FILED
September 29, 2021
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a CENTERPOINT ENERGY INDIANA SOUTH ("CEI SOUTH") FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY PURSUANT TO IND. CODE CH. 8-1-8.5 FOR THE CONSTRUCTION OF TWO NATURAL GAS COMBUSTION TURBINES ("CTs") PROVIDING APPROXIMATELY 460 MW OF BASELOAD CAPACITY ("CT PROJECT"); (2) APPROVAL OF ASSOCIATED RATEMAKING AND ACCOUNTING TREATMENT FOR THE CT PROJECT; (3) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY PURSUANT TO IND. CODE CH. 8-1-8.4 FOR COMPLIANCE PROJECTS TO MEET FEDERALLY MANDATED REQUIREMENTS ("COMPLIANCE PROJECTS"); (4) AUTHORITY TO TIMELY RECOVER 80% OF THE FEDERALLY MANDATED COSTS OF THE COMPLIANCE PROJECTS THROUGH CEI SOUTH'S ENVIRONMENTAL COST ADJUSTMENT MECHANISM ("ECA"); (5) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE FEDERALLY MANDATED COSTS OF THE COMPLIANCE PROJECTS AND (B) POST-IN-SERVICE CARRYING CHARGES, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE CT PROJECT AND COMPLIANCE PROJECTS UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; (6) IN THE EVENT THE CPCN IS NOT GRANTED OR THE CTs OTHERWISE ARE NOT PLACED IN SERVICE, AUTHORITY TO DEFER, AS A REGULATORY ASSET, COSTS INCURRED IN PLANNING PETITIONER'S 2019/2020 IRP AND PRESENTING THIS CASE FOR CONSIDERATION FOR FUTURE RECOVERY THROUGH RETAIL ELECTRIC RATES; (7) ONGOING REVIEW OF THE CT PROJECT; AND (8) AUTHORITY TO ESTABLISH DEPRECIATION RATES FOR THE CT PROJECT AND COMPLIANCE PROJECTS ALL UNDER IND. CODE §§ 8-1-2-6.7, 8-1-2-23, 8-1-8.4-1 *ET SEQ.*, AND 8-1-8.5-1 *ET SEQ.*	)	**CAUSE NO. 45564**

PETITIONER'S SUBMISSION OF CORRECTIONS

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("Petitioner" or "CEI South"), by counsel, respectfully submits corrections to its case-in-chief in this Cause as identified in the table below. Items (1) through (5) and Item (12) have no quantitative effect at all, while Items (6) through (11) have an immaterial effect on Petitioner's requested relief in this Cause. More specifically, the corrections in Items (6) and (7) were made for clarity and are immaterial. Corrections in Item (9) were immaterial. With respect to Items (9) and (10), during the discovery process, an error was identified in the calculation that was used in Petitioner's 2019/2020 Integrated Resource Plan ("IRP") for the gas conversion options which overstated the fixed costs of gas conversion. Overall the net present value ("NPV") of the gas conversion options was overstated by approximately $50M (1.7% on the NPV in the reference case). Since this is fixed cost, it does not affect dispatch modeling. With respect to Item (11) corrections were immaterial.

Item	**Document**	**Page Reference (in clean copy)**	**Notes**
(1)	Pet. Ex. 2 (Games)	p. 17, line 6	Typographical error in date
(2)	Pet. Ex. 2 (Games)	p. 18, line 10	Erroneous table reference
(3)	Pet. Ex. 2 (Games)	p. 33, line 11	Erroneous witness name reference
(4)	Pet. Ex. 2 (Games)	p. 54, line 32	Typographical error in date
(5)	Pet. Ex. 5 (Rice)	Cover page p. 5, line 5 p. 7, lines 3 & 15-16 p. 8, line 20 p. 15, line 8 p. 19, line 8 p. 23, line 27 p. 24, line 2, 26, 37, and 38 p. 27, line 23	Typographical errors, including page number references to 2019-2020 IRP and Attachment name

