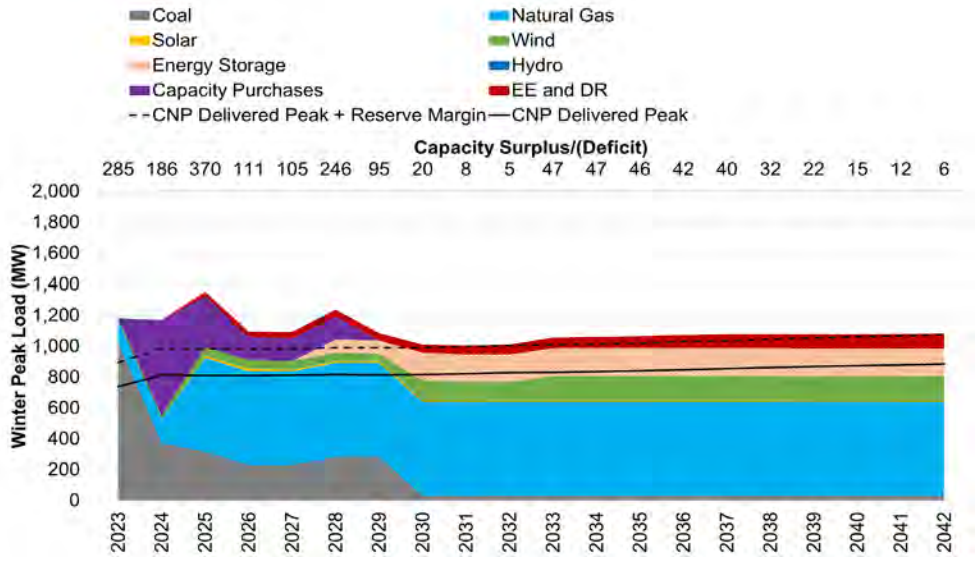
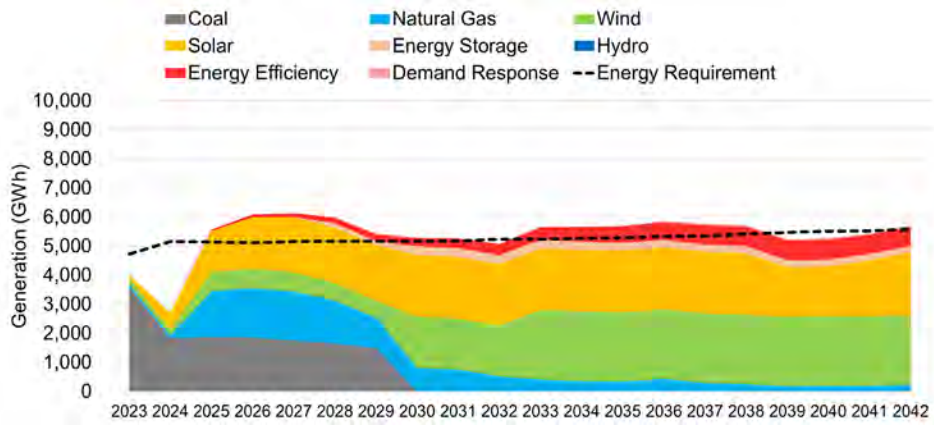


Figure 8.26– Diversified Renewables (Early Storage & DG) Energy



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

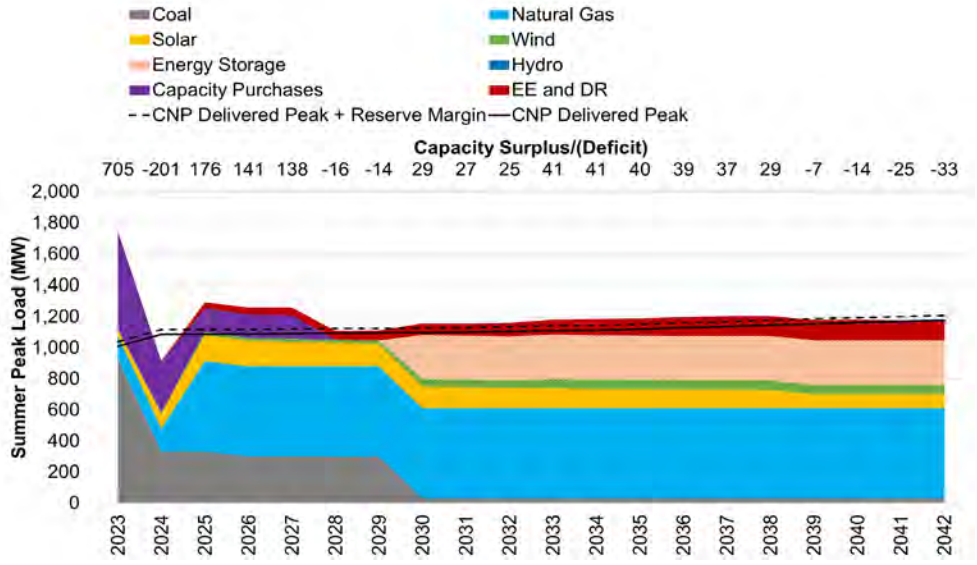


Figure 8.28– Replace F B Culley 3 with Storage and Wind Winter Capacity

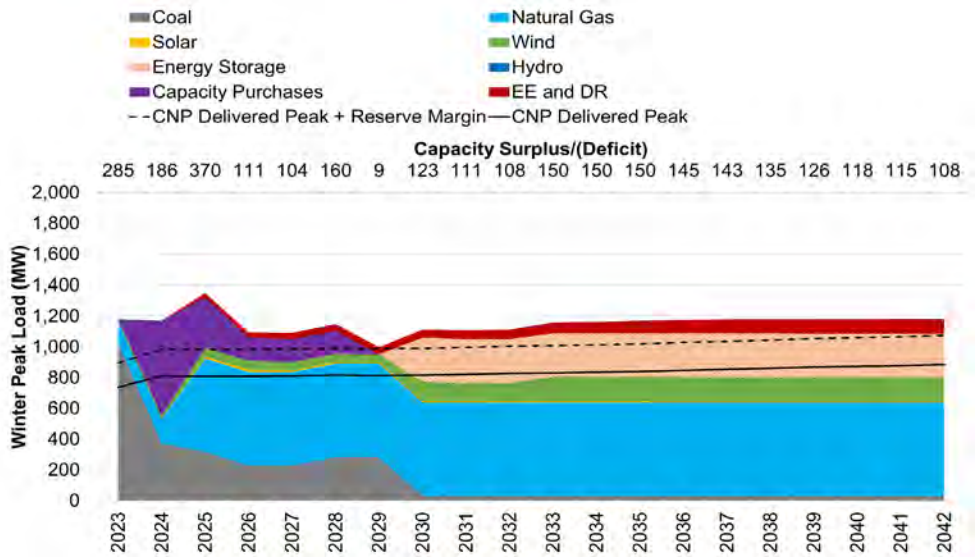
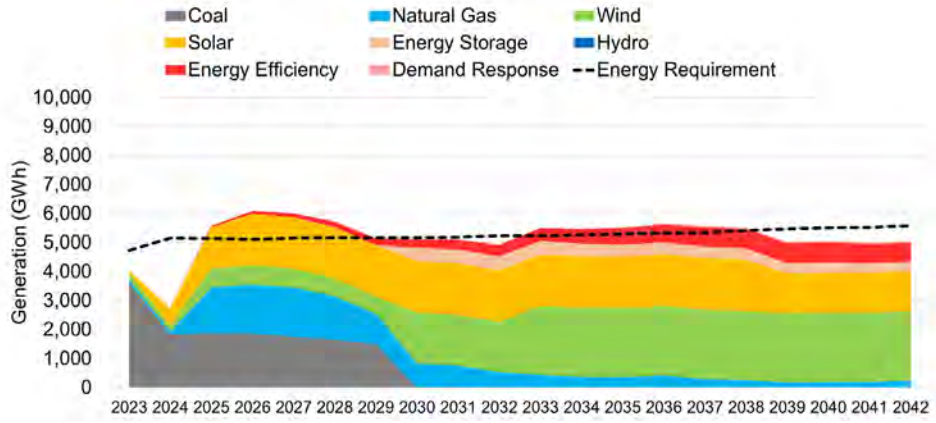


Figure 8.29– Replace F B Culley 3 with Storage and Wind Energy



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

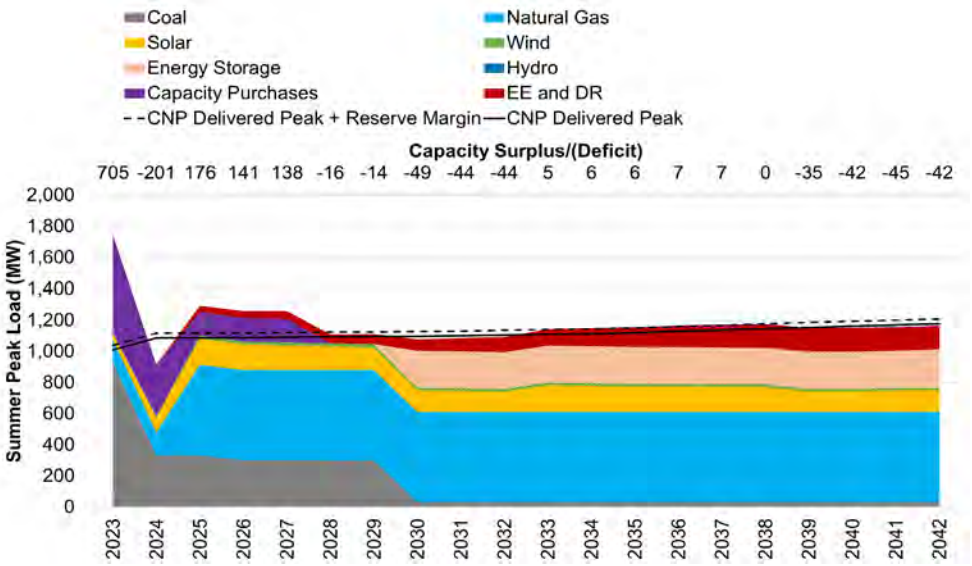


Figure 8.31– Replace F B Culley 3 with Storage and Solar Winter Capacity

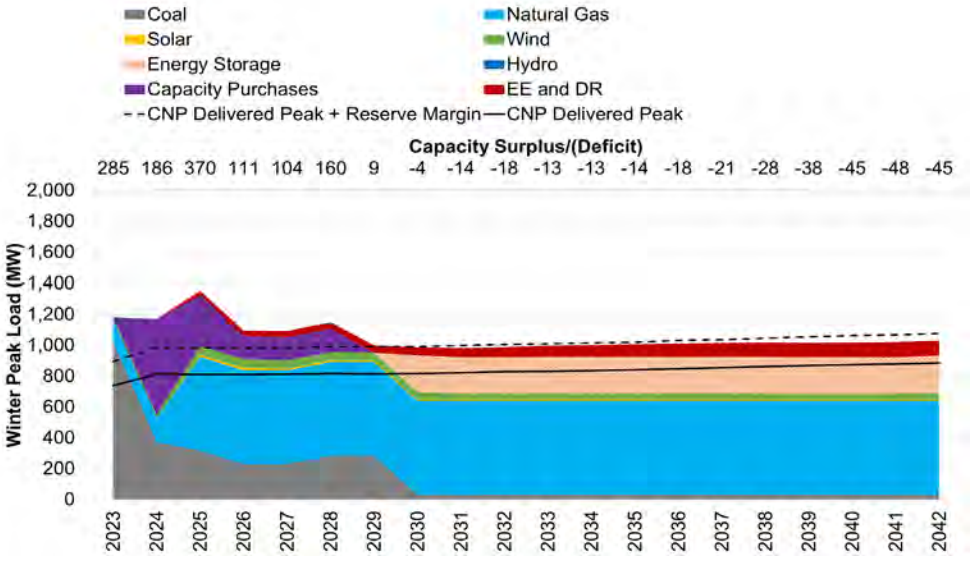
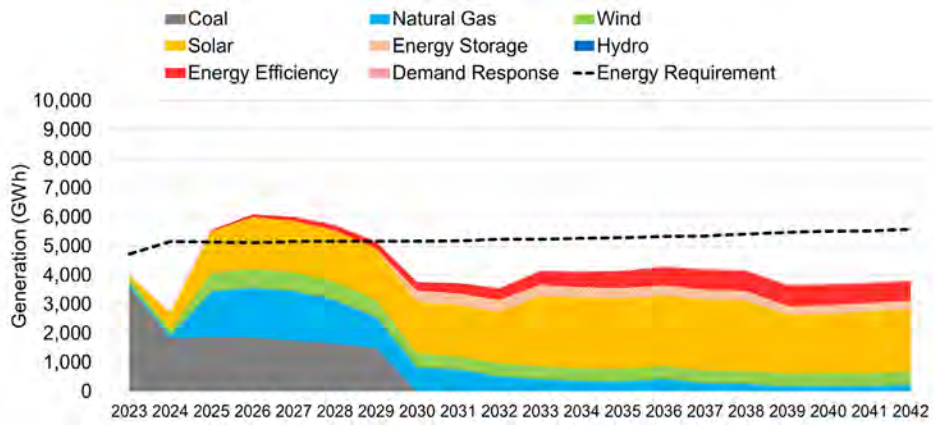


Figure 8.32– Replace F B Culley 3 with Storage and Solar Energy



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 95^{th} 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	Winter	Fast Start Capability (MW)[5]	Dispatchable Resource with Spinning Reserve Capability (MW)[6]	Energy Market Purchases[7] Average	Near Term Max	Long Term Max	Energy Market Sales[7] Average	Near Term Max	Long Term Max	Capacity Market Purchases or Sales (%)[8] Purchases	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

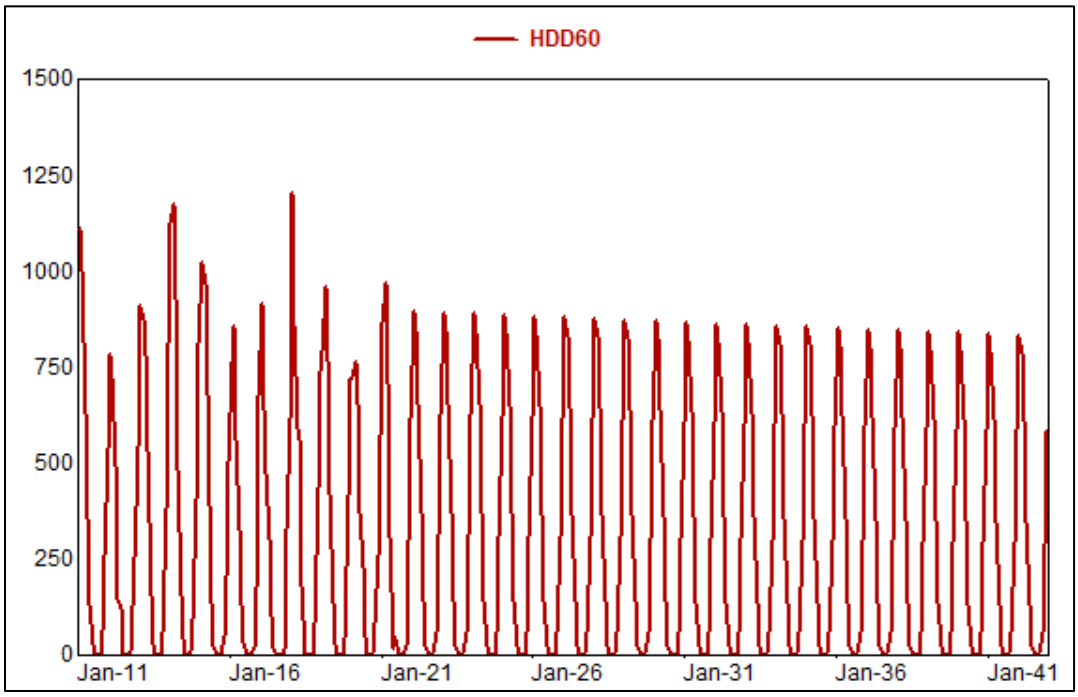
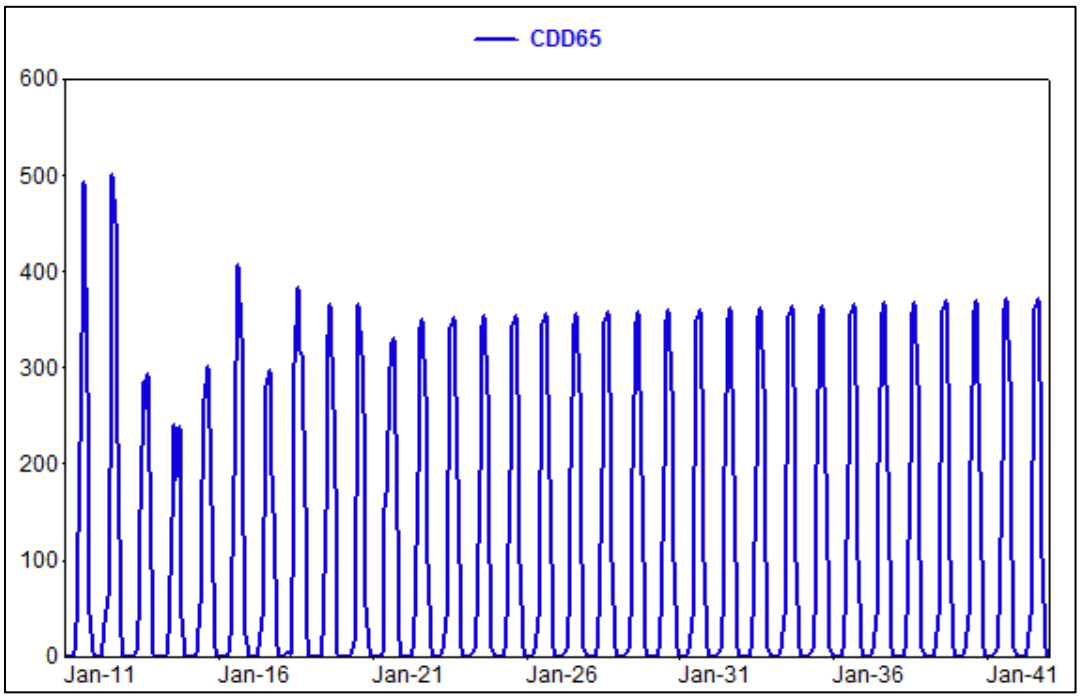


Figure 11.2 – Cooling Degree Days



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

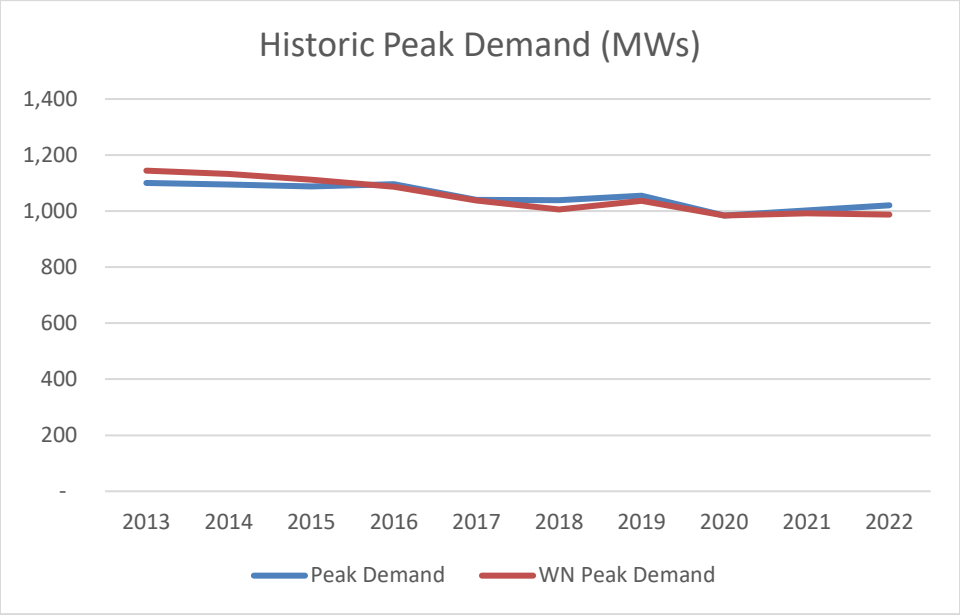
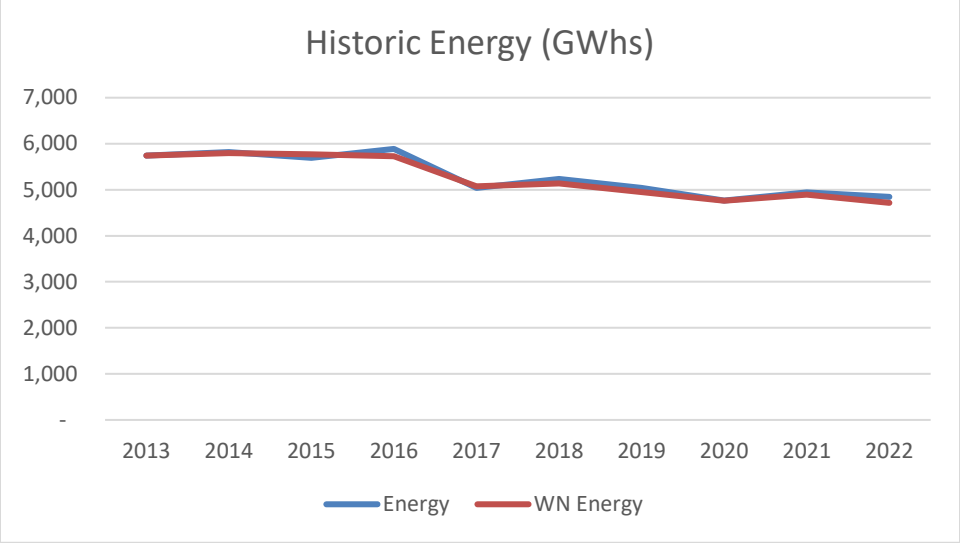


Figure 11.9 – Historic Energy



11.1.3.2 Load Shapes

Figure 11.10 – Historic Annual Load Shape

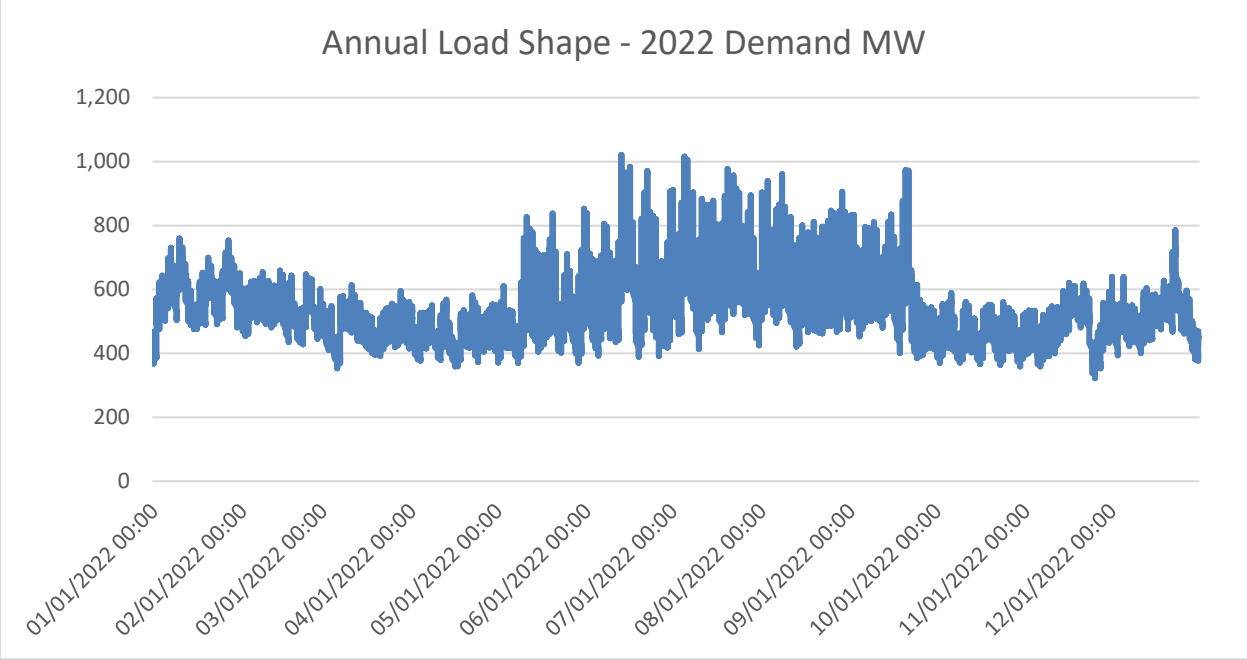


Figure 11.11 – Winter Peak Day

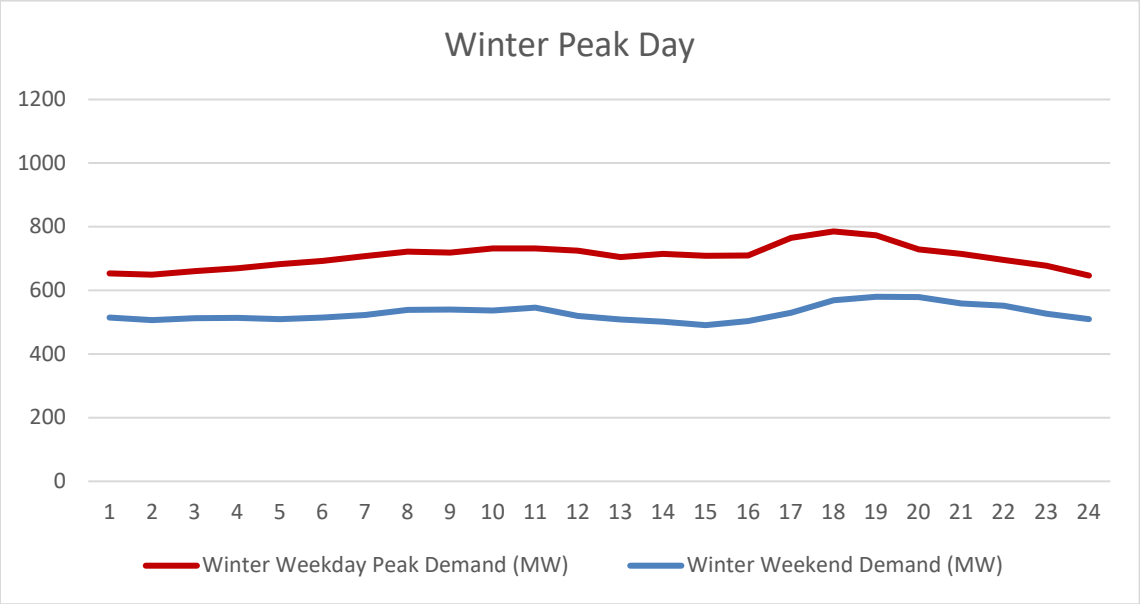


Figure 11.12 – Typical Spring Day

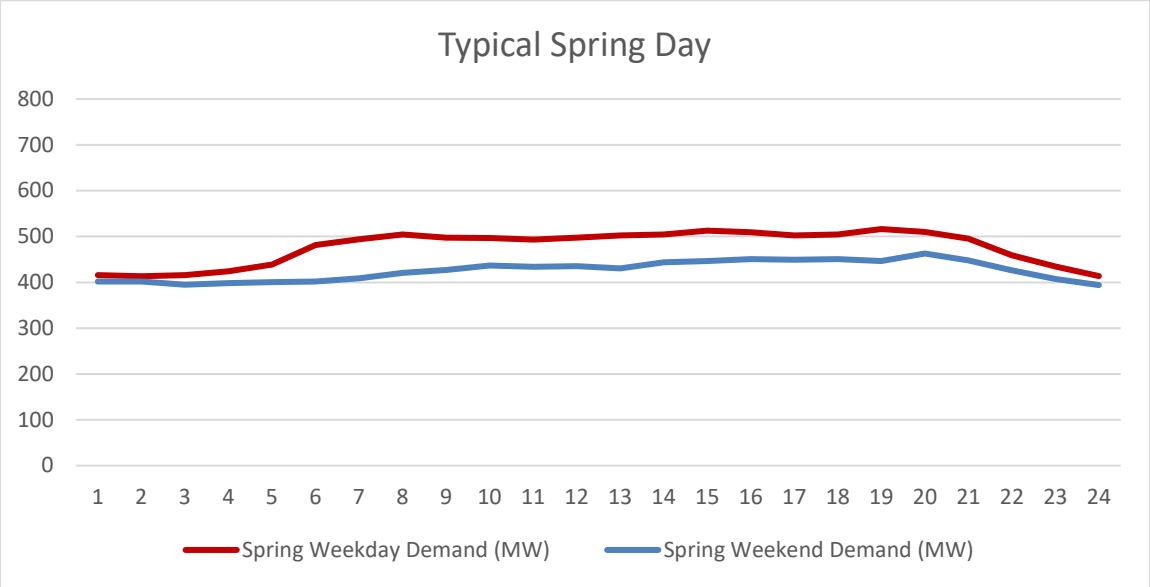


Figure 11.13 – Summer Peak Day

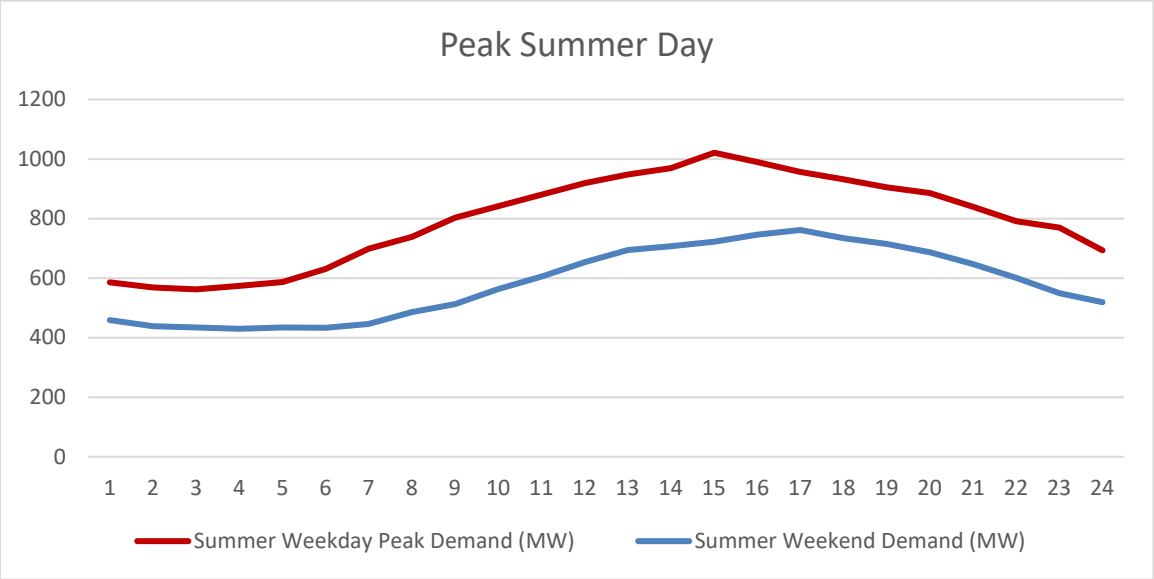


Figure 11.14 – Typical Fall Day

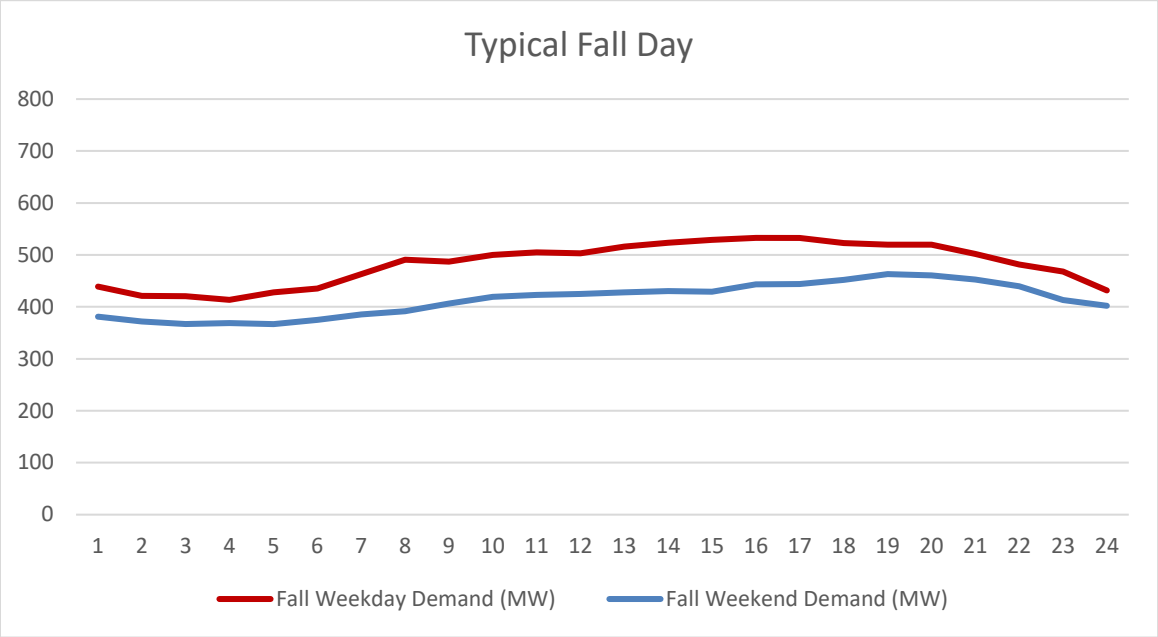


Figure 11.15 – January Load

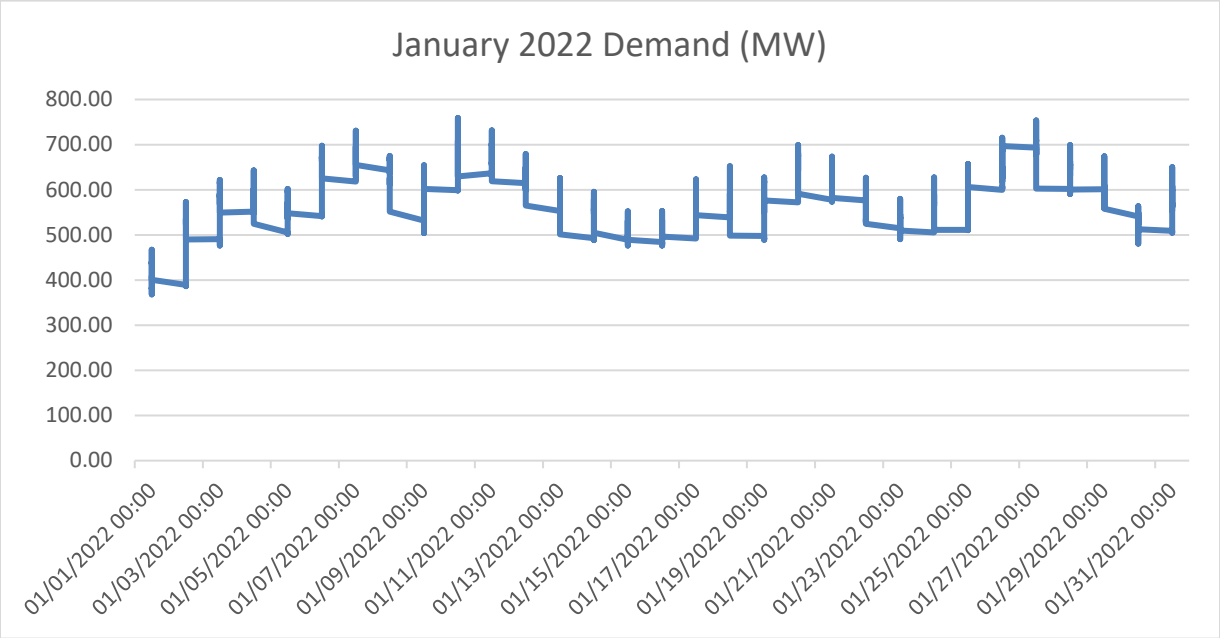


Figure 11.16 – February Load

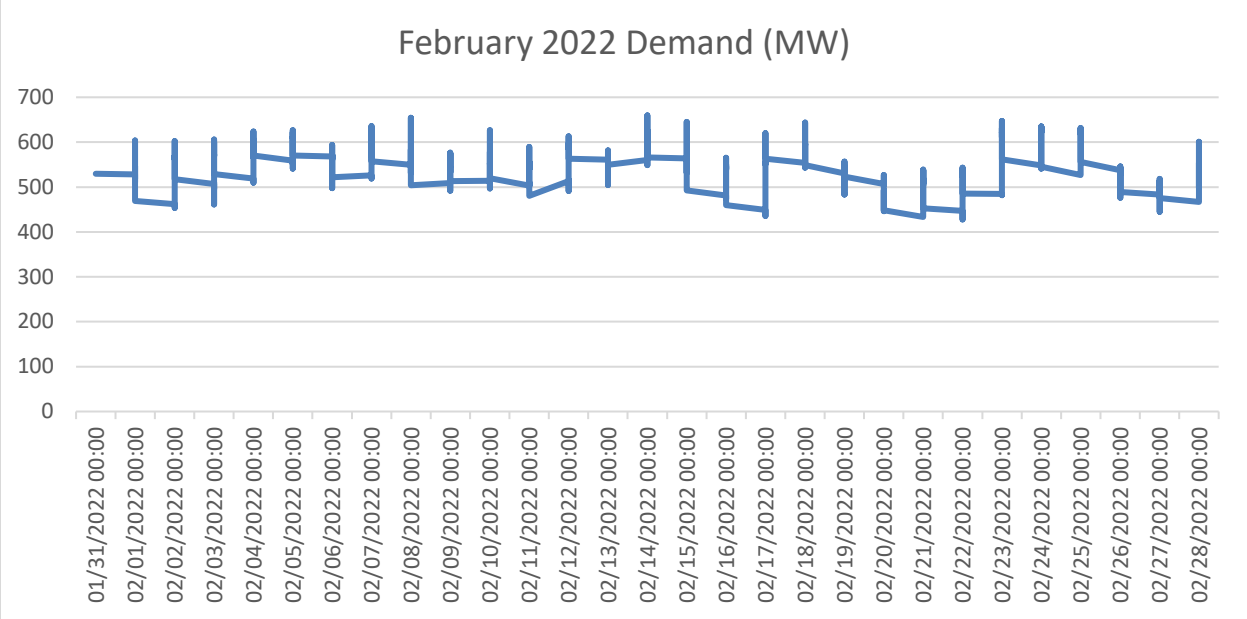


Figure 11.17 – March Load

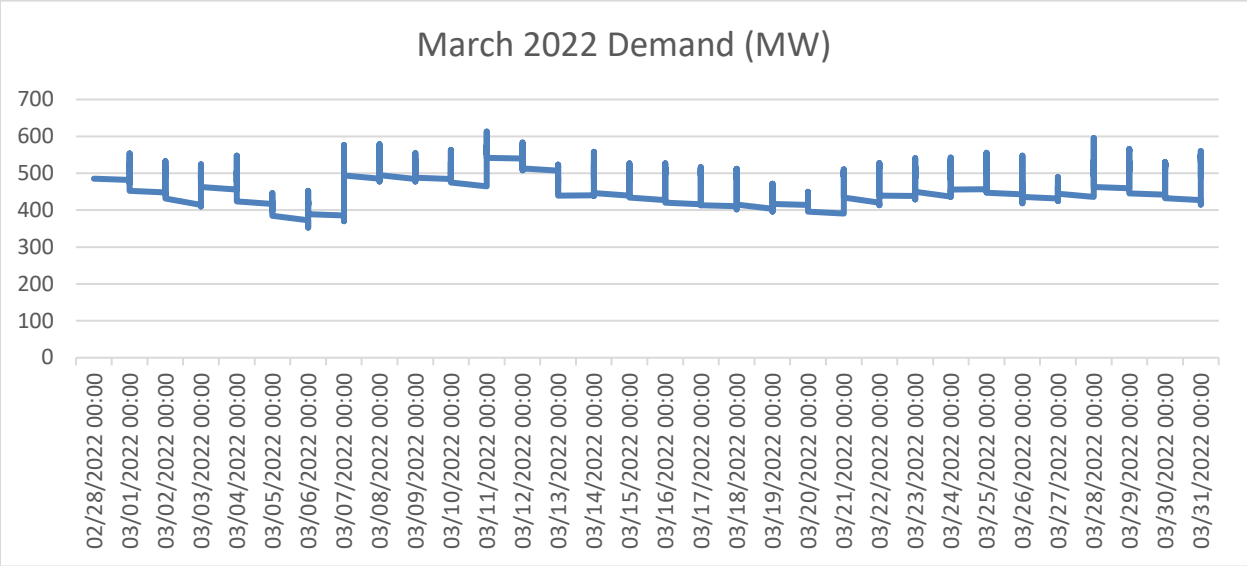


Figure 11.18 – April Load

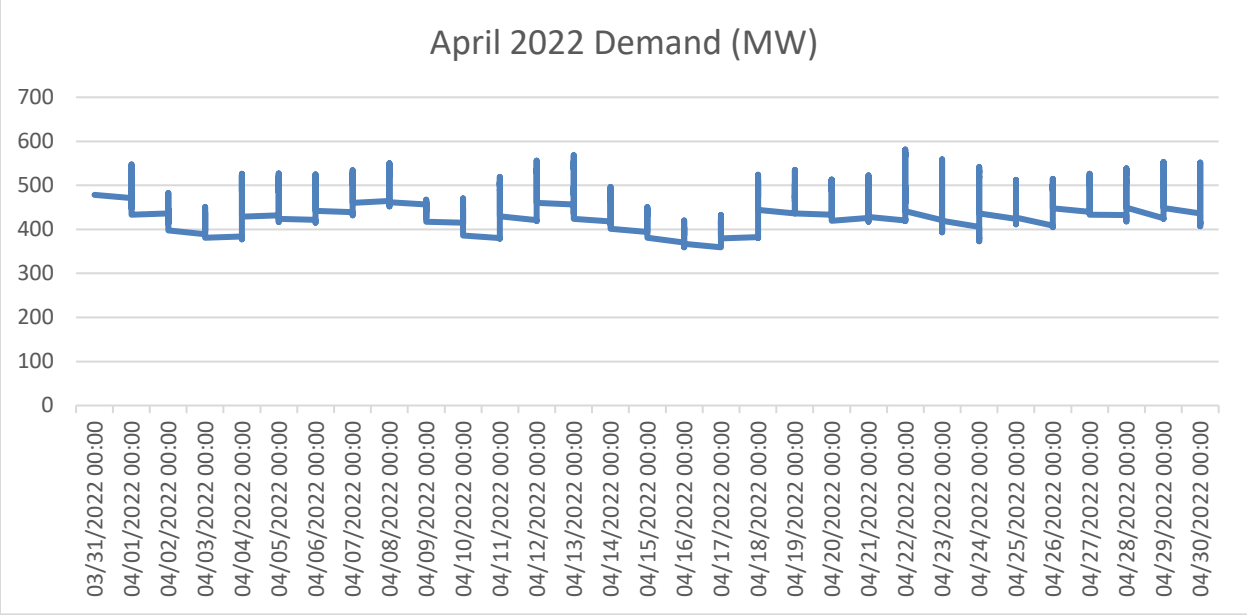


Figure 11.19 – May Load

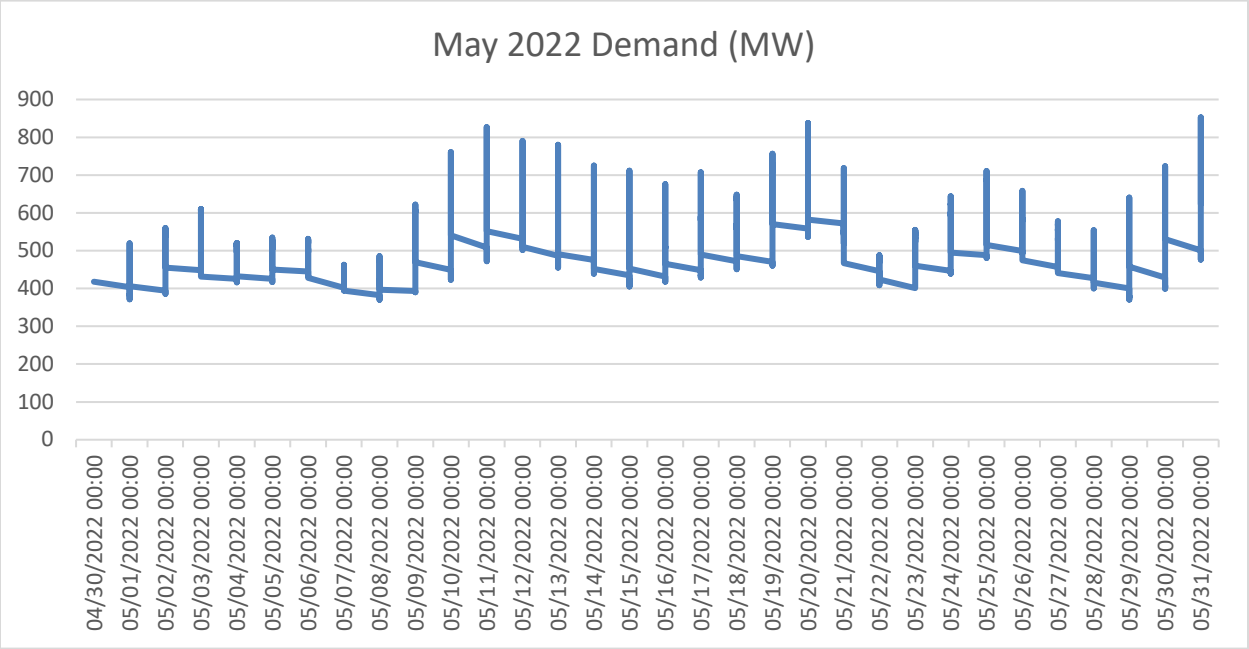


Figure 11.20 – June Load

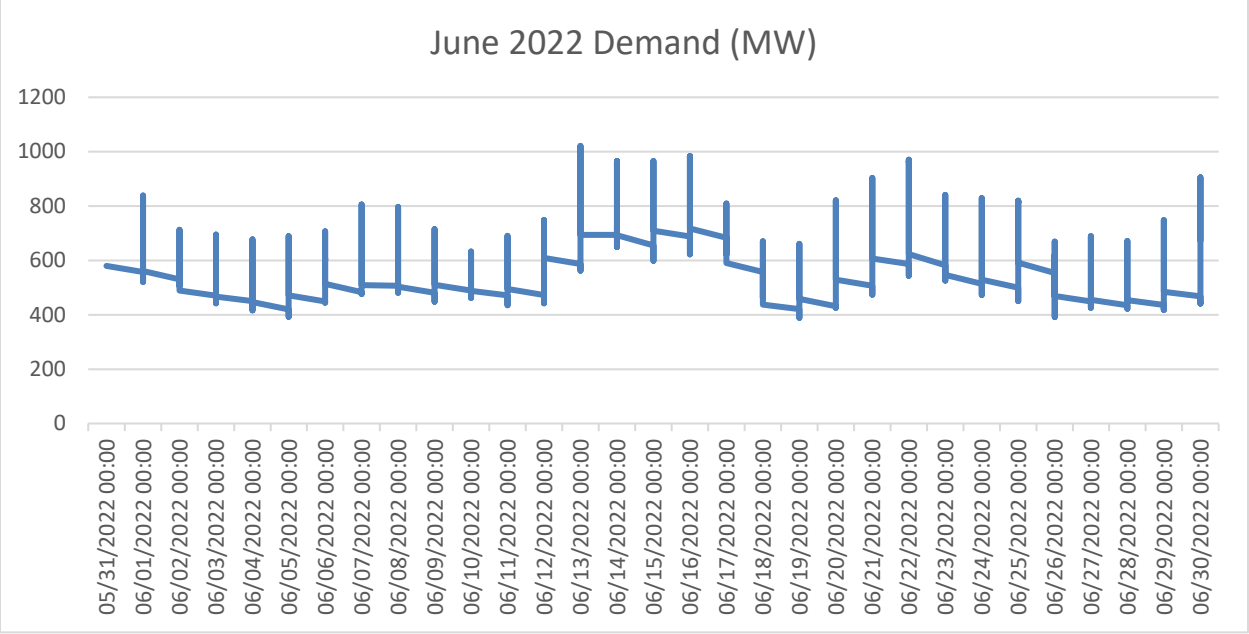


Figure 11.21 – July Load

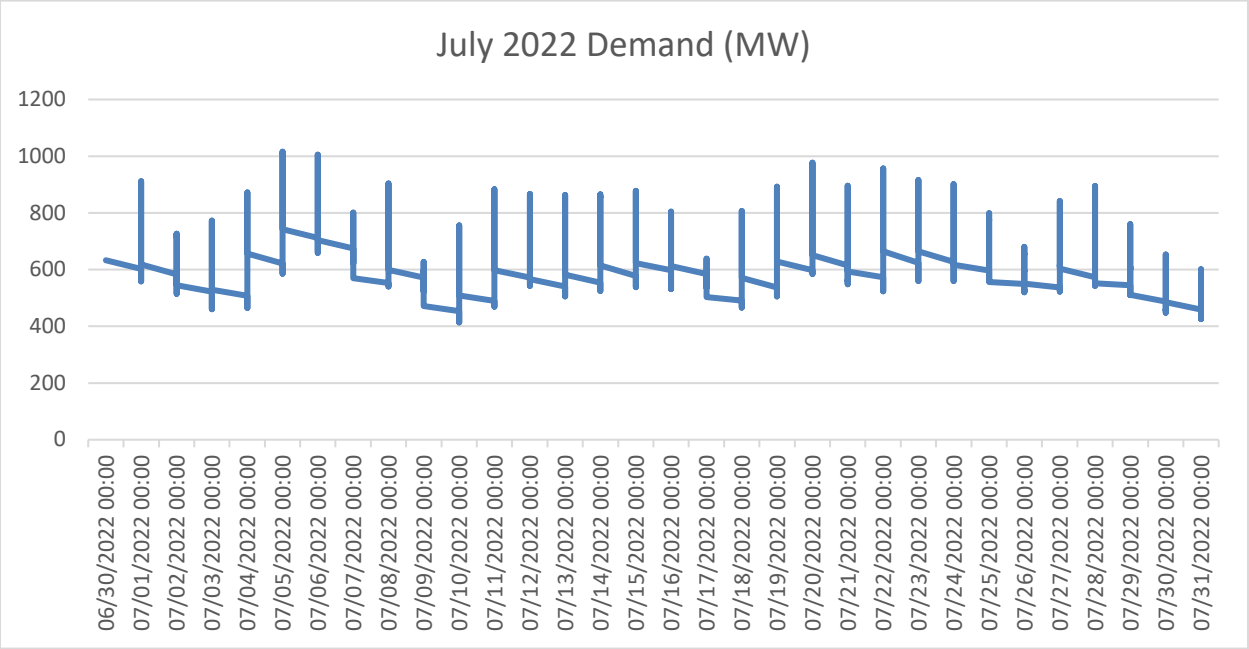


Figure 11.22 – August Load

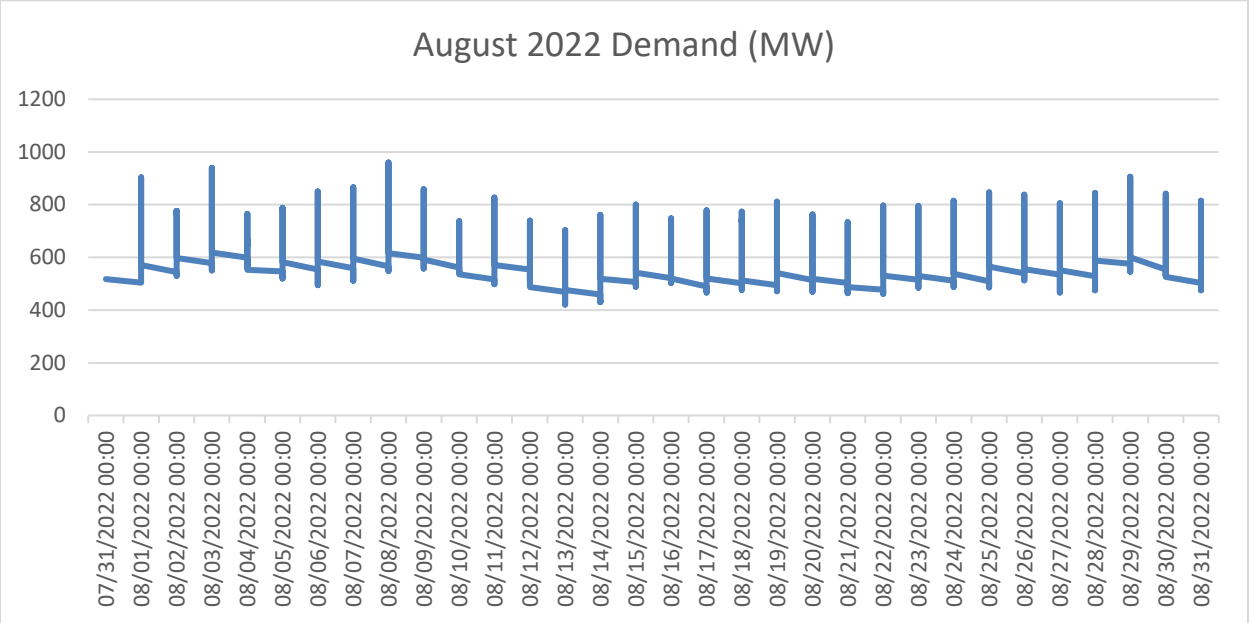


Figure 11.23 – September Load

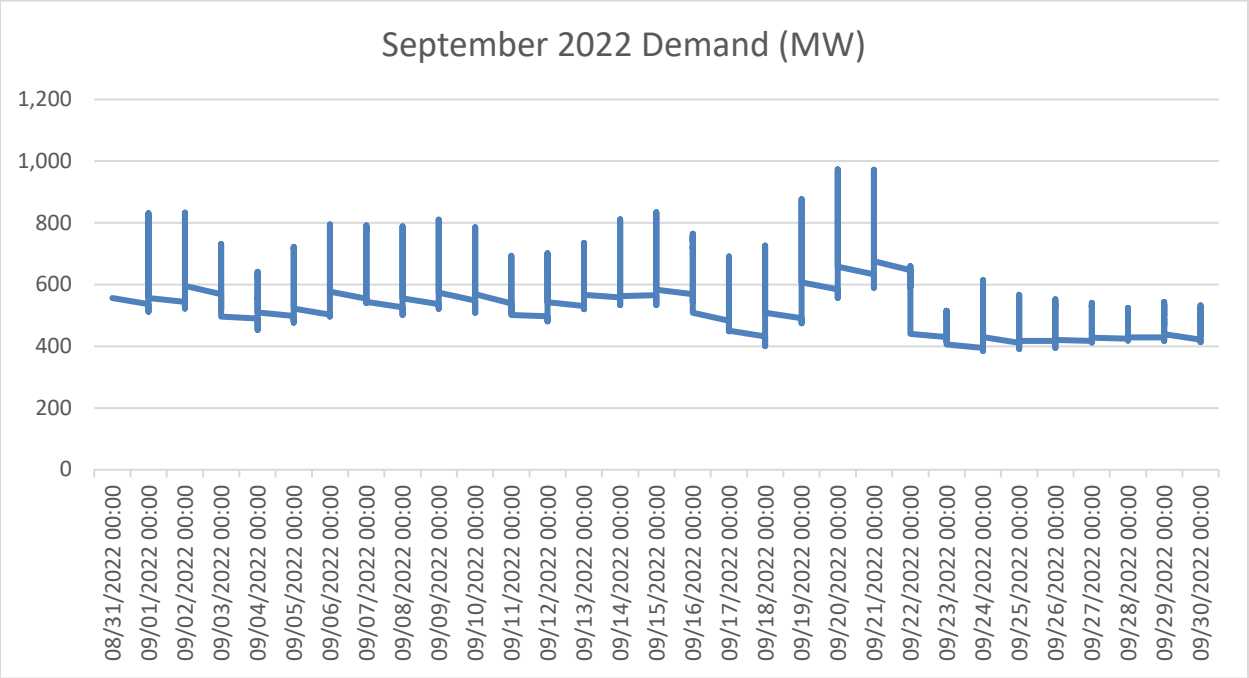


Figure 11.24 – October Load

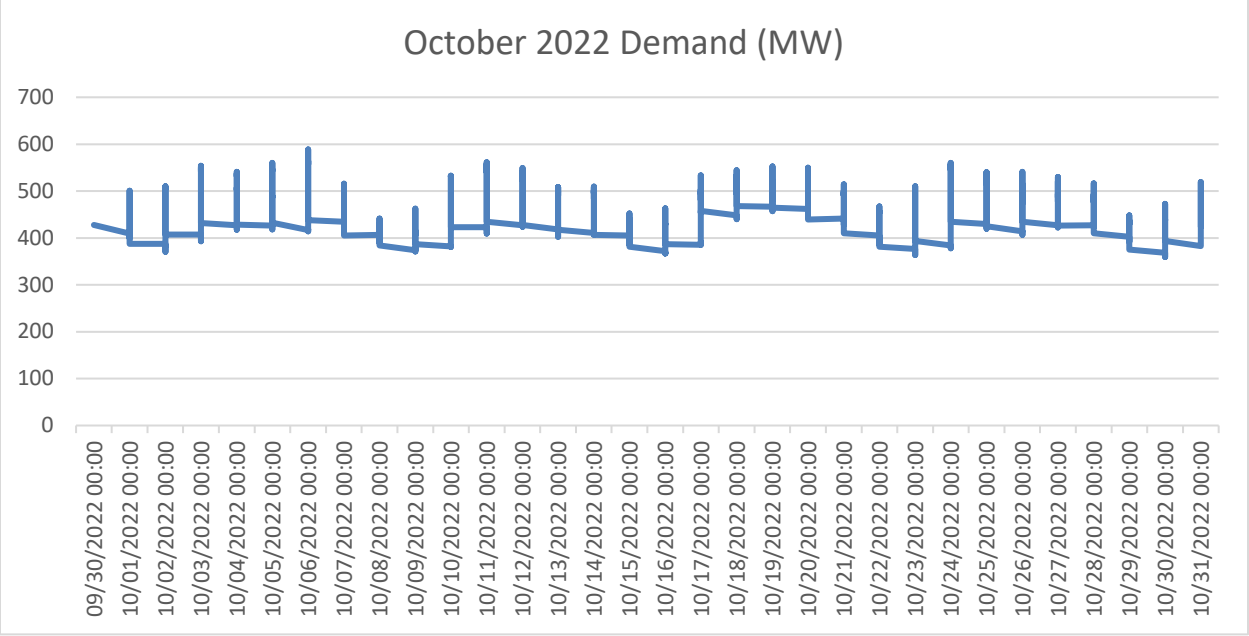


Figure 11.25 – November Load

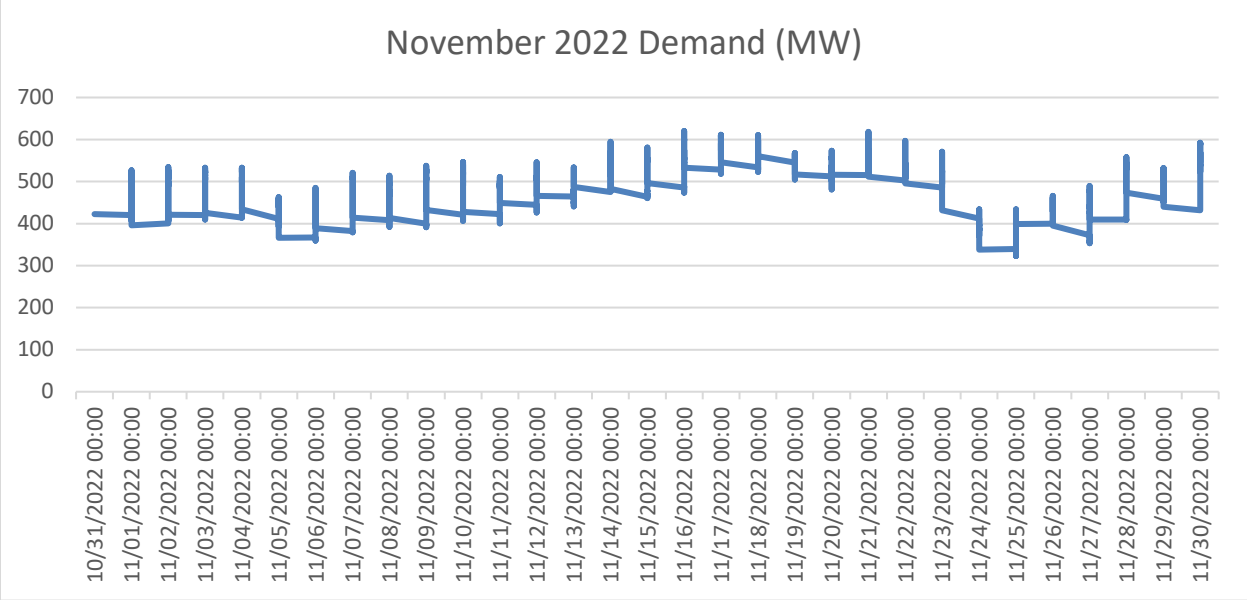
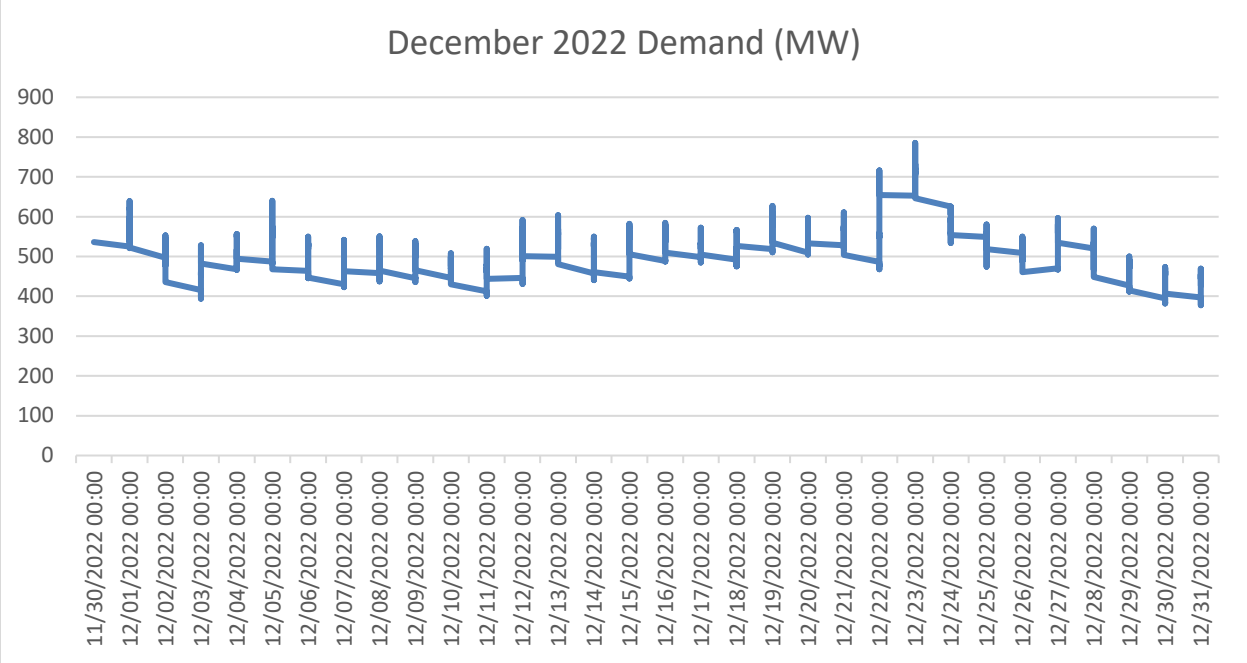


Figure 11.26 – December Load



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.

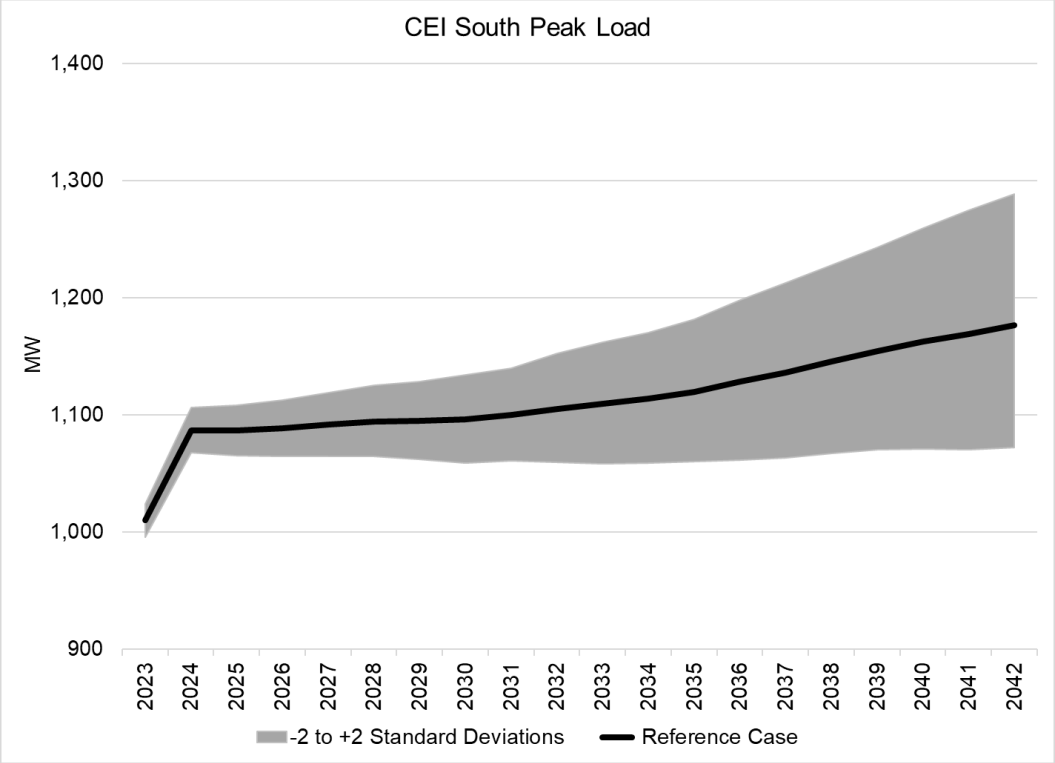
11.6 Probability Distributions

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.

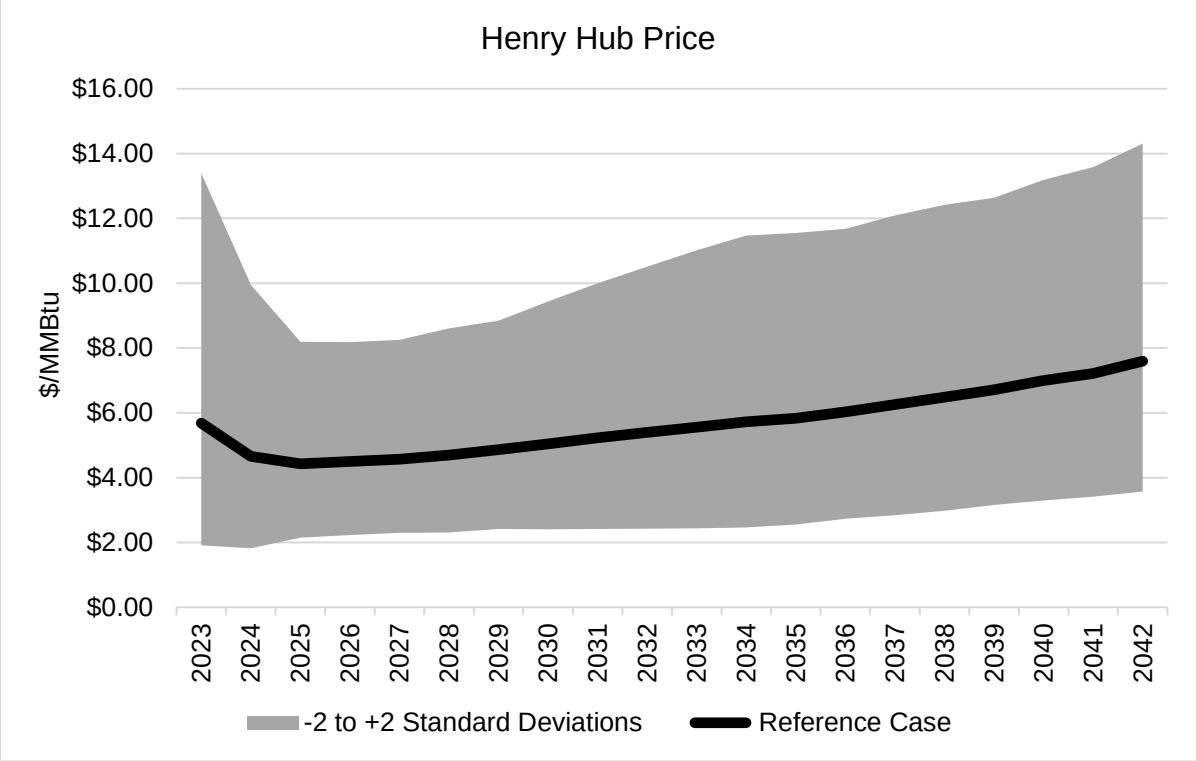
Figure 11.37 –CEI South Load Distribution (Megawatts)



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.

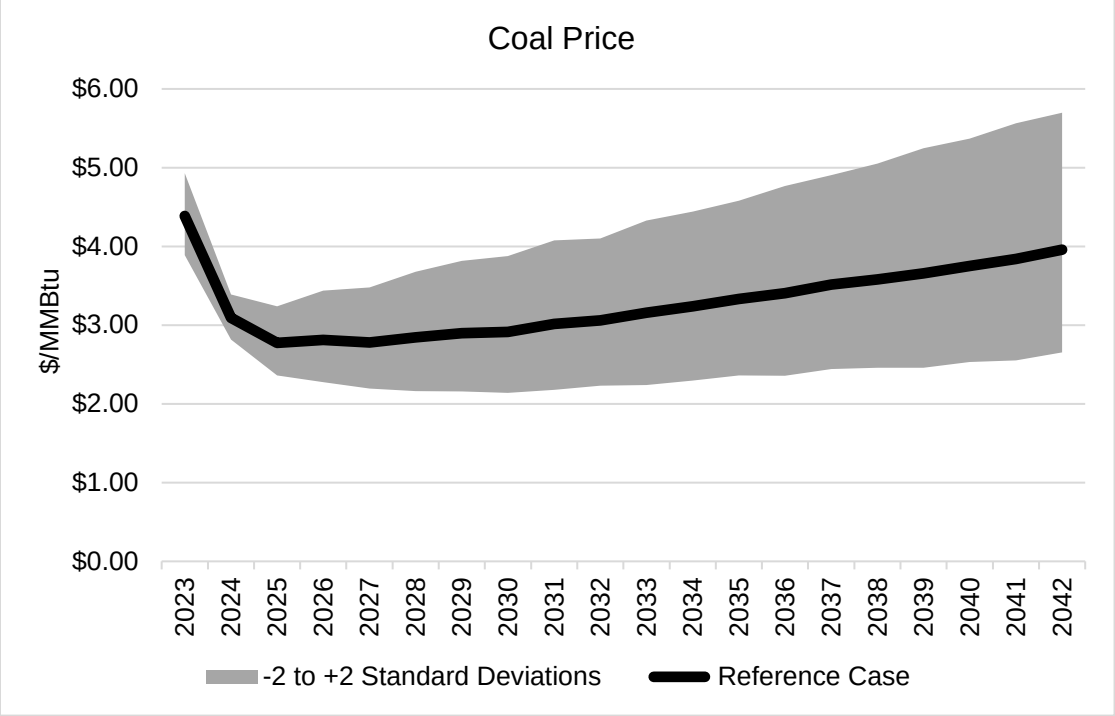
Figure 11.38 –Natural Gas (Henry Hub) Price Distribution (Nominal$/MMBtu)



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

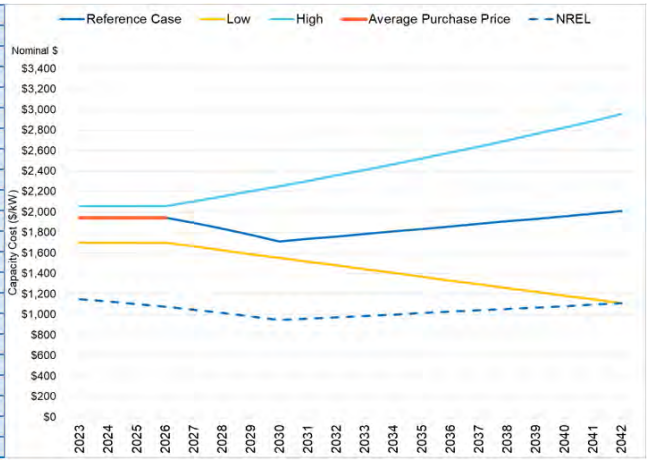


Figure 11.41– Wind Capital Costs Alternate Scenarios (200 MW) ($/kW)

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

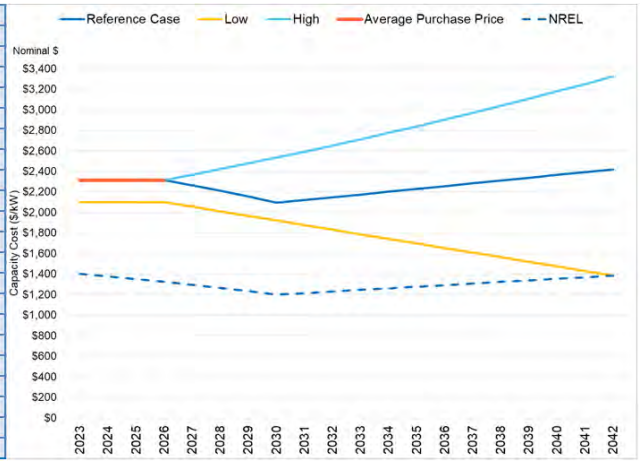
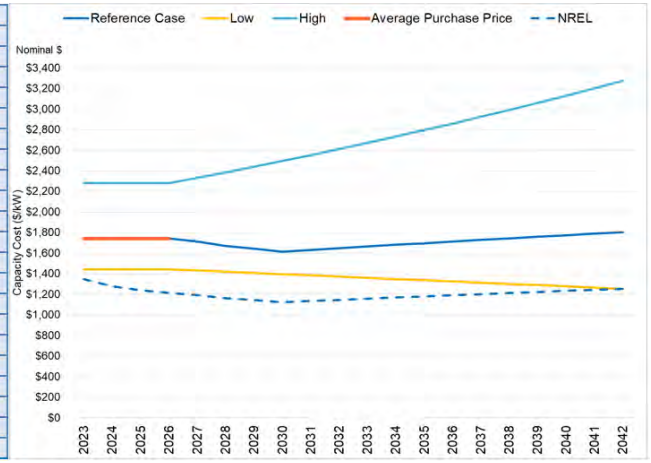


Figure 11.42– Lithium-Ion 50 MW/ 200 MWh Battery Storage Capital Costs Alternate Scenarios ($/kW)

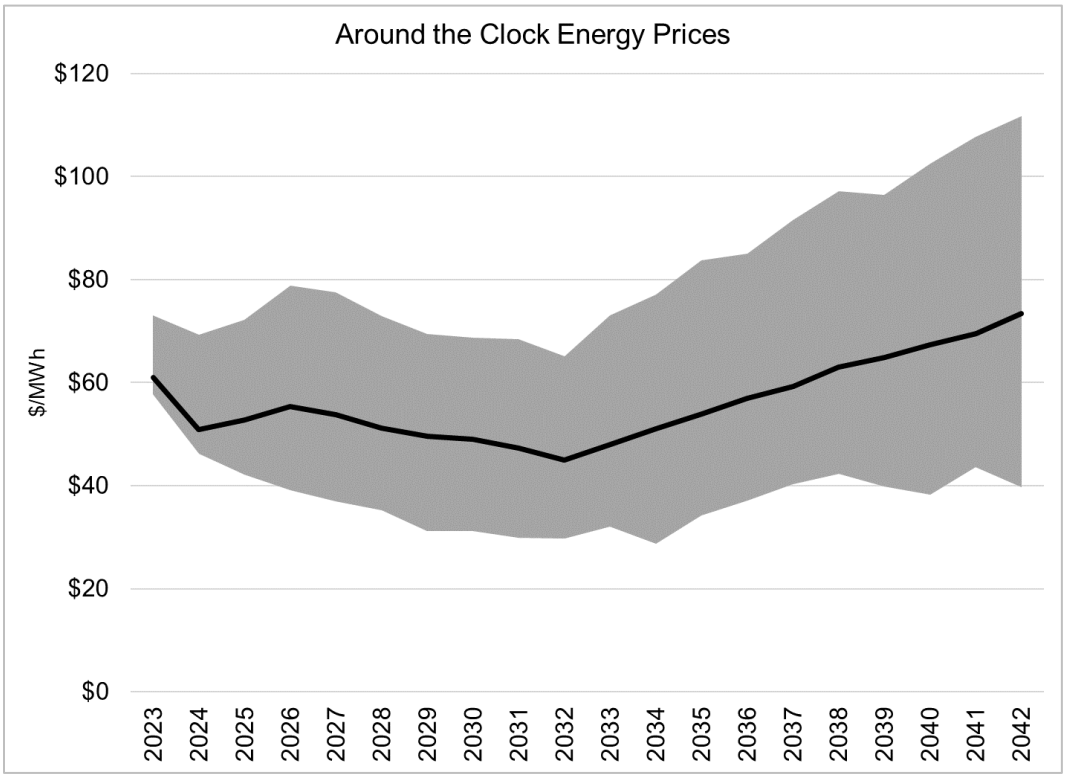
Year	Reference Case	Low	High	NREL
2022	$1,742	$1,443	$2,279	$1,434
2023	$1,742	$1,443	$2,279	$1,344
2024	$1,742	$1,443	$2,279	$1,277
2025	$1,742	$1,443	$2,279	$1,236
2026	$1,742	$1,443	$2,279	$1,211
2027	$1,711	$1,431	$2,331	$1,190
2028	$1,669	$1,419	$2,385	$1,160
2029	$1,643	$1,407	$2,439	$1,142
2030	$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

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 117
RTO Insider Article

Consumers Energy's J.H. Campbell coal plant | *Newkirk Electric Associates*

Aug 21, 2025 | John Cropley and Amanda Durish Cook

The U.S. Department of Energy has ordered the J.H. Campbell Generating Plant to remain available another 90 days, saying its capacity is needed to maintain *MISO* grid reliability.

Consumers Energy had planned to retire the 1,420-MW coal-fired facility in southwest Michigan on May 31, but DOE on May 23 issued an emergency order (*202-25-3*) under Section 202(c) of the Federal Power Act ordering it to remain ready to operate because of a shortage of electricity and capacity to generate electricity. (See *DOE Orders Michigan Coal Plant to Reverse Retirement*.)

That order expired at midnight Eastern time Aug. 21.

Energy Secretary Chris Wright issued the follow-up order (*202-25-7*) at 8:50 p.m. Eastern time Aug. 20; it expires Nov. 19.

Why This Matters

Why This Matters

The order is another move by the Trump administration to use

aging fossil generation to shore up the grid.

The order is another move by the Trump administration to use aging fossil generation to shore up the grid.

In his Aug. 20 order, Wright indicated the generation shortfall in MISO is likely to continue.

President Donald Trump *declared an energy emergency* on his first day in office, and his Cabinet agencies have been scrambling to rejigger energy policy toward the fossil fuels he favors.

One of their stated priorities has been halting retirement of aging fossil-burning plants.

In a news release, Wright cited seasonal outlooks by *NERC* and NOAA warning of high temperatures in the Midwest as well as resource adequacy projections by MISO itself.

“The United States continues to face an energy emergency, with some regions experiencing more capacity constraints than others. With electricity demand increasing, we must put an end to the dangerous energy subtraction policies embraced by politicians for too long,” he said.

“This order will help ensure millions of Americans can continue to access affordable, reliable and secure baseload power regardless of whether the wind is blowing or the sun is shining.”

Section 202(c) has been a lightly used provision historically. Just 11 orders were issued during the Biden administration, all of them weather-related. This compares with *nine by Wright since mid-May*, only one of which was weather-related.

The cost of halting the J.H. Campbell retirement has been a point of contention. (See *DOE Extension of Michigan Coal Plant Cost $29M in 1st Month* and *FERC Rules Costs of Mich. Coal Plant Extension Can be Split Among 11 States*.)

It also has been unpopular with environmental advocates.

Sierra Club Beyond Coal Campaign Director Laurie Williams *said Aug. 21*: “By illegally extending this sham emergency order, Donald Trump and Chis Wright are costing hardworking Americans more money every single day for a coal plant that is unnecessary, deadly and extremely expensive.”

Earthjustice Senior Attorney Michael Lenoff said: “Chris Wright is not a Soviet-era central planner, but his new order suggests he would fit right in. The order purports to override the considered judgment and careful work of many federal, state and regional bodies who actually have authority to keep the lights on. In their place, Secretary Wright blunders in.”

In a statement, MISO said it will “continue coordinating with Consumers Energy to comply with the order.”

But MISO again stressed that J.H. Campbell did not clear the planning resource auction and is unnecessary for resource adequacy in the 2025/26 planning year.

"MISO's 2025-2026 Planning Resource Auction indicated adequate resources to meet anticipated demand. State regulators along with utilities have the responsibility of ensuring resource adequacy. MISO remains focused on reliably operating the grid using the resources our members provide, while working closely with stakeholders and regulatory partners, providing visibility into system needs and sending market signals to inform long-term resource planning," MISO spokesperson Brandon Morris said in a statement to *RTO Insider*.

MISO leadership previously has said it might have to navigate similar future orders from the federal government to prop up retiring coal plants.

MISO Director Todd Raba said MISO might have to navigate similar edicts in the future, with about 30 coal plants in the footprint. At MISO's June board meeting, he said it's a "critical topic that will have huge implications in MISO."

Lawmakers, health professionals and other officials ***gathered*** near the plant in West Olive, Mich., on Aug. 12 to protest its extension. On Aug. 18, a small crowd of community members marched to U.S. Rep. Bill Huizenga's office in nearby Holland, Mich., to again protest continued operations.

Consumers Energy said it was evaluating the order extension and expects to "continue operating the plant as required by DOE."

"We have worked closely with MISO and have been operating in compliance with the order and MISO's dispatch requirements. All power generated by the Campbell plant and other Consumers generating plants is supplied to the MISO grid. Specific details on recent generation are not publicly available at this time," spokesperson Brian Wheeler told *RTO Insider*.

Wheeler also said the utility was "pleased" with ***FERC***'s approval of an allocation that's set to disburse cost recovery of the plant among the 11 states or portions of states in MISO Midwest.

Consumers Energy declined to comment on the coal plant's usefulness so far over the summer or how the plant will fit into the MISO market over the fall.

Data from power analytics company Yes Energy shows the 1.42-GW plant has been used consistently since the beginning of August, averaging an 84-88% hourly capacity factor.

COAL | RELIABILITY | RESOURCE ADEQUACY

KEYWORDS CHRIS WRIGHT | CONSUMERS ENERGY | FEDERAL POWER ACT SECTION 202 (C) | J.H. CAMPBELL PLANT | MIDCONTINENT INDEPENDENT SYSTEM OPERATOR (MISO) | U.S. DEPARTMENT OF ENERGY (DOE)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 118
RMI Analysis of Coal Plants' Threats to Reliability

Reality Check: We Have What's Needed to Reliably Power the Data Center Boom, and It's Not Coal Plants

A range of clean, resilient solutions can help us meet the electrical needs of our growing digital economy while saving Americans money.

August 12, 2025

By Gabriella Tosado, Ashtin Massie, Joe Daniel

After decades of relatively flat electricity demand, the US power sector is expecting demand to grow due, in large part, to new data centers. These energy-intensive facilities are reshaping the grid, with some utilities now projecting over 20 percent load growth by 2035. In places like Virginia, which constitutes 13 percent of all reported data center capacity globally and 25 percent of the data center capacity in the United States, data centers already account for over a quarter of some utilities' total electric demand, and their footprint is only growing.

The myth

Utilities are struggling to maintain accurate forecasts and identify resources that can meet this growth. There is a high-profile effort to keep coal plants that are set to retire online and run them at unprecedented levels, ostensibly for reasons of reliability. But the truth is, coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

> Coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

Tweet

Reality #1: Aging coal plants are failing to consistently deliver under stress

Coal plants face a fundamental constraint: they are aging and increasingly unreliable. Most of the coal fleet was built in the 1970s and 1980s, and years of wear and tear have led to a rise in unplanned outages. In many cases the sheer cost to maintain and modernize these plants did not make sense with the availability of more reliable and affordable alternatives – and that's still the case.

According to the Energy Systems Integration Group (ESIG) *Ensuring Efficient Reliability* report, a coal plant's capacity accreditation, or the amount of time it can contribute to peak demand, is only 83 percent when adjusted for real-world performance. PJM also has capacity accreditation of coal plants at 83 percent and some plants fare even worse. Gridlab's reliability study found Colstrip, a large regional coal plant in Montana, operating with a capacity accreditation of only 54 percent – meaning it's effectively unavailable nearly half the time it's needed.

Extreme weather exacerbates these vulnerabilities. Cold snaps, heat waves, and storms have all exposed coal's fragility during grid stress events. Reliability is not just about being dispatchable, it's about delivering performance under stress. Coal plants struggle to do that consistently. For coal plants to truly meet the constant demands of data centers, they would need to run at high-capacity factors and avoid major outages, all of which fly in the face of current performance trends. If a large coal plant trips offline while supporting a cluster of data centers,

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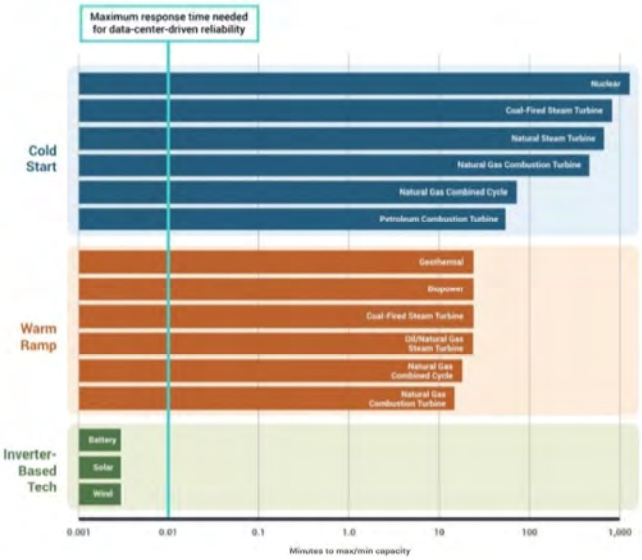
the sudden loss of supply could lead to cascading failures across the grid. This is because generation must equal load at all times, datacenter or no datacenter. As a result, relying on coal plants to support these high-density digital loads doesn't enhance reliability, it endangers it. And it's not a matter of *if* the coal plant will fail, but *when*.

Reality #2: The inflexibility of coal plants risks grid stability

Coal boosters often point to the "always-on" nature of coal plants as evidence of their reliability. But that characteristic is a liability, not a strength, when it comes to supporting large, fast-changing loads like data centers. Coal units are inherently inflexible: they ramp slowly, respond poorly to sudden load shifts, and are difficult to turn on or off quickly. This rigidity is a poor match for the dynamic and often unpredictable nature of data center demand. Further, inflexible coal plants can worsen grid congestion; by occupying limited transmission capacity with inflexible generation, they prevent cheaper or cleaner resources from being delivered. This issue has already been flagged by **independent market monitors** in regions like MISO – which covers 15 US states and a Canadian province – where congestion-related market distortions have cost **over $1 billion a year**. Coal plants displace faster-responding resources that are better suited to follow load. And the stakes are high.

As noted by the North American Electric Reliability Corporation (NERC), large, voltage-sensitive loads like data centers require flexible, responsive grid solutions, not slow-ramping generators that can take 12 or more hours to come online. NERC's recent ***Incident Review and Guidance on Voltage-Sensitive Large Load Integration*** describes an event in 2024 where a transmission fault triggered a sudden disconnection of 1,500 megawatts of voltage-sensitive data center load, leading to sharp frequency and voltage spikes that required operator intervention. The incident exposes the system's vulnerability to instability when inflexible generation cannot respond to large load fluctuations.

Minutes needed for a power plant to reach max/min capacity



If a data center either loses access to load or goes offline rapidly, a grid's generation needs to respond at sub-second speeds. The average coal plant ramp rate is **4 percent per minute** which translates to spending over 20 minutes to respond to a large load event. From a cold start, the average coal plant would take over **12 hours** to reach max capacity. Coal plants simply can't respond fast enough to support the reliability needs of modern data centers. Whether it's the hours-long startup time from a cold state or sluggish ramp rates to turn off, these plants are too slow to provide the real-time flexibility required during sudden load changes or outages.

Reality #3: Clean resources are available now that can better respond to and support data centers for less

The good news is that we don't need to rely on brittle coal plants to meet the needs of a digital economy. A range of cleaner, more resilient solutions is already available – and scalable. For example, we recently found that **more than 95 percent** of future demand can be met with fast, scalable, and clean solutions:

Shares

Alternative near-term solutions to meet load growth

Technology	Opportunity
Energy Efficiency	Over 50 GW of energy efficiency can be deployed – by both creating programs for new loads and expanding existing programs aligned with system needs. Energy efficiency can unlock benefits beyond system cost savings, improving comfort and resilience in homes.

Virtual Power Plants	60 GW of virtual power plants can be deployed by 2030, with programs stood up and enrolled in under 6 months. Policymakers in Virginia recently passed a bill that requires 450 MW of VPPs deployed rapidly to meet growing demand.
Advanced Transmission Technologies	Grid enhancing technologies and reconductoring can unlock over 80 GW of incremental peak capacity by reducing transmission and interconnection constraints. Lawmakers in New Mexico passed a bill requiring utilities to assess the use these technologies in plans to get more out of the existing grid.
Clean Repowering	There is 14 GW of fossil-fuel generation expected to retire, that could serve as sites for quick addition of new renewable energy and storage while reducing system costs. Market operators like PJM are enabling clean repowering by updating rules to allow for surplus interconnection.
Power Couples	New load can be co-located with renewable energy at the site of existing, underutilized generators with approved interconnections—a strategy which we call "Power Couples." There is over 30 GW of opportunity to deploy Power Couples under $100/MWh, and over 50 GW of opportunity under $200/MWh.

Coal plants are a legacy technology, not a solution for the future. Coal plants' operational characteristics make them less suited to meet the scale and speed of these new challenges. The path forward is not about discarding the past, but about building on it with cleaner, more adaptable resources that can reliably serve evolving grid needs.

Technologies like battery storage, demand flexibility, and clean energy portfolios offer practical, cost-effective options that align with modern load dynamics. As we noted in a recent **article**, by running coal plants only when it is economical to do so and using the extra transmission headroom that creates to reinvest with clean energy upgrades, our grid can support the next wave of economic growth with the flexibility it demands. There are reasons to manage the shift to new, clean resources **thoughtfully and intentionally**, but propping up coal plants that are not suited for the job is a step in the wrong direction.

RECOMMENDED READING

Gas Turbine Supply Constraints Threaten Grid Reliability; More Affordable Near-Term Solutions Can Help

June 18, 2025

Read More

Reinvesting at Coal Plant Sites with Clean Energy Upgrades Supports both Reliability and Affordability

July 16, 2025

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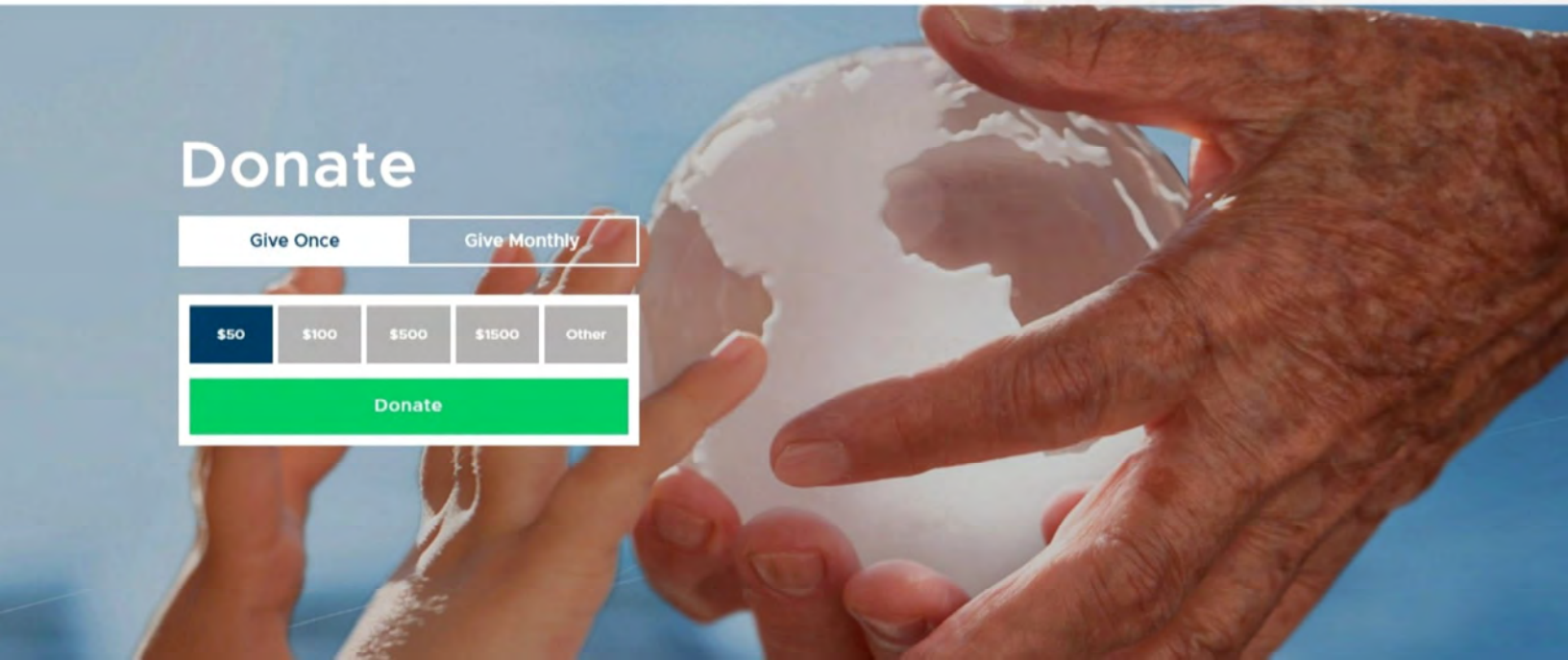

Solutions Can Help

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Affordability

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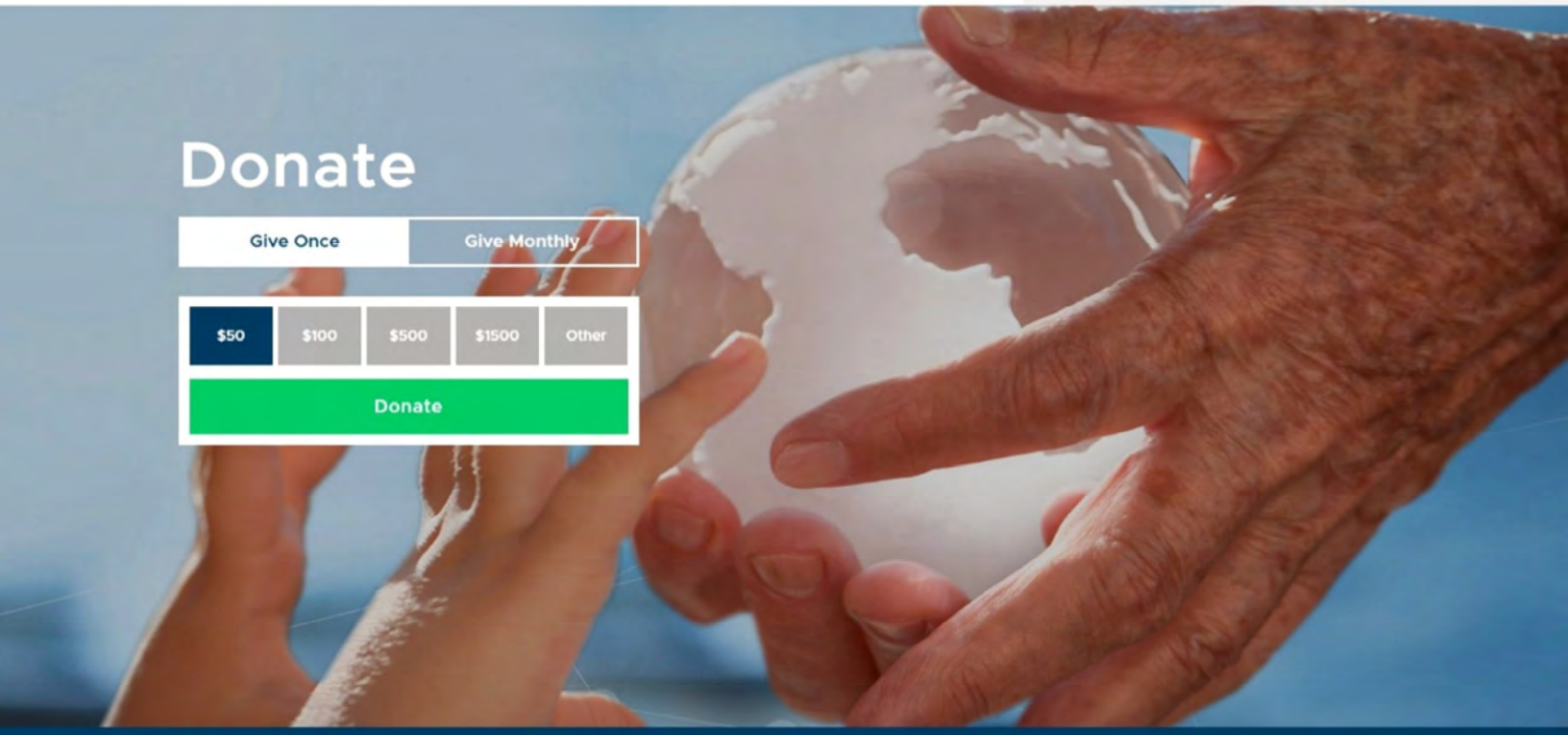

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Exhibit 119
MISO, ZRC Replacement Guidance

ZRC Replacement and instructions in the MECT

RASC

05/24/2023

Presentation updated as 7/11/2023
Updates are at the end of the deck Slides 12-17

Presentation updated as of 9/29/2023
Updates are on slides 14 & 17

Purpose and Key Takeaways

Purpose:

Provide Stakeholders with information and training on ZRC replacement in the MECT

Key Takeaways:

- ZRC replacement uses, and process explained and clarified
- ZRC replacement does not impact settlements from the PRA
- ZRC replacement is used for suspension, retirement, Catastrophic Generator Outage or full or partial Generator Planned Outages that may exceed thirty-one (31) Days in the Season
- MECT User Guide has additional detail

Reasons to use ZRC Replacement

- Generators that have cleared a season(s) in the PRA that go on suspension, retirement or Catastrophic Generator Outage
- Cleared ZRCs for resources with planned generator outages and/or derates in excess of 31 days in a season
- ZRC replacement must overlap the suspension, retirement, catastrophic outage or outages/derates of the cleared generation being replaced
- Resources ZRCs cannot be replaced other than for the reasons listed above

31-day rule Capacity Replacement Clarification

ZRC Replacement FAQ

- ZRC replacement substitutes the Resource Adequacy Requirement (RAR) and Must Offer Obligation for the cleared resource

- Fully replaced resources (>95% cleared ZRC) will be granted Tier 1 & 2 exemptions during the replacement hours from Schedule 53 SAC calculation
  - Exemptions are for SAC calculations only, still subject to the capacity replacement rules and penalties
  - Exemptions for derates is still under discussion

- ZRC replacement does not impact settlements from the PRA, however resources that failed to meet the replacement requirement will incur non-compliance charges

Process for ZRC Replacement

- Use the "Replacement Calculator" on the MECT
- Obtain the ZRCs used in the replacement
- Submit the replacement on the "Resource Substitution" screen in the MECT
  - ZRC replacement should be entered into the MECT at least 7 calendar days prior to the effective date of replacement
- Contact MISO with any issues through the MISO help center

Use Replacement Calculator

- The Replacement Calculator is to verify that the prospective replacement ZRCs do not violate LCR, CIL or CEL for each zone when using ZRCs from another LRZ or ERZ

Zonal Data	PRMR (Obligation)	Offers Cleared + FRAP	LCR	Import Level (CIL)	Export Level (CEL)	Auction Import	Auction Export	Replacement Import	Replacement Export	Import Available	Export Available
1	18374.9	18661.2	16588.7	3754.0	3373.2	0.0	286.3	0.0	0.0	4040.3	3086.9
2	13449.9	13536.9	13017.5	1714.0	978.7	0.0	87.0	48.1	22.0	1774.9	917.8
3	9882.0	10391.1	7960.2	2896.0	4589.7	0.0	509.1	0.0	0.4	3405.5	4080.2

CALCULATE RESET

Calculator	Total MW needing replacement	Replacement ZRCs from the same zone	ZRCs from same zone after replacement	LCR test	Total Import Amount Needed	Amount Exported	Import Test	Export Test
1	200	100	18561.2	PASS	100	0	PASS	
2	0	0	13470.8	PASS		40		PASS
3	0	0	10331.5	PASS		60		PASS
4	0	0				0		

More information can be found in the MECT User Guide in section 31 & 32

Obtain the ZRCs

- Market Participants will need the un-cleared ZRCs to use in the ZRC replacement
  - This can be from their own un-cleared ZRCs
  - This can be from a ZRC Transaction
    - Non-MISO Bulletin can be utilized to find ZRCs from other Market Participants

More information can be found in the MECT User Guide in section 18

ZRC Replacement in the MECT

- Navigate to the “Resource Substitution” screen in the MECT, fill in the form and submit

More information can be found in the MECT User Guide in section 30

Next Steps

- MECT release at the end of May will include an “end date” for ZRC replacement”. When the replacement is completed the ZRCs will be repopulated to the resource

- Additional details and screenshots will be added to this presentation and the MECT user guide and both will be reposted

Bullet point 3 updated on 7/12/2023

References

- MISO Resource Adequacy BPM-011-r27
  - Section 6.4, “Replacement Resources”
- MISO Tariff Module E-1
  - Section 69A.3.1.h, “Retirement, Suspension and Replacement of Planning Resources”
- MECT User Guide
  - Sections 18, 30, 31 and 32

https://help.misoenergy.org/support/

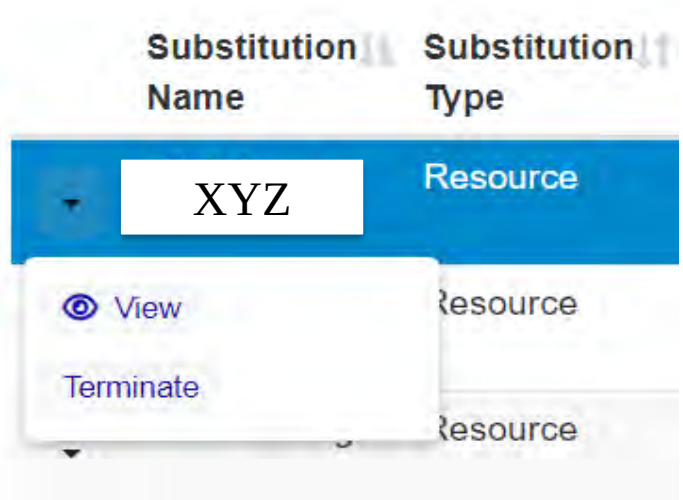
Additional Content added as of 7/11/2023

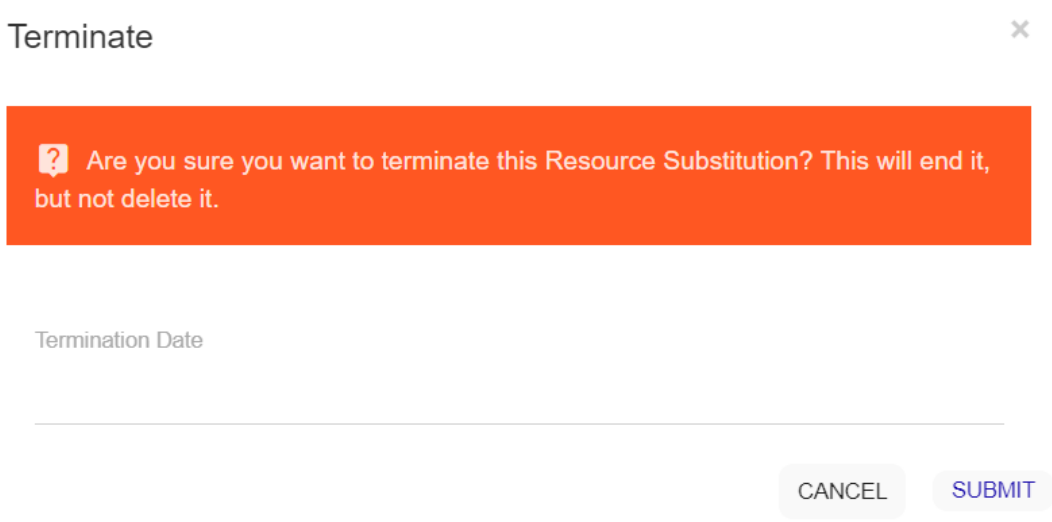
BPM-011-r28 updated and posted to MISO website

- BPM-011-r28 has been posted to MISO website with clarification to sections 6.4.3 – 6.4.7
- Updates are limited to ZRC Replacement and implementation and assessment of the 31-day rule

Updates to the MECT allowing ZRC Replacement Termination

- Resource Substitution defaults to the end of the season
  - Before the effective date, a new dropdown will allow MPs to delete the substitution
  - After the effective date, a new dropdown will allow MPs to terminate the ZRC replacement between the effective date and current date





Scheduling 31+ day Generator Outages and participation in the PRA

- For resources that have anticipated planned outages that last longer than 31 days in the next Planning Year, the following options are available
  - Straddle seasons, if the resource has a planned 50-day outage, having 25 at the end of one season, continuing for the other 25 days into the subsequent season
  - If the outage is long enough, the resource could plan the outage during one season and not offer into the PRA for that season (requires working with the IMM). During the time the resource is available in the season, they could provide ZRC replacement for other resources
  - Work with the IMM to factor in the 31-day penalty price into the offer for the PRA, which can exceed the FSRL limit ~$25-30/MW-day

31-day Outage Rule (1 of 2)

- MISO's Control Room Operations Window (CROW) includes the following 4 categories of out of service (OOS) and derates: Planned, Urgent, Emergency and Forced. For purposes of calculating CRNCCs, MISO will use CROW outages prioritized as Planned. In addition, all outages not prioritized as Planned in CROW, but that were: (1) known or reasonably known at the time of the PRA, or (2) were determined by the IMM to be incorrectly prioritized in CROW shall be included in calculation of the CRNCC. See BPM-008 and the CROW users guide for outage prioritization codes and definitions. must replace ZRCs or incur a CRNCC penalty cost.
- Capacity non-compliance charge as stated in section 6.4.7 of BPM-011-r28 is equal to the # of days greater than 31 that did not properly replace * # of ZRCs * (seasonal ACP + daily Zonal CONE)
  - For example. A 100 MW resource in LRZ5 for Summer 2023 ($10 ACP) that was on a planned outage for 35 days and did not replace any ZRCs would incur the following charges
    - 4 days * 100MW * (10 + 300.2) = $124,080
- The ZRC replacement and penalties are assessed and applied to the Market Participant who converts SAC to ZRCs

31-day Outage Rule (2 of 2)

- The 31-day rule will be implemented on an hourly basis as laid out in section 6.4.7 of BPM-011-r28 (31 days * 24 hours = 744hours)
- CROW has 4 outage types

Forced – already out at time of submission	Not counted
Emergency – 0 to 2 days in the future	Not counted
Urgent – 2 to 14 days in the future	Not counted*
Planned – 14 days + in the future	Counted

- The hours of planned outages across the season per resource will be summed up from most ZRCs to least ZRCs, the 31 days will apply to the most severe planned outage days and the remaining hours will be counted towards the penalty
- The penalty is assessed on a daily basis so the hours will be converted back to days and rounded down to the nearest day

*IMM and MISO will continue to review Urgent, Emergency and Forced outages to determine if they were known or reasonably known at the time of the PRA and if they should be counted towards the 31-day outage rule

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Exhibit 120
2024 OMS-MISO Survey

2024 OMS-MISO Survey Results

Furthering our joint commitment to regional resource adequacy, OMS and MISO are pleased to announce the results of the 2024 OMS-MISO Survey

CORRECTIONS
Reposted 6/20/2024
Slide 11 PRM% Updated

June 20, 2024

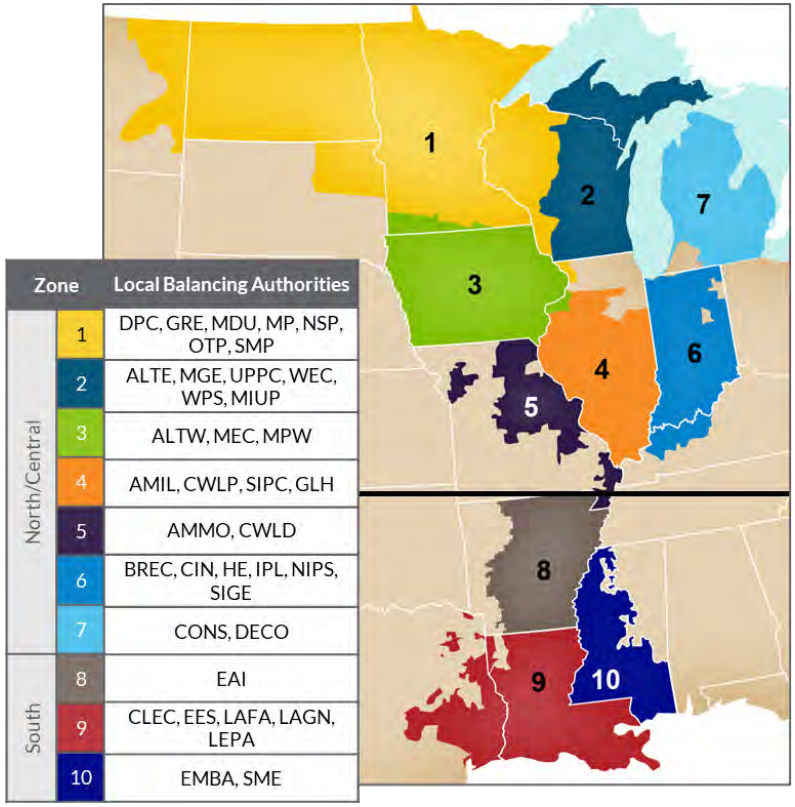
The 2024 OMS-MISO Survey reinforces near-term risks and highlights key uncertainties impacting resource adequacy in the MISO region

- Results indicate a potential surplus of 1.1 GW to a deficit of 2.7 GW for the summer of PY2025/26, depending on critical, yet uncertain, drivers such as the pace and quantity of new resource additions and projected resource retirements.
- Resource Adequacy risks could grow over time across all seasons, absent increased new capacity additions and actions to delay capacity retirements.
- Significant economic development activities are spurring new, large spot-load additions (e.g., data centers, onshoring of manufacturing, new industrials) and increasing pressures on resource adequacy and requiring improved abilities for the timely addition of new resources.
- Recent reforms to MISO's resource adequacy construct will enhance MISO's ability to accurately assess the changing resource adequacy risks driven by extreme weather, the rapid growth of weather-dependent resources, and the retirement of dispatchable resources.
- Results highlight resource adequacy challenges in the MISO region and the need for continued collaboration between OMS, MISO, and its Members to maintain a reliable electricity system.

All presentation references to capacity indicate Seasonal Accredited Capacity (SAC)

The OMS-MISO Survey provides a resource adequacy view over a five-year horizon based on currently available information

- The survey results indicate the degree to which expected capacity resources satisfy planning reserve margin requirements with either a surplus or a deficit.
- The survey considers that Load Serving Entities (LSEs) within each zone must have sufficient resources to meet load and required reserves.
- Surplus resources may be shared among LSEs with resource deficits to meet reserve requirements.



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

This year's survey includes an updated baseline methodology to reflect the changing pace of new resource additions. Various scenarios for projected capacity and anticipated large spot-load additions across the MISO region are also included to highlight the increasing uncertainty and evolving risk.

90% of existing generation capacity participated in OMS-MISO Survey in 2024.

Additional factors can impact projected deficits or surpluses that are observed in the survey

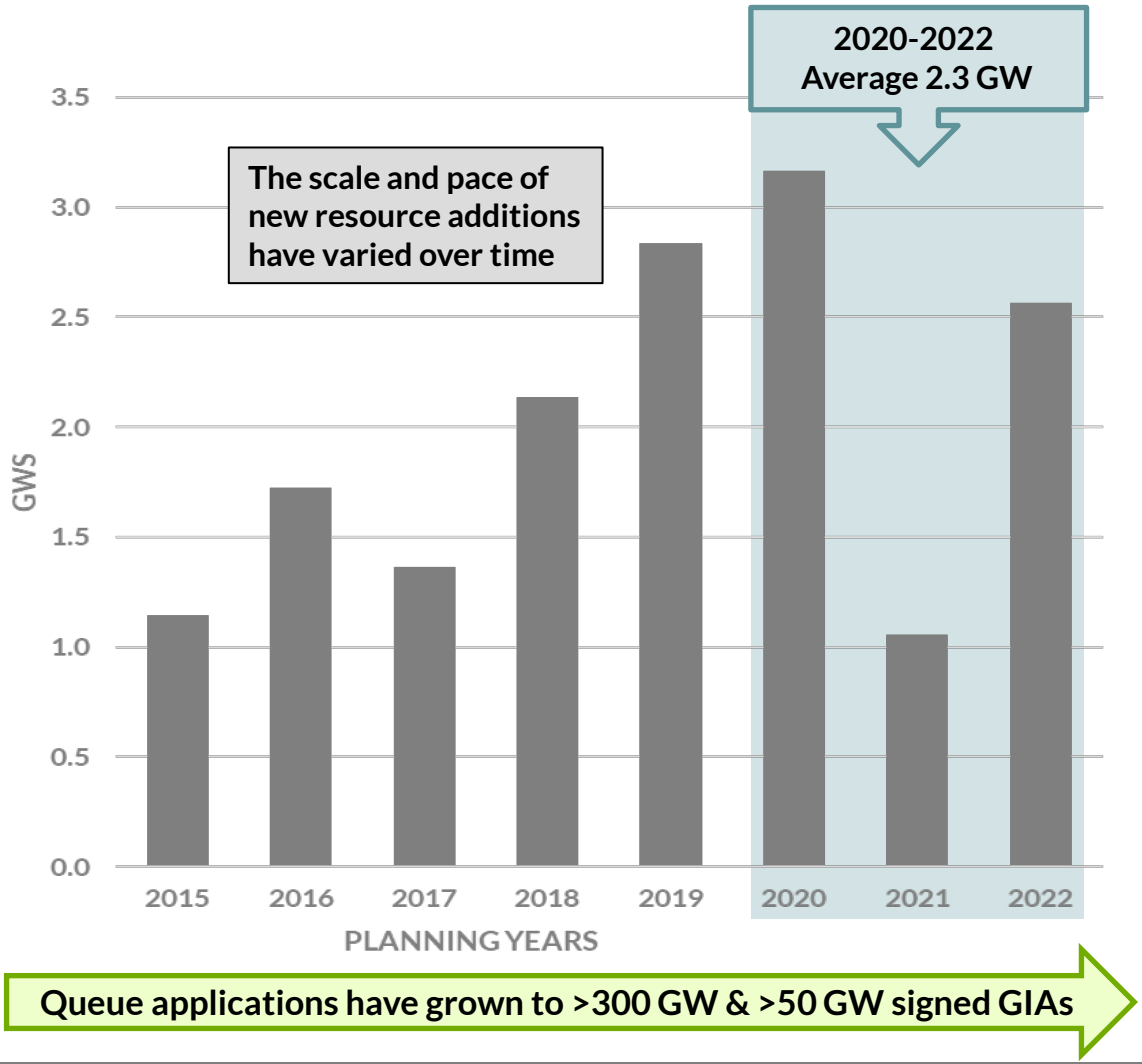
Downside Risks

- Continuing rapid pace of resource retirements
- EPA regulations further accelerating resource retirements
- Ongoing delays to capacity additions due to supply chain bottlenecks, permitting delays, and commercial challenges
- Continued queue challenges due to exceptionally large accumulated backlog and expectations for high quantities of future applications
- Higher load growth due to economic development and new, large spot-load additions (e.g., data centers and onshoring of manufacturing/new industrials), absent an improved ability to concurrently add new resources

Upside Possibilities

- Substantial new capacity enabled by the easing of supply chain bottlenecks, permitting constraints, and labor shortages
- Continued queue improvements to reduce speculative quantities and associated delays
- Market responses to local capacity deficits
- Improved price signals through market reforms, such as the Reliability Based Demand Curve, incentivizing additional capacity
- Improved ability to add new resources and support economic development and related new, large spot-load additions

Trends and market pressures related to new capacity additions suggest refinements are needed to better reflect uncertainty



In the past, it was reasonable to use probability-adjusted estimates applied to quantities of projects in various phases of queue development.

That's no longer applicable due to the larger queue and constraints faced by projects with signed generation interconnection agreements (GIAs). The 2024 survey uses a range of estimates for new resource additions:

1. **Three-Year Historical Average:** based on the historical rate of additions per planning year*
2. **Alternative Projection:** based on MISO's updated timing estimates from interconnection customers with GIAs*

Note: 2023 data unavailable during time of analysis. Including 2023 projects would change the 3-year average to 2.2 GW.
**Based on Historical averages defined on slide 6*

Understanding Resource Categories

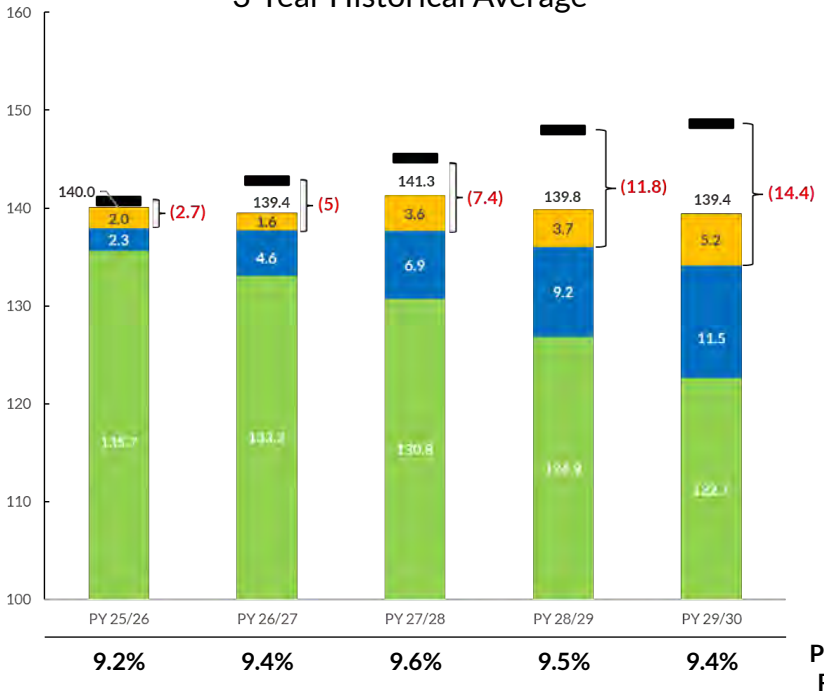
Resource Category	Past Practice	2024 Survey
Committed Capacity *Resources committed to serving MISO's load*	• Existing generation resources • Signed Generation Interconnection Agreement Projects • External resources with firm contracts to MISO load • Assumes resources will be used to meet PRMR	• **Same, except does not include signed Generation Interconnection Agreement (GIA) projects (Signed GIA projects moved to 'Potential New')**
Potential New Capacity	• Projects in the MISO Generator Interconnection Queue adjusted for queue phase and related probabilities for projects reaching commercial operations • Assumes resources will **NOT** be used to meet PRMR	• **Using 3-Year Historical Average: Capacity addition based (2.3 GW/year) based on the average new capacity built in Planning Years 2020-2022** • **Using Alternative Projection: Informed by timing estimates from interconnection customers with signed GIA projects* (6.1 GW/year)** • **Assumes resources <u>WILL</u> be used to meet PRMR**
Potentially Unavailable Resources *May be available to serve MISO's load but may not have firm commitments*	• Indicated as Low Certainty in survey results by Market Participants • Includes potential retirements or suspensions • Assumes resources will **NOT** be used to meet PRMR	• **No Changes**

***MISO Alternative Projection**: Responses indicate 6.8GW can be built for PY 2025/26. MISO data shows 90% of GIAs get built.*
PRMR: Planning Reserve Margin Requirement

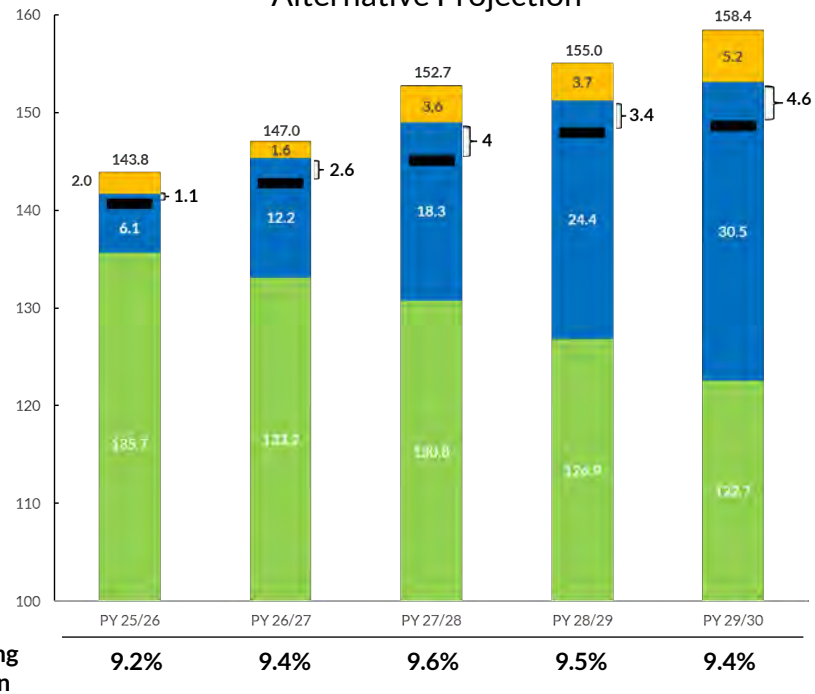
The 2024 OMS-MISO Survey illustrates a strong sensitivity to the pace of new capacity additions, with PY 2025/26 showing a range from a 2.7 GW deficit to a 1.1 GW surplus and widening thereafter

MISO Resource Adequacy Projection – Summer (GW)

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average*



Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



PRM% - Planning Reserve Margin	PY 25/26	PY 26/27	PY 27/28	PY 28/29	PY 29/30
	9.2%	9.4%	9.6%	9.5%	9.4%

Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Committed Capacity

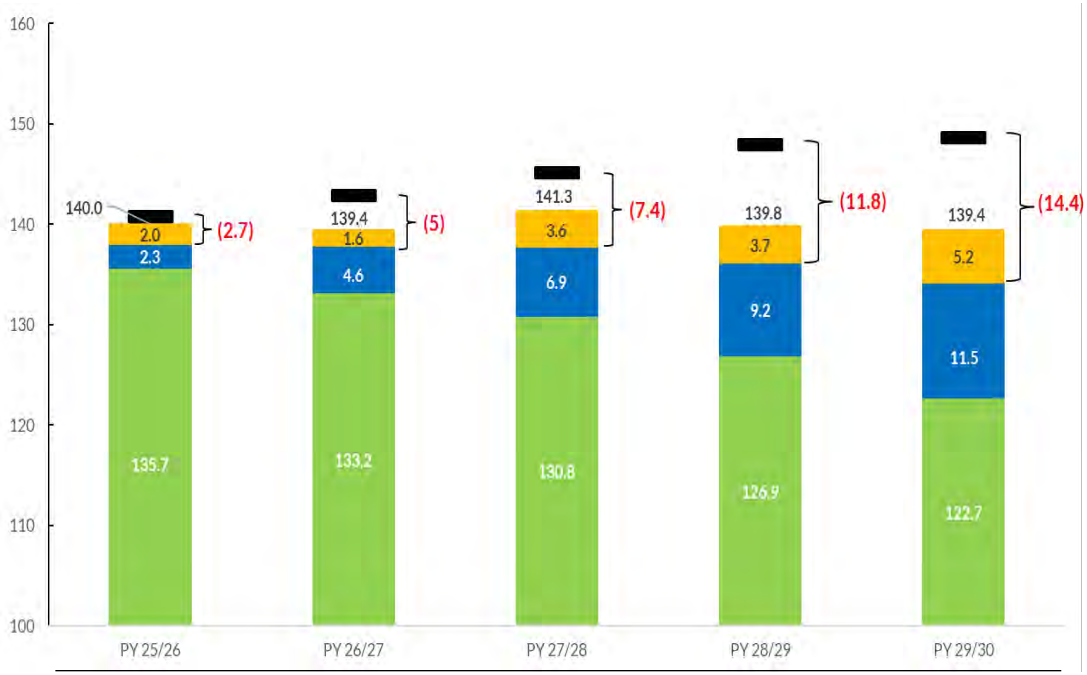
- Bracketed values indicate difference between Committed + Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
PRMR: Planning Reserve Margin Requirement
**Using methods for potential New Capacity described on Slide 6*

Continued pace of retirements and pressures on generation development could potentially result in deficits as early as PY 2025/26

MISO Resource Adequacy Projection – Summer (GW)

*Assuming **2.3 GW/yr** of Potential New Capacity added*
3-Year Historical Average*



PRM% - Planning Reserve Margin	9.2%	9.4%	9.6%	9.5%	9.4%

Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Committed Capacity

- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1,900 MW is reflected in this chart

Projection of 2.3 GW of new capacity per year derived from:

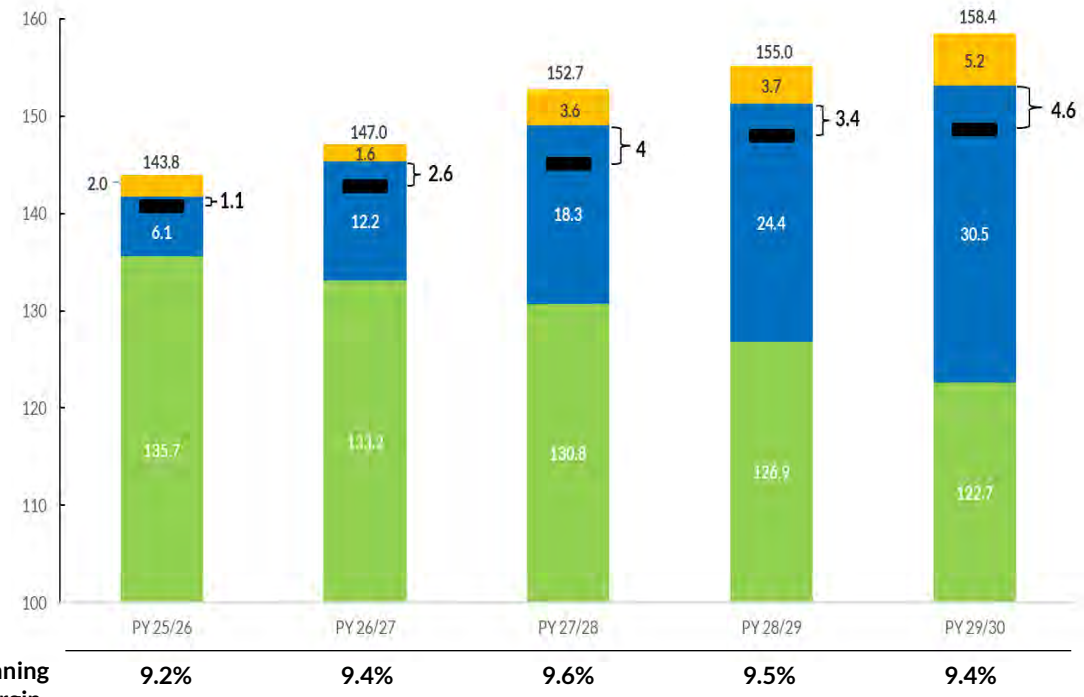
- Actual buildout over PYs 2020-2022
- Projected capacity buildout in line with historical rate
- Reflects impacts from COVID slowdown, such as continuing supply-chain bottlenecks, commercial uncertainty and permitting/labor delays

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
All references to capacity indicate Seasonal Accredited Capacity (SAC)
**Using Potential New Capacity as described on slide 6*

Favorable changes in development drivers could accelerate capacity additions necessary to cover projected growth

MISO Resource Adequacy Projection – Summer (GW)

*Assuming **6.1 GW/yr** of Potential New Capacity added*
Alternative Projection*



PRM% - Planning Reserve Margin	9.2%	9.4%	9.6%	9.5%	9.4%

Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Committed Capacity

- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1,900 MW is reflected in this chart

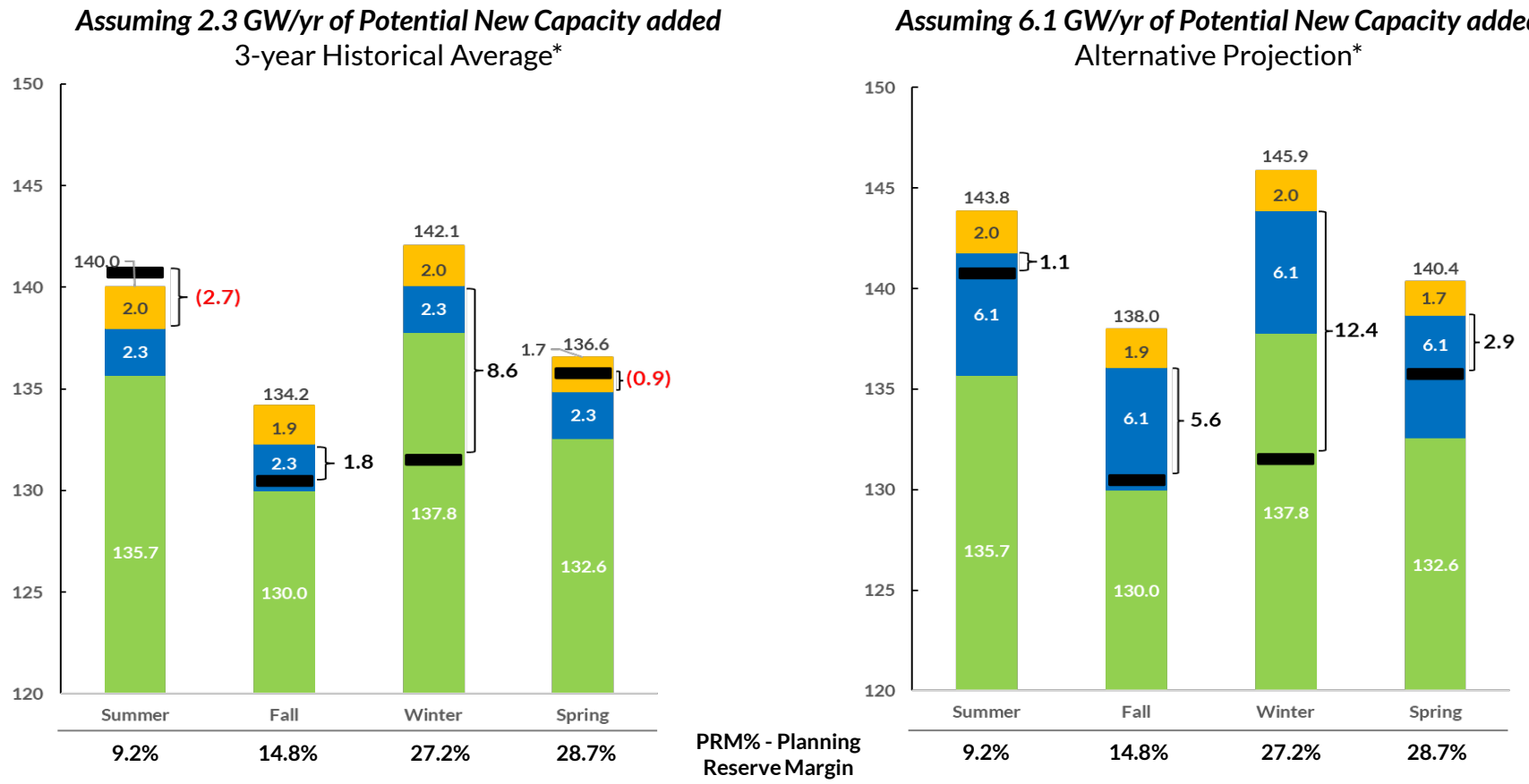
Projection of 6.1 GW of new capacity per year dependent upon:

- Easing of supply chain bottlenecks
- Reduced permitting-related delays
- Adequate supply of skilled labor
- Supportive commercial viability
- Continued queue improvements to reduce speculative quantities and associated delays

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
All references to capacity indicate Seasonal Accredited Capacity (SAC)
**Using Potential New Capacity as described on slide 6*

Seasonal comparison for PY 2025-26 shows the greatest risk in summer and spring

MISO Resource Adequacy Projection 2025/26 (GW)



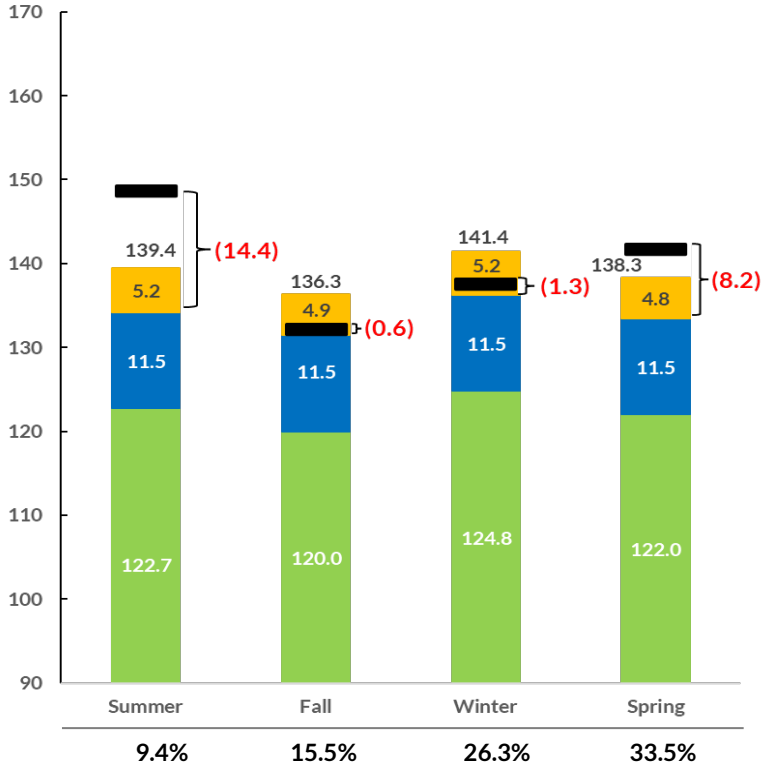
- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1,900 MW is reflected in this chart

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
PRMR: Planning Reserve Margin Requirement
**Using Potential New Capacity as described on slide 6*

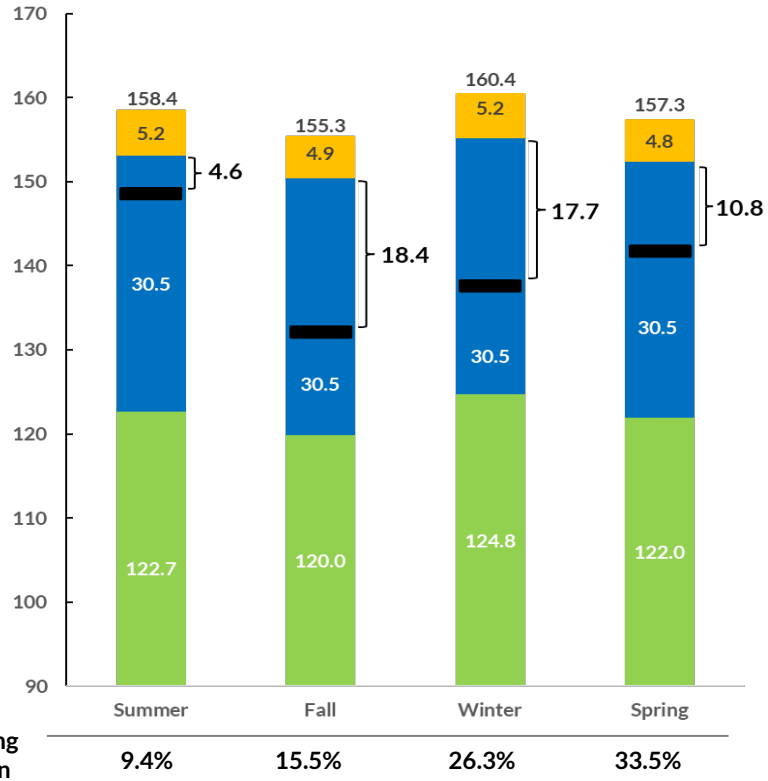
Projections for PY 2029/30 show increased reliance on new resources to meet PRMR

MISO Resource Adequacy Projection 2029/30 (GW)

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average*



Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



PRM% - Planning Reserve Margin

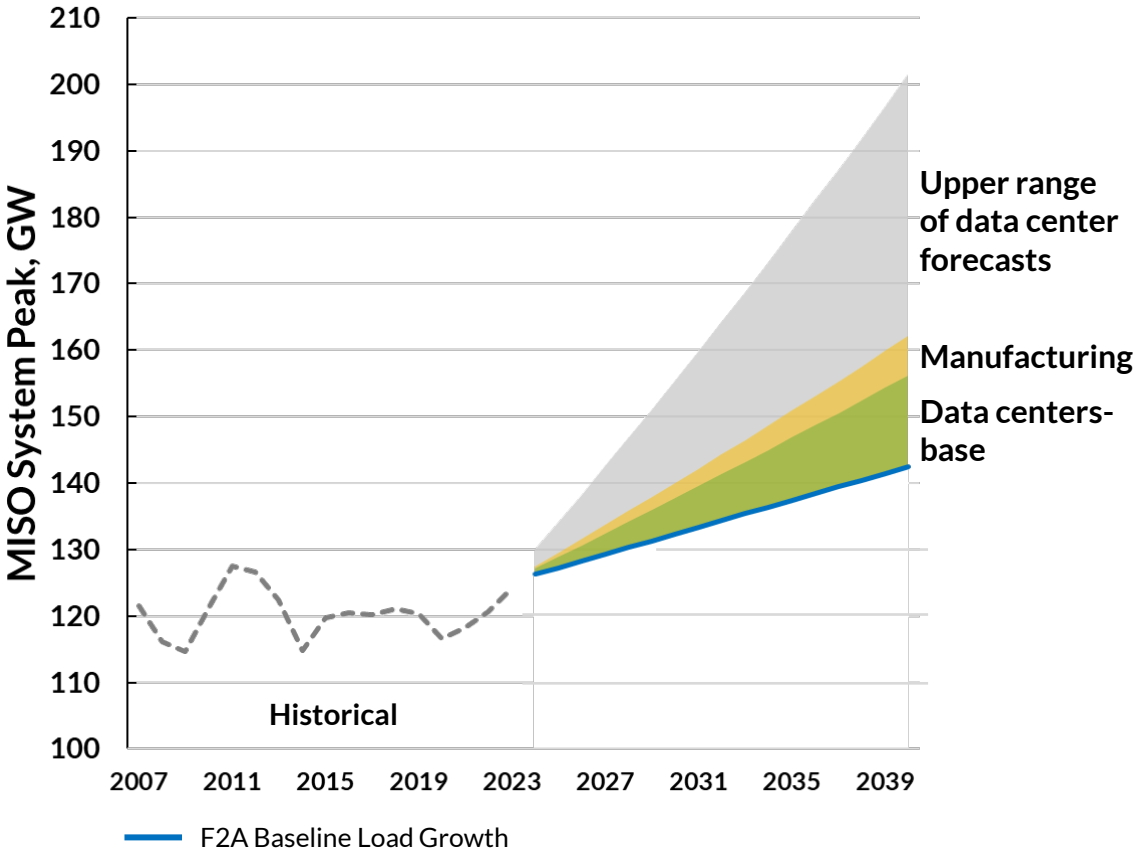
Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Committed Capacity

- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1,900 MW is reflected in this chart

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
PRMR: Planning Reserve Margin Requirement
**Using Potential New Capacity as described on slide 6*

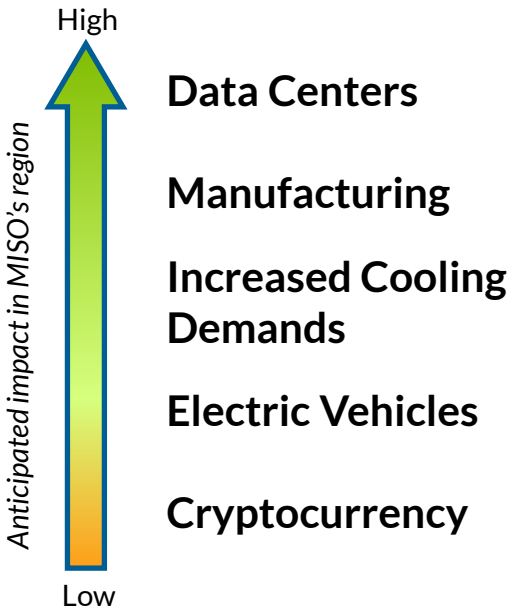
MISO's future long-term load forecasts will account for emerging digital demands, industrial expansion and climate changes

EPRI and Grid Strategies[1] anticipate manufacturing growth to favor MISO's service area



Note: *All figures shown are PRELIMINARY*

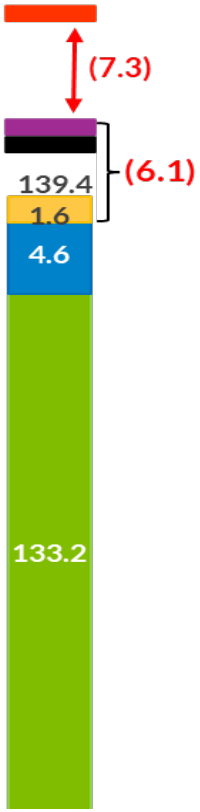
- Grid planners nearly *doubled* their 5-year peak load growth forecasts since last year
- MISO anticipates strong *long-term* load growth driven primarily by:



See appendix slide 31 with load forecast updates of other grid operators, potential new data centers in MISO and other commentary

1: https://www.epri.com/research/products/000000003002027930; https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

NEW: The 2024 OMS-MISO Survey includes sensitivities considering a range of new, large spot-load additions



Illustrative Example: PY 2026/27 Using Three-Year Historical Average

PRMR based on a higher range of large spot-load additions

- Uses MISO Future 2A as starting point[1]
- Models higher load-growth scenario using data from third-party consultants based on aggressive buildout of large load spot additions[2]

PRMR considering large spot-load additions

- Uses MISO Future 2A as starting point[1]
- Models increased demand based on public announcements for proposed data centers and manufacturing facilities within the MISO region[2]

PRMR based on LSE submitted load forecast

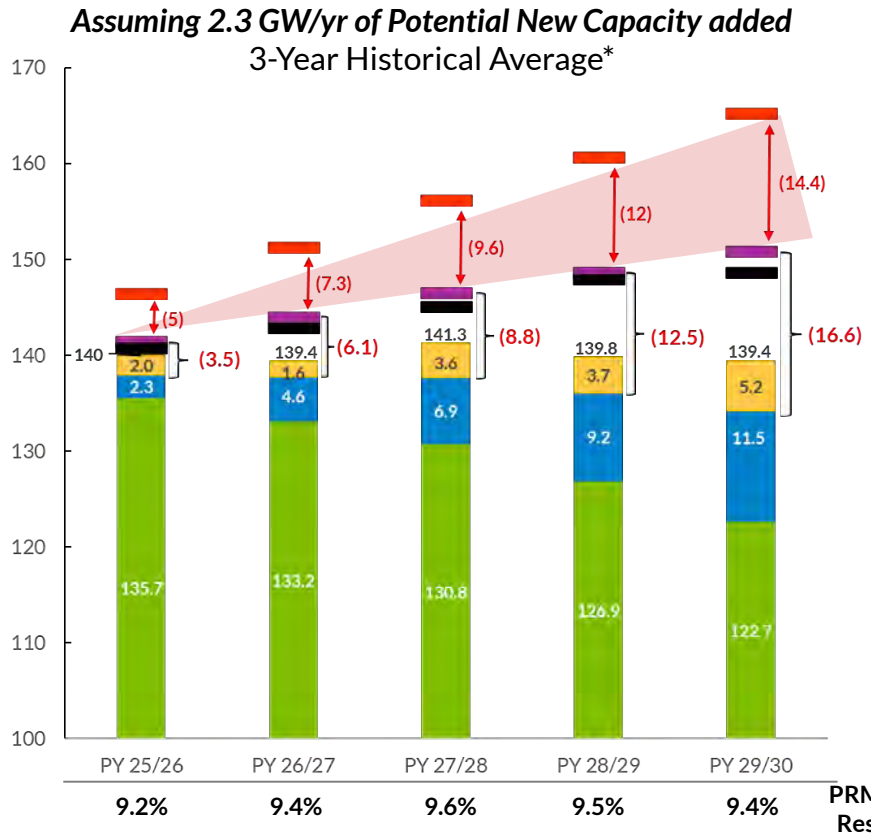
- LSE-submitted Non-Coincident Peak Forecast (NCPF) converted to Coincident Peak Forecast (CPF) using MISO posted Coincidence Factors
- Transmission losses added
- PRMR calculated using out year PRM% from PY 2024/25 LOLE Study

[1] https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf, [2] *See slides 12 & 31 for more information*

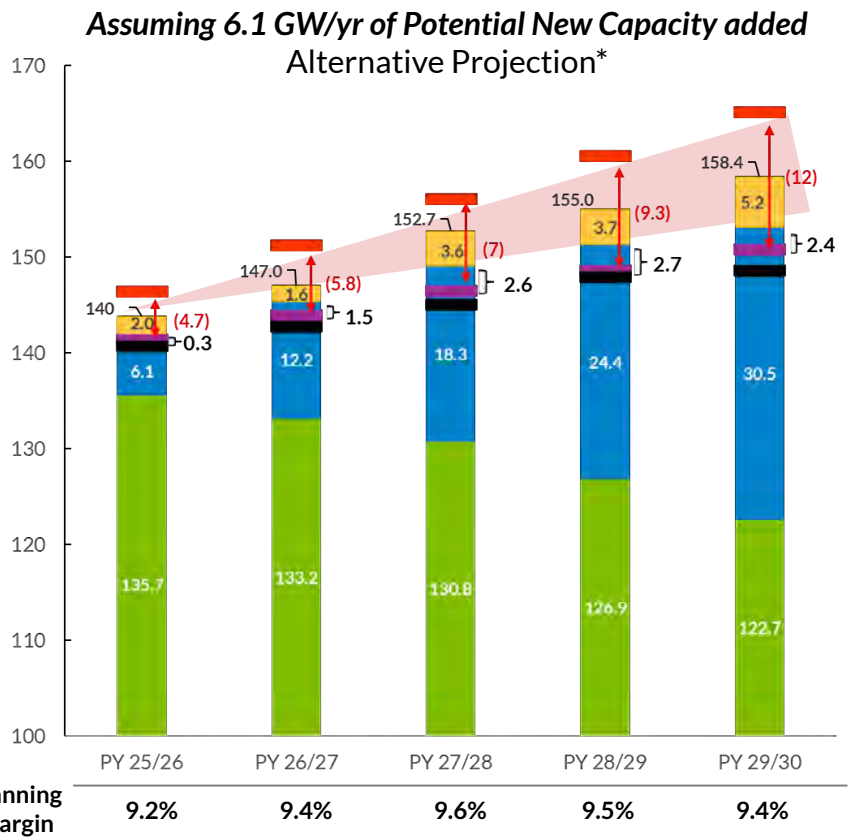
PRMR: Planning Reserve Margin Requirement LSE: Load Serving Entity LOLE: Loss of Load Expectation

Capacity deficits continue to grow in the near and long term under a large spot-load additions scenario

MISO Resource Adequacy Projection – Summer (GW)



PRM% - Planning Reserve Margin



- Projected PRMR for high range of Large Spot-Load Additions
- Projected PRMR with Large Load Spot Additions
- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Committed Capacity

- Bracketed values indicate difference between Committed + Projected New Capacity and Projected PRMR with large spot-load additions
- Red arrow values indicate the additional potential deficit with high-range large load growth case
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
PRMR: Planning Reserve Margin Requirement
**Using Potential New Capacity as described on slide 6*

MISO's existing accreditation methods can overstate a resource's capacity value during the highest risk periods, especially as the region's risk profile changes, leading to understated risk

- Increased reliance on wind, solar and storage, projected large-load additions and electrification, and frequent large-scale weather events are decoupling periods of risk from periods of high demand.
- These drivers are upending traditional methods for establishing reliability requirements and resource accreditation.
- MISO's proposed resource accreditation methodology* (Direct Loss of Load) will value a resource's marginal contribution to reliability during the highest risk periods.

MISO's proposed accreditation reforms, on file at FERC and targeted for implementation in PY 2028/29, will better measure a resource's contribution to reliability.

*See Resource Accreditation White Paper, published March 2024: https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1630728.pdf

The 2024 Survey shows that the near-term resource decisions made by utilities, regulators, MISO and its Members will determine whether the region's resources remain adequate

- Continued collaboration between OMS and MISO is necessary to maintain a reliable electricity system.
- The survey shows a range of potential resource adequacy outcomes, reinforcing near-term risks and illustrating key uncertainties impacting resource adequacy in the MISO region.
- Immediate actions are needed to expedite the addition of new capacity, coordinate resources for new load additions, and potentially moderate the pace of resource retirements.
- MISO's reforms under the Reliability Imperative are timely and responsive to the drivers contributing to resource adequacy challenges.
    - Implemented: Seasonal construct and thermal accreditation
    - Filed at FERC: 1) Reliability-Based Demand Curve, 2) resource accreditation
    - Ongoing reforms: 1) Load Modifying Resource accreditation, 2) Resource adequacy risk modeling improvements, 3) Attributes Roadmap, 4) LRTP, 5) JTIQ, 6) Queue Reforms

Appendix

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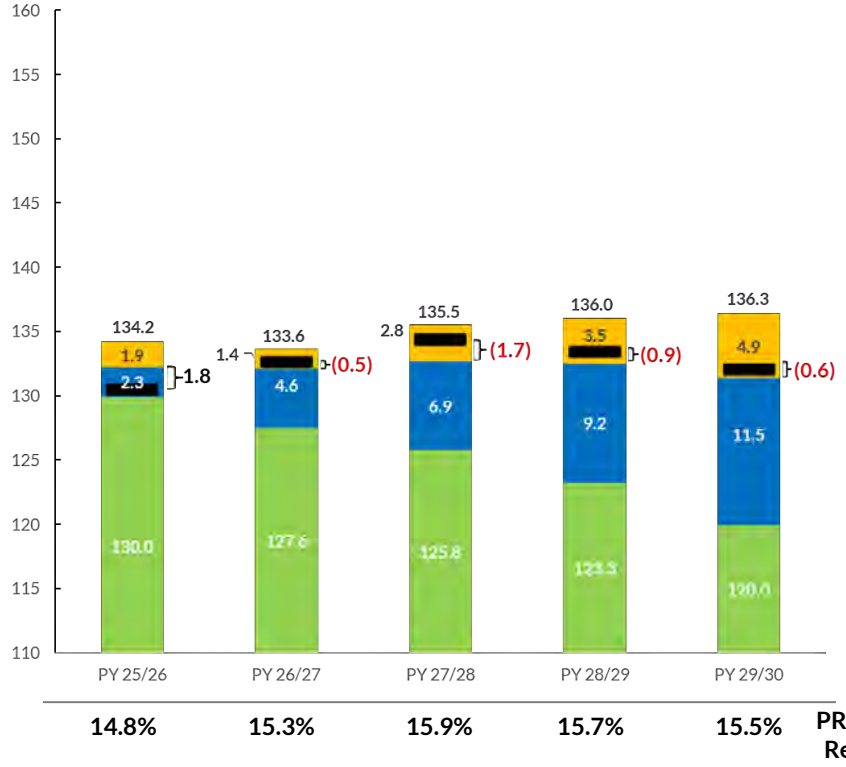
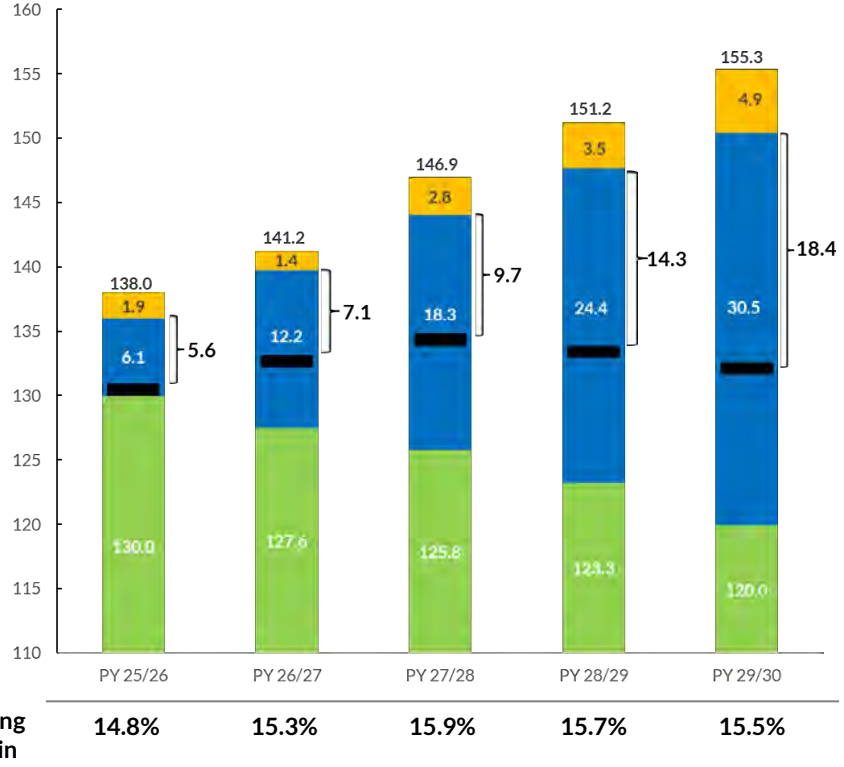
Fall capacity ranges from 1.8 GWs to 5.6 GWs surplus in the prompt year

MISO Resource Adequacy Projection – Fall (GW)

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average*



Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



PRM% - Planning Reserve Margin

Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Committed Capacity

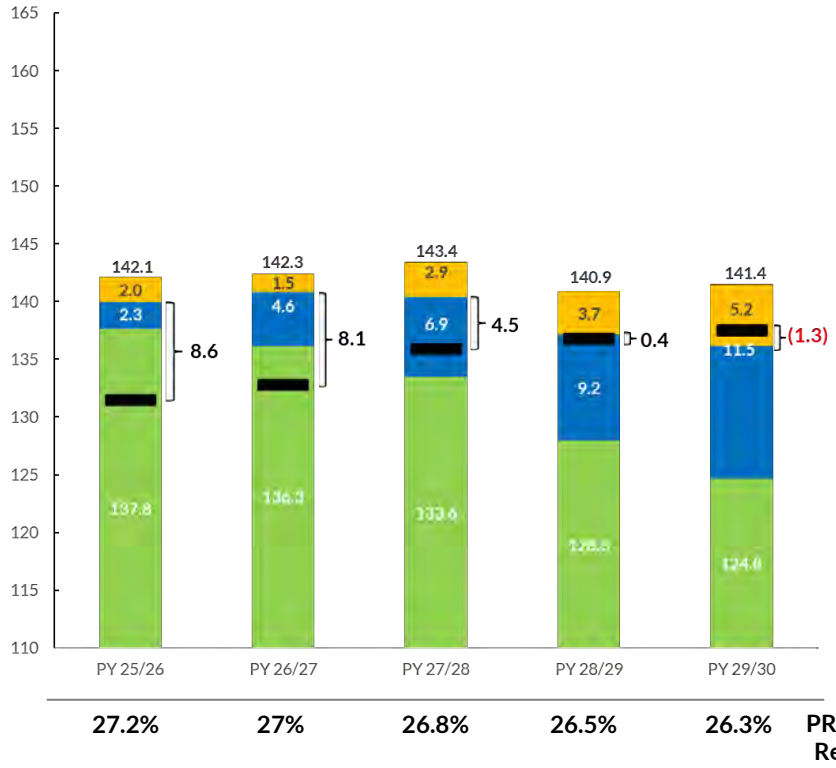
- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart
- Fall demand and PRMR calculated by using summer and winter demand forecast percent change seen year-over-year since out year Non- Coincident Peak Forecast (NCPF) is not submitted for out years for fall and spring

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
PRMR: Planning Reserve Margin Requirement
**Using Potential New Capacity as described on slide 6*

Winter capacity ranges from 8.6 GWs to 12.4 GWs surplus in the prompt year

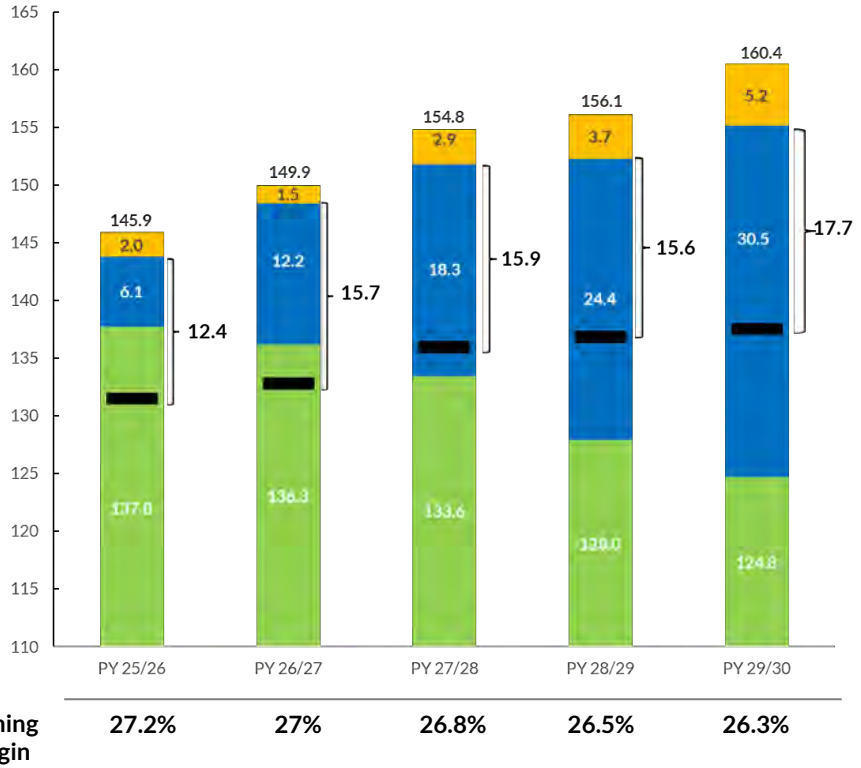
MISO Resource Adequacy Projection – Winter (GW)

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average *



PRM% - Planning Reserve Margin	PY 25/26	PY 26/27	PY 27/28	PY 28/29	PY 29/30
	27.2%	27%	26.8%	26.5%	26.3%

Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



PRM% - Planning Reserve Margin	PY 25/26	PY 26/27	PY 27/28	PY 28/29	PY 29/30
	27.2%	27%	26.8%	26.5%	26.3%

Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Committed Capacity

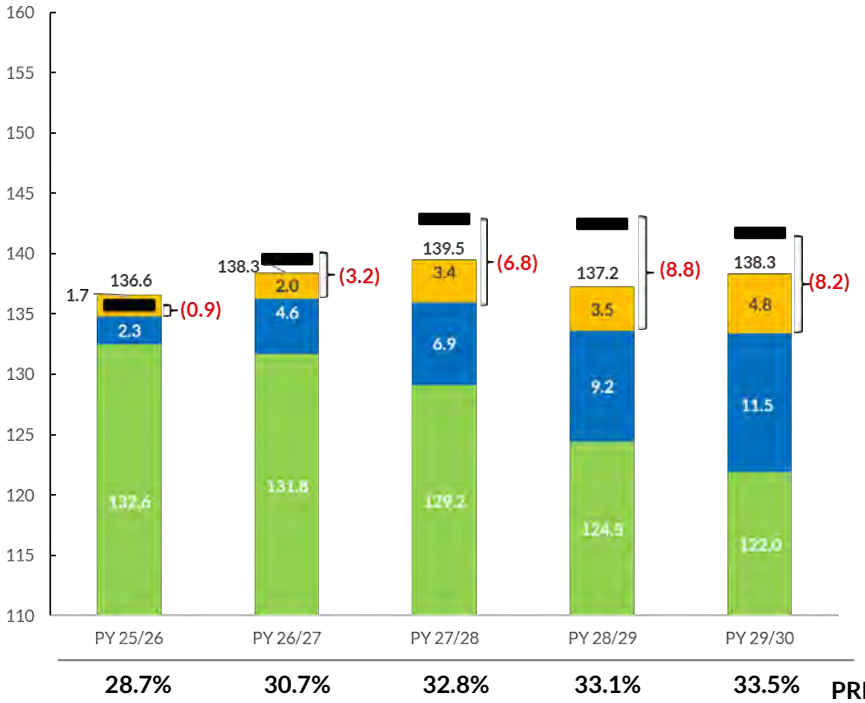
- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
PRMR: Planning Reserve Margin Requirement
**Using Potential New Capacity as described on slide 6*

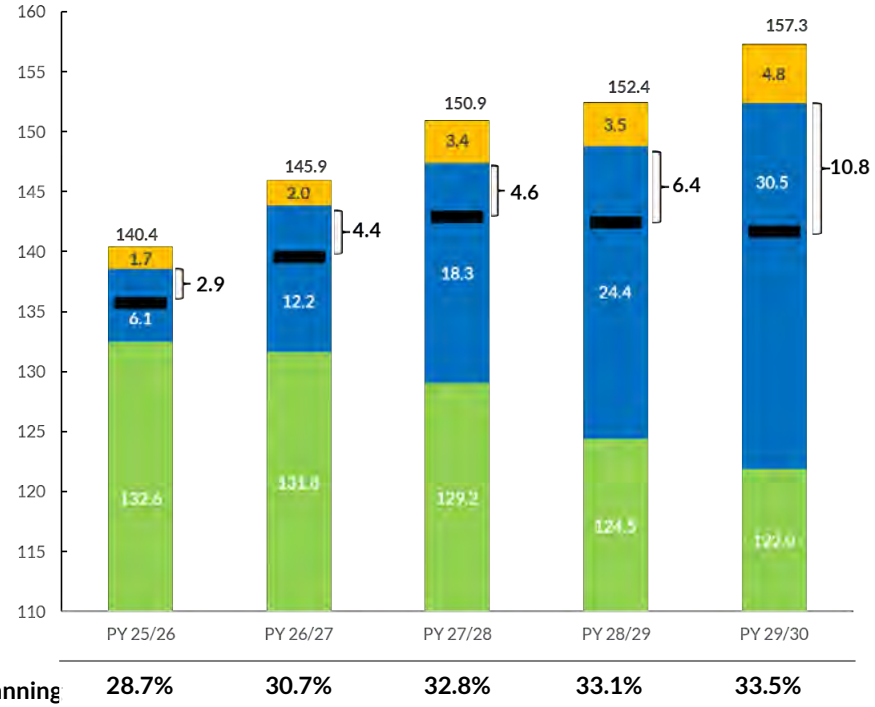
Spring capacity ranges from 0.9 GWs deficit to 2.9 GWS surplus in the prompt year

MISO Resource Adequacy Projection – Spring (GW)

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average *



Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



PRM% - Planning Reserve Margin

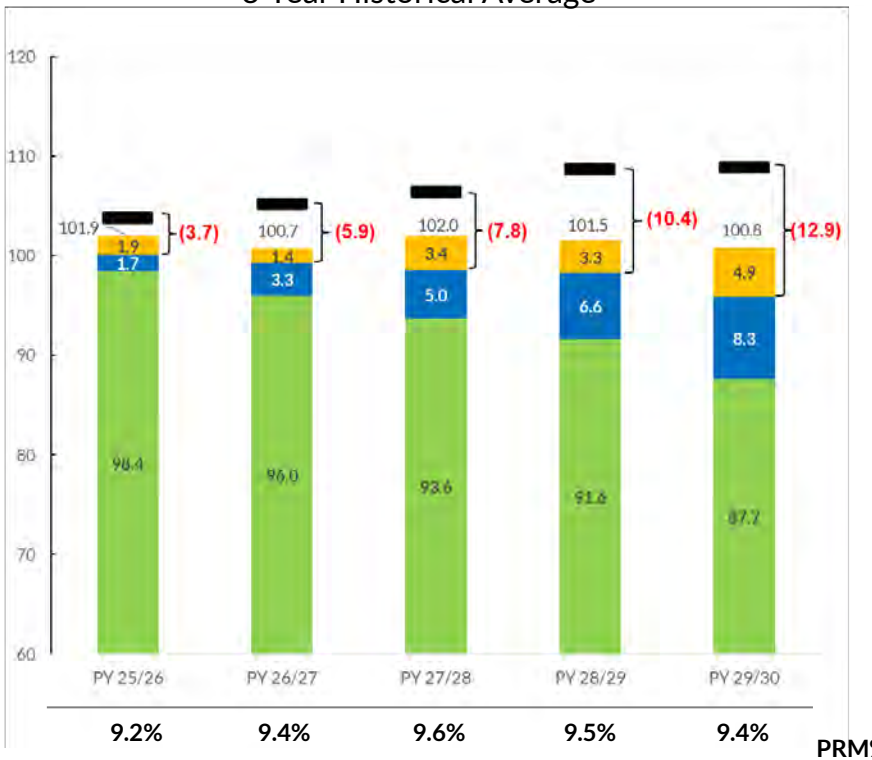
Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Committed Capacity

- Bracketed values indicate difference between Committed+ Projected New Capacity and Projected PRMR with LSE forecast
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart
- Spring demand and therefore PRMR is calculated by using Summer and Winter demand forecast percent change seen year over year since out year NCPF is not submitted for out years for Fall and Spring

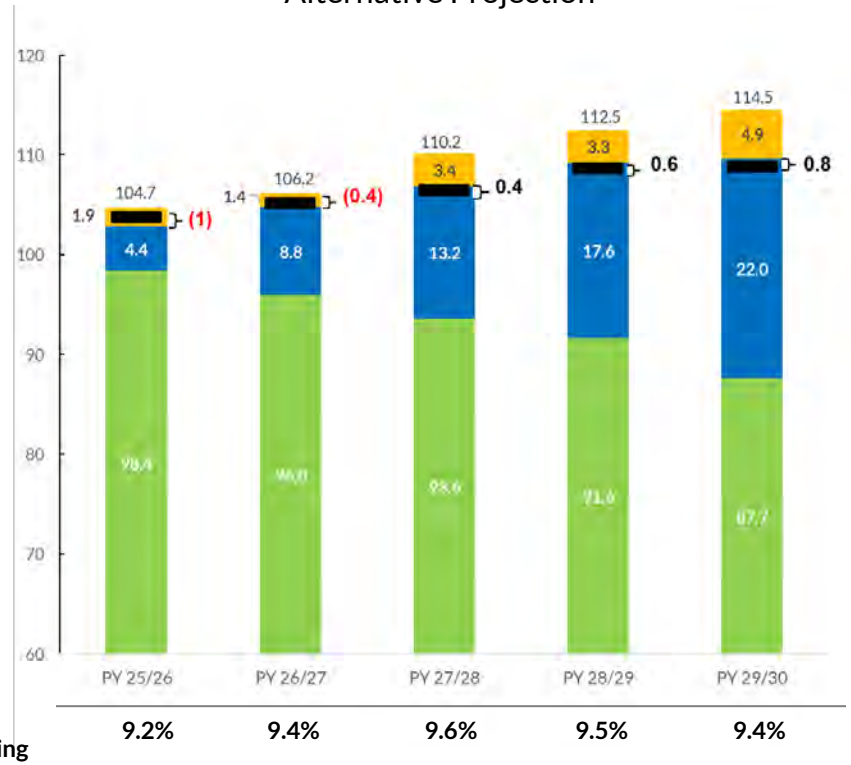
Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.
PRMR: Planning Reserve Margin Requirement
**Using Potential New Capacity as described on slide 6*

The North/Central subregion capacity for Summer ranges from 3.7 GWs to 1 GW deficit in the prompt year

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average *



Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



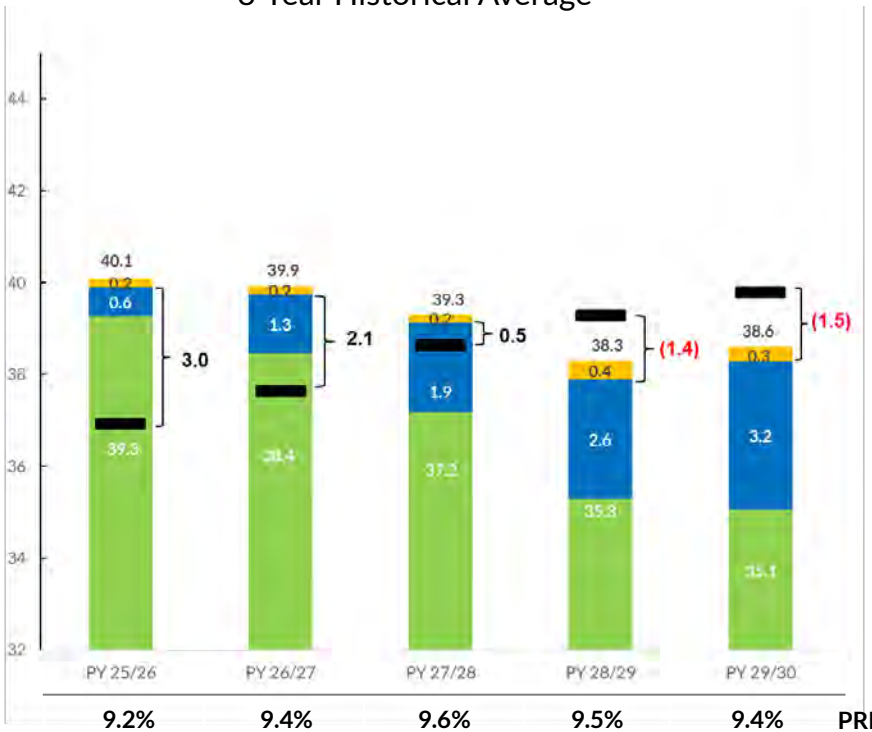
PRM% - Planning Reserve Margin

Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Committed Capacity

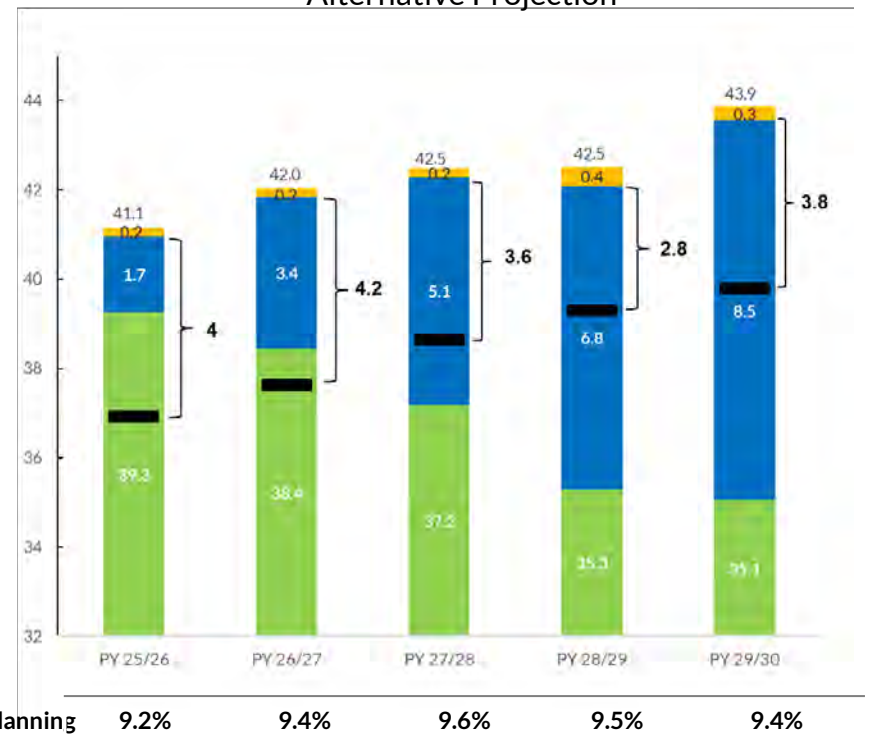
**Using Potential New Capacity as described on slide 6*
Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency. While RDT is not reflected in these charts the limit is currently modeled at 1900 MW in Resource Adequacy. PRMR: Planning Reserve Margin Requirement.

The South subregion capacity for Summer ranges from 3 GWs to 4 GWs of surplus in the prompt year

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average *



Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



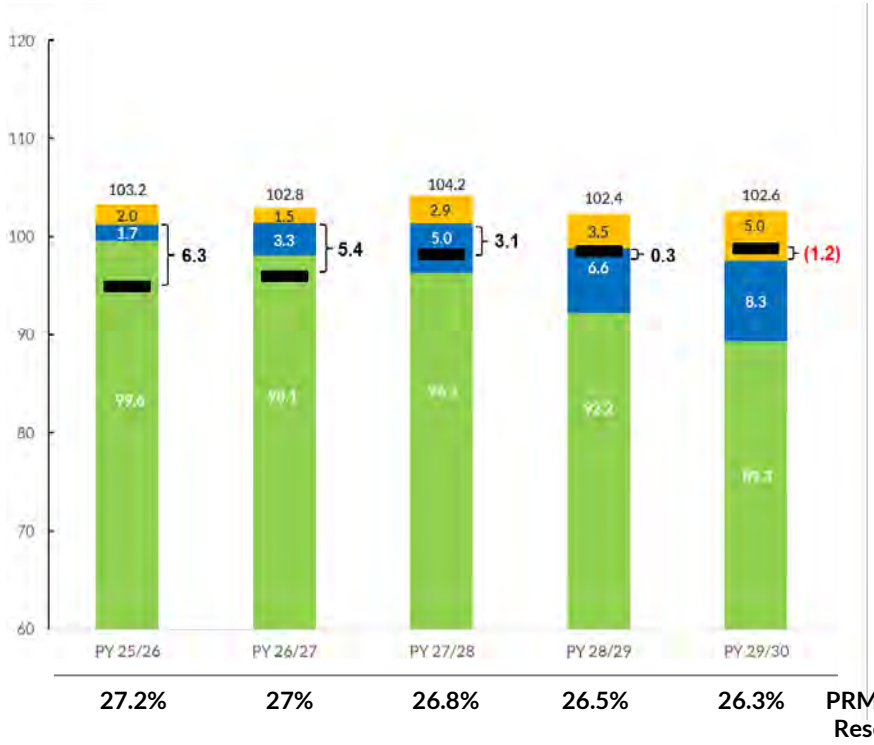
PRM% - Planning Reserve Margin	9.2%	9.4%	9.6%	9.5%	9.4%
	9.2%	9.4%	9.6%	9.5%	9.4%

Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Committed Capacity

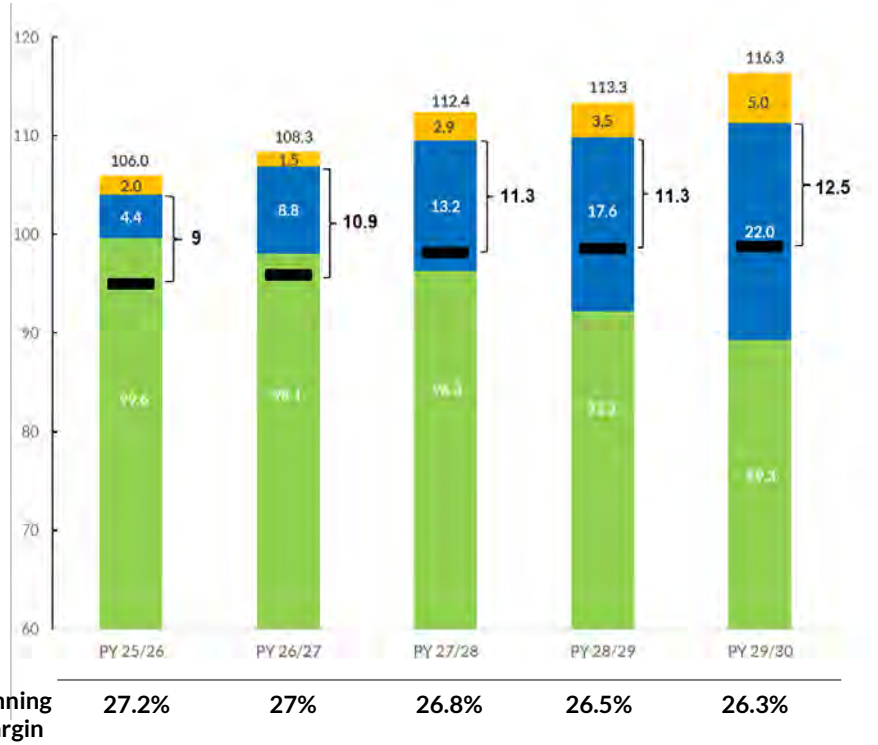
**Using Potential New Capacity as described on slide 6*
Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency. While RDT is not reflected in these charts the limit is currently modeled at 1900 MW in Resource Adequacy. PRMR: Planning Reserve Margin Requirement.

The North/Central subregion capacity for Winter ranges from 6.3 GWs to 9 GWs of surplus in the prompt year

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average *



Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



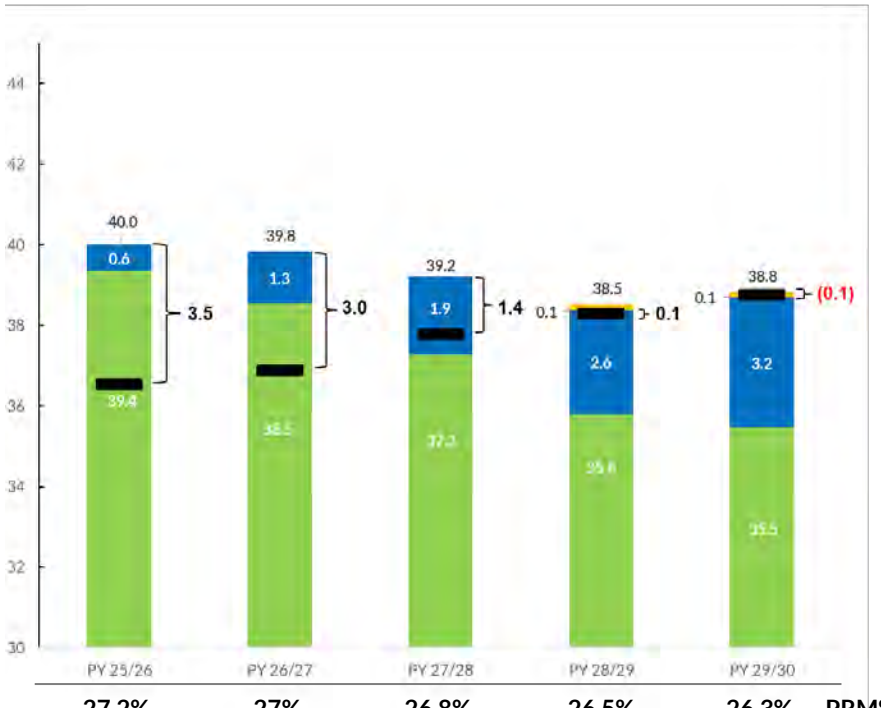
PRM% - Planning Reserve Margin					
27.2%	27%	26.8%	26.5%	26.3%	27.2%	27%	26.8%	26.5%	26.3%

Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Committed Capacity

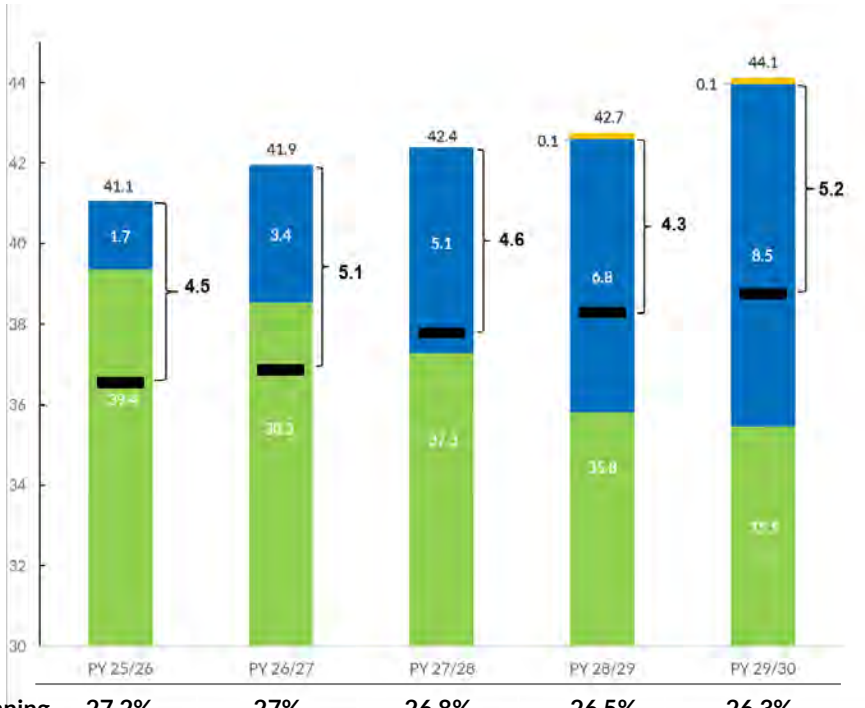
*Using Potential New Capacity as described on slide 6
Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency. While RDT is not reflected in these charts the limit is currently modeled at 1900 MW in Resource Adequacy. PRMR: Planning Reserve Margin Requirement.

The South subregion capacity for Winter ranges from 3.5 GWs to 4.5 GWs of surplus in the prompt year

Assuming 2.3 GW/yr of Potential New Capacity added
3-Year Historical Average *



Assuming 6.1 GW/yr of Potential New Capacity added
Alternative Projection*



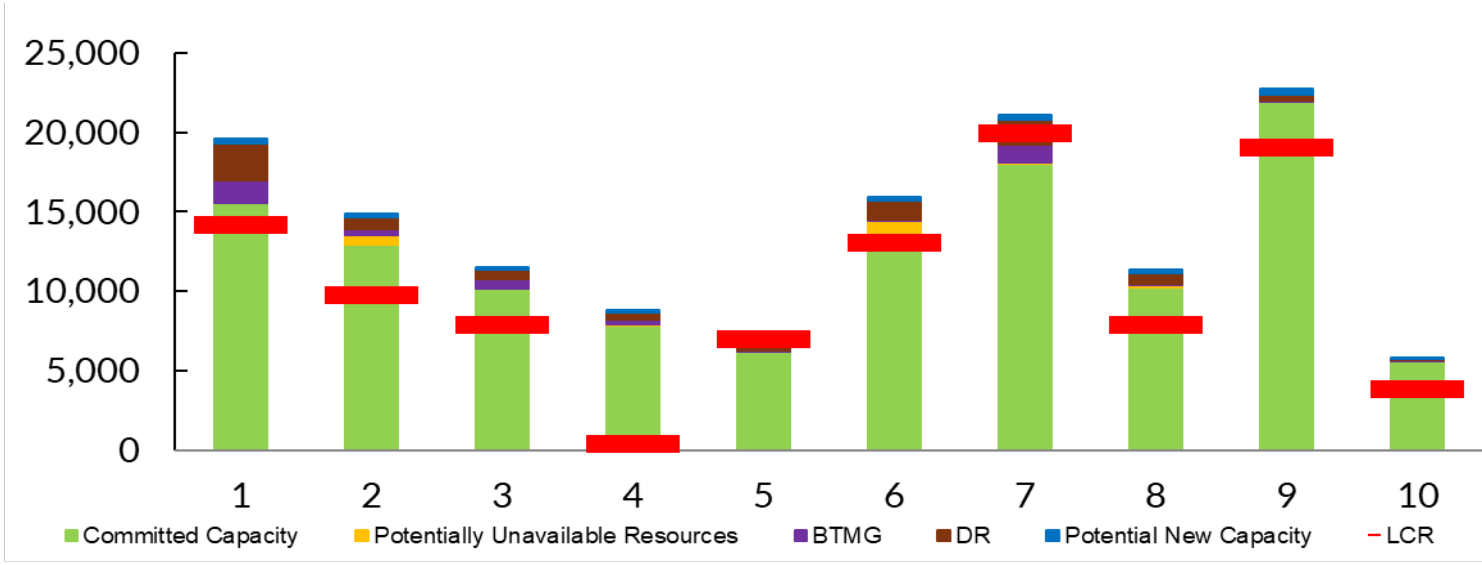
PRM% - Planning Reserve Margin	27.2%	27%	26.8%	26.5%	26.3%
	27.2%	27%	26.8%	26.5%	26.3%

Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Committed Capacity

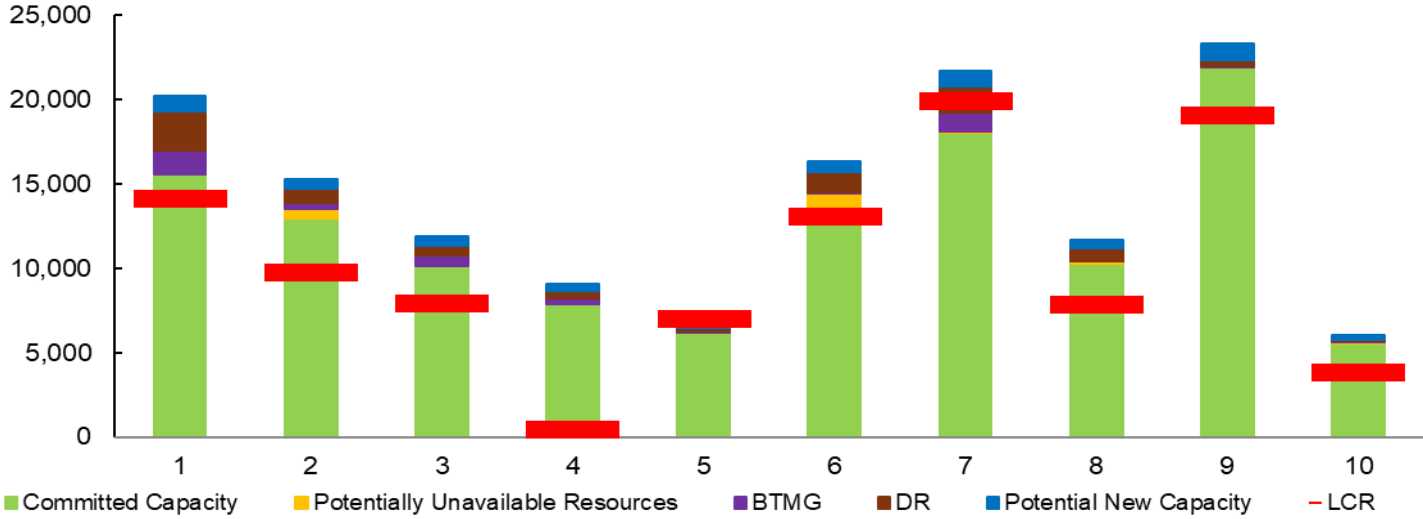
Using Potential New Capacity as described on slide 6
Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency. While RDT is not reflected in these charts the limit is currently modeled at 1900 MW in Resource Adequacy. PRMR: Planning Reserve Margin Requirement.

Summer PY 2025/26 Load Clearing Requirement (LCR) by zone

PY 2025/26 Summer by Zone vs. LCR (MW) Using 3-Year Historical average for new capacity*



PY 2025/26 Summer by Zone vs. LCR (MW) Using Alternative Projection for new capacity*

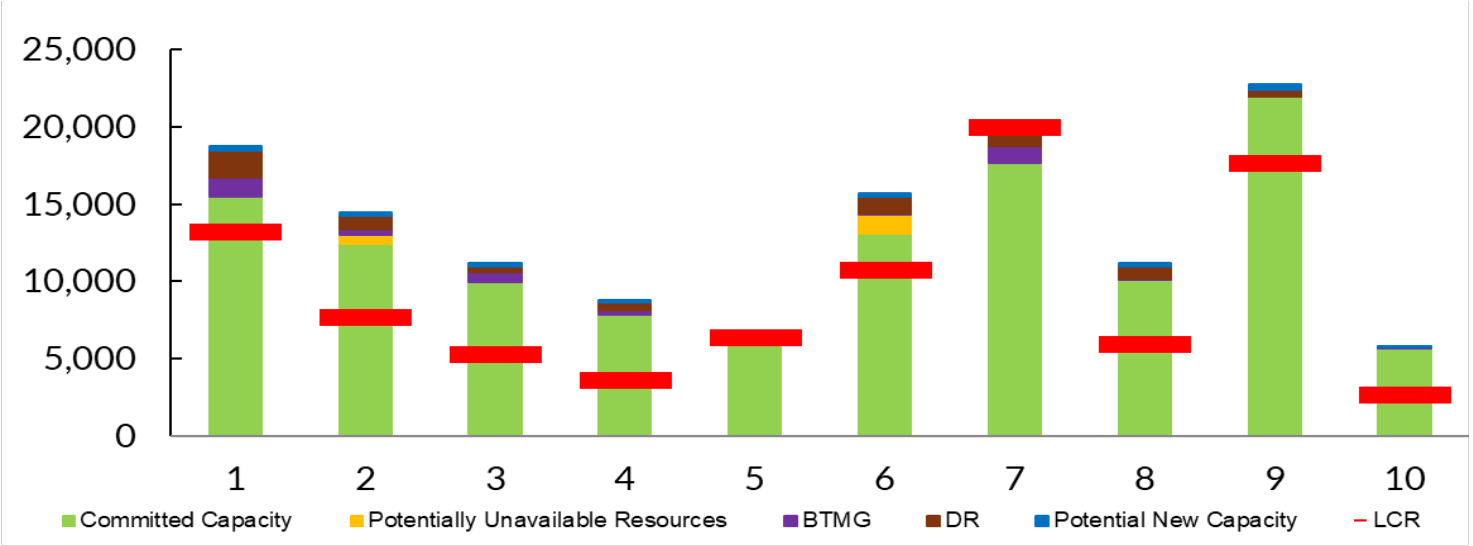


*Using Potential New Capacity as described on slide 6

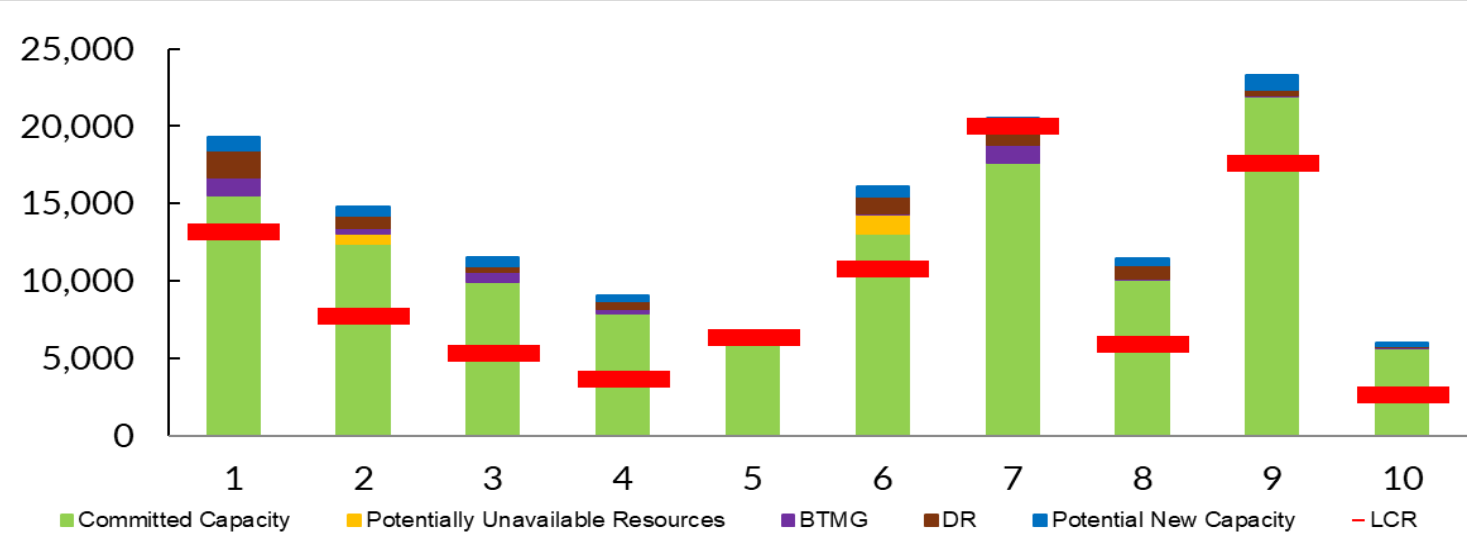
Includes only projected capacity resources within the zone (not imports and interzonal transfers). Potential Capacity for each zone is the average actual installed New Capacity used in the MISO overview slide proportional to that zones existing generation.

Fall PY 25/26 Load Clearing Requirement (LCR) by Zone

PY 2025/26 Summer by Zone vs. LCR (MW) Using 3-Year Historical average for new capacity*



PY 2025/26 Summer by Zone vs. LCR (MW) Using Alternative Projection for new capacity*

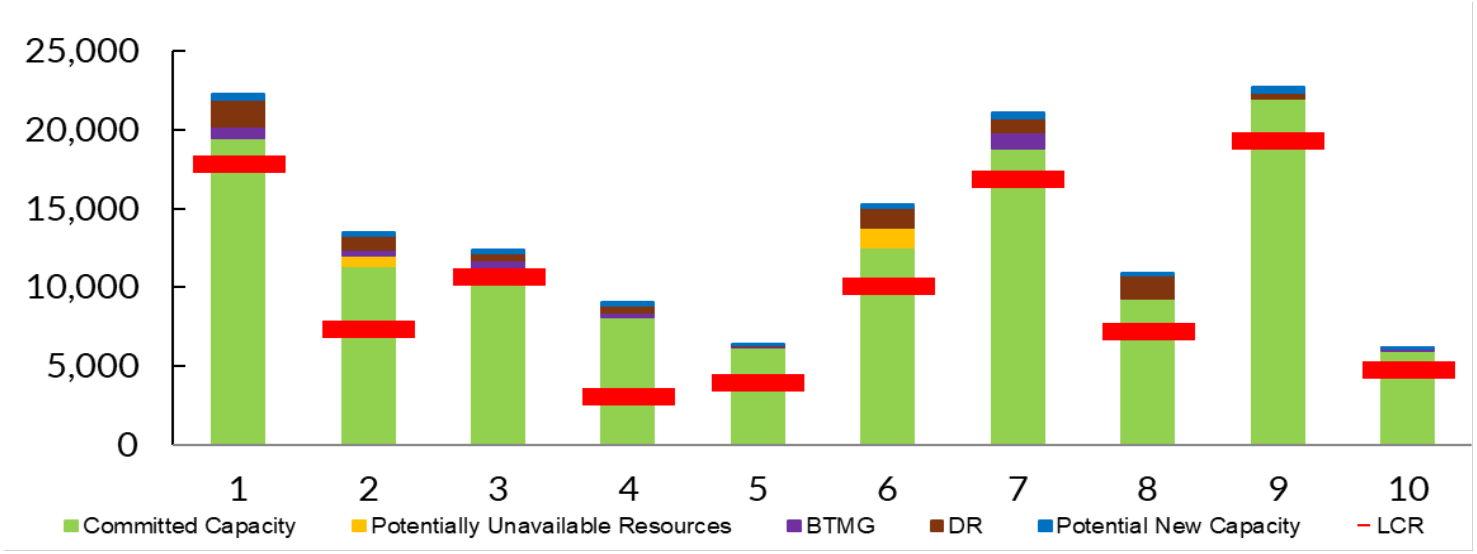


*Using Potential New Capacity as described on slide 6

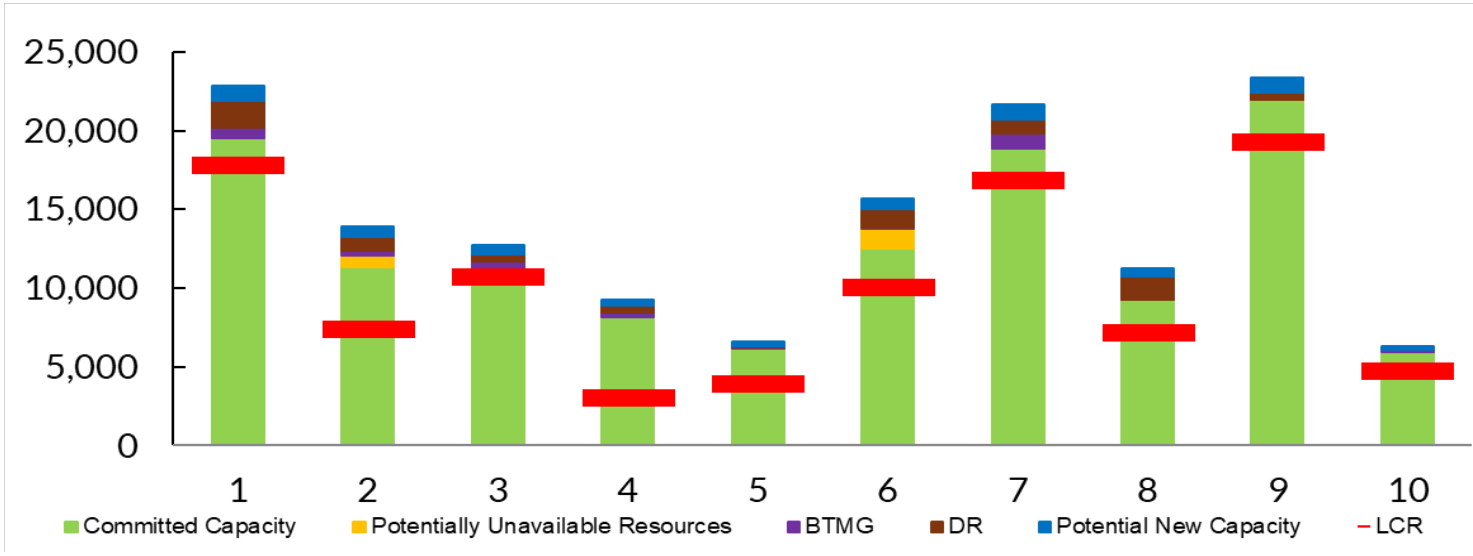
Includes only projected capacity resources within the zone (not imports and interzonal transfers). Potential Capacity for each zone is the average actual installed New Capacity used in the MISO overview slide proportional to that zones existing generation.

Winter PY 25/26 Load Clearing Requirement (LCR) by Zone

PY 2025/26 Summer by Zone vs. LCR (MW) Using 3-Year Historical average for new capacity*



PY 2025/26 Summer by Zone vs. LCR (MW) Using Alternative Projection for new capacity*

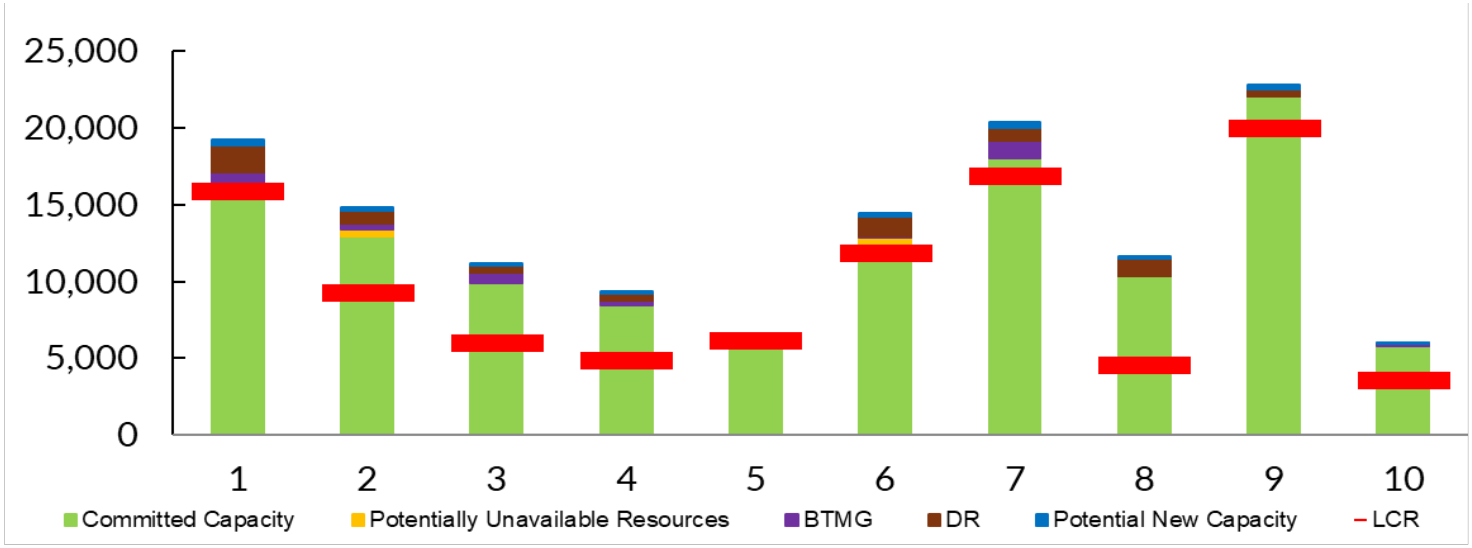


*Using Potential New Capacity as described on slide 6

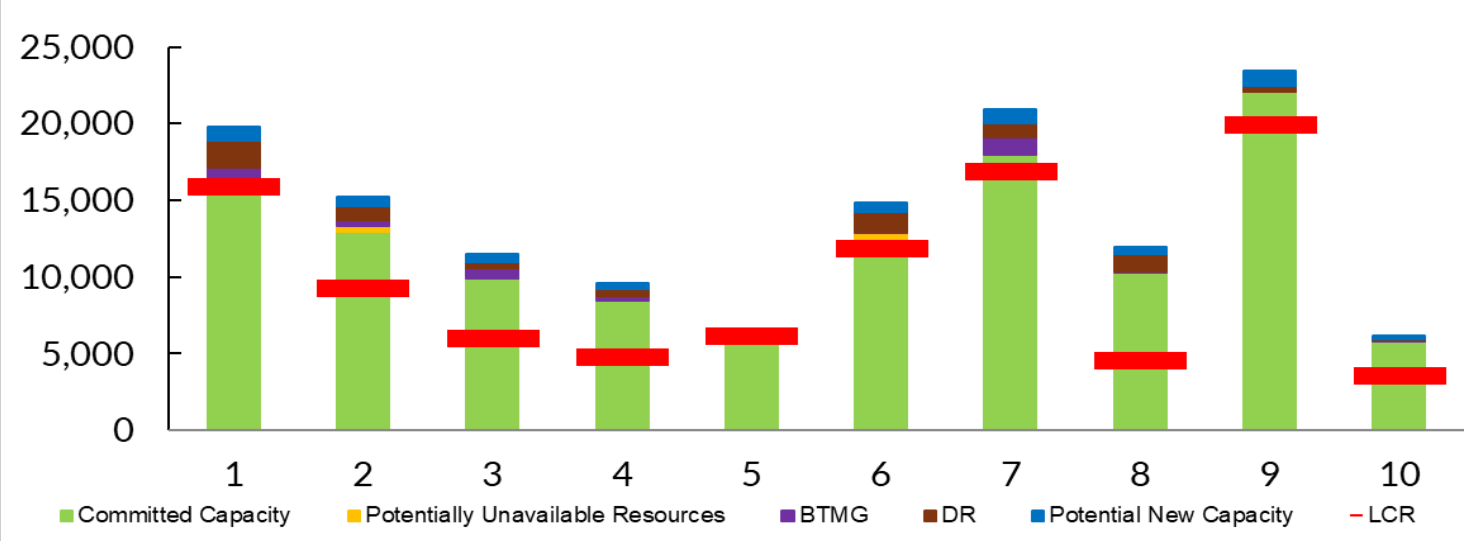
Includes only projected capacity resources within the zone (not imports and interzonal transfers). Potential Capacity for each zone is the average actual installed New Capacity used in the MISO overview slide proportional to that zones existing generation.

Spring PY 25/26 Load Clearing Requirement (LCR) by Zone

PY 2025/26 Summer by Zone vs. LCR (MW) Using 3-Year Historical average for new capacity*



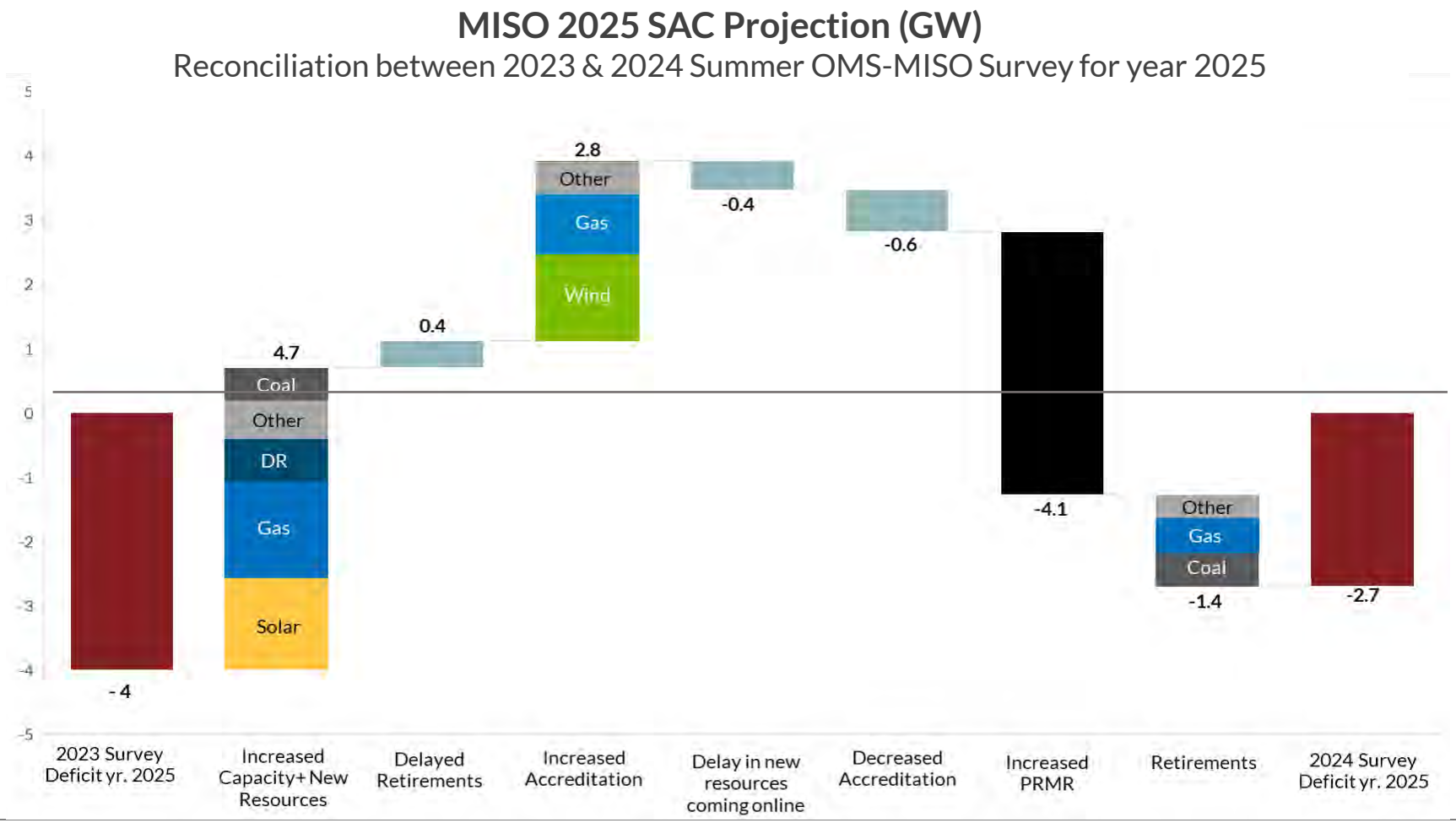
PY 2025/26 Summer by Zone vs. LCR (MW) Using Alternative Projection for new capacity*



*Using Potential New Capacity as described on slide 6

Includes only projected capacity resources within the zone (not imports and interzonal transfers). Potential Capacity for each zone is the average actual installed New Capacity used in the MISO overview slide proportional to that zones existing generation.

Year-over-year, the OMS-MISO Survey results show a decreased deficit due to increased response/new resources and increased accreditation, but a deficit remains largely driven by an increased Planning Reserve Margin Requirement



Higher load forecast included in 'Increased PRMR (Planning Reserve Margin Requirement)'
Other in 'Increased Response +New Resources': Wind, Battery, Hydro, and Oil
Other in 'Increased Accreditation' and Retirements: Other-Gas(CU ft), Water, Wood, Waste Heat