		p. 37, line 18 p. 38, line 18 p. 41, line 16 & 31	
(6)	Pet. Ex. 5 (Rice)	p. 42, lines 8-9 and Table 6 p. 43, Tables 7&8 p. 44, Table 9 & lines 12-13 Attachment MAR-3 (Public), line 2 (Cost), line 7 (Savings),line 8 (Cost), line 9 (Total), lines 10-15 (Monthly Bill Impact 4CP) Attachment MAR-4 (Public), line 2 (Cost), line 9 (Savings), line 10 (Cost), line 11 (Total), Lines 12-17 (Monthly Bill Impact 4CP) Attachment MAR-5 (Public), lines 1-7, columns H, M, N & P, lines 17-18 & 20, column A Attachment MAR-6 (Public), lines 1-6, columns H, M, N, O & P, lines 17, 22 and 24, column A Attachment MAR-11 (Public), lines 10 & 13-16 Workpaper MAR-1 (Confidential) Generation Transition Workpaper	Corrections to remove securitization related to Culley 2 and include tax impact of replacing ABB1 and ABB2 with two CTs
(7)	Pet. Ex. 5 (Rice)	p. 21, Table 4 Updated to reflect values in Workpapers MAR-5 through -14	Slight corrections of NPVRR and 95th Percentile NPVRR (immaterial effect) and update inverted values for the ABB1 conversion portfolio around capacity purchases and sales.
(8)	Pet. Ex. 5 (Rice)	Workpaper MAR-15 (Public)	The ResourceEmissionsSQL tab was updated to include the two CTs (immaterial impact)
(9)	Pet. Ex. 5 (Rice)	p. 21, Table 4 and new footnote p. 33, lines 31-32 pp. 37-38, Table 5 and new footnote (p. 37) Workpaper MAR-5 (Public) Workpaper MAR-6 (Public) Workpaper MAR-7 (Public) Workpaper MAR-15 (Public)	Corrections and addition of explanatory footnote related to error identified in the fixed costs used in the calculation used in the IRP for gas conversion options.

(10)	Pet. Ex. 6 (Bacalao)	p. 6, line 7, Table 1 (Bridge ABB1 + ABB2) and new footnote p. 10, line 12, Table 2 and new footnote p. 11, line 13 p. 16, lines 5-6 & 11, Table 3, and new footnote Workpaper NB-1 Workpaper NB-2	Corrections related to error identified in the fixed costs used in the calculation used in the IRP for gas conversion options. Note: In Table 2, some items changed only in rank position, but the results of the analysis remain the same.
(11)	Pet. Ex. 6 (Bacalao)	p. 16, Table 3	Updated draft NPVRRs utilized within the analysis to match final IRP results in Workpaper MAR-15 (immaterial impact).
(12)	Pet. Ex. 8 (Grizzle)	p. 4, line 19	Correction to refer to informal RFP process

Redline (where practicable) and clean copies of the revised pages, attachments or workpapers are attached hereto or filed in Excel contemporaneously herewith. Updated Workpapers MAR-5, MAR-6 and MAR-7 will be provided on CD due to file size. Note that full copies of Mr. Rice's and Mr. Bacalao's updated testimony are being filed to accommodate new page breaks and footnote numbering. Where corrections affect a confidential page or workpaper, redacted public copies are filed herewith and the corrected confidential files are being uploaded via the Confidential tab of the Electronic Filing System in accordance with the Commission's Docket Entry dated July 1, 2021. Petitioner will include clean copies in the court reporter copies offered into evidence at the hearing. In addition, Petitioner is submitting herewith the verification page of Matthew A. Rice, which was inadvertently omitted previously.

Respectfully submitted,

Hillary J. Close

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served via electronic mail transmission this 29th day of September, 2021 to:

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DMS 21039819v1

Along with the condition of the scrubbers, another big challenge is the impact the original scrubbers have on the plant's operation and maintenance expense. The cost for chemical agents consumed to operate one of the A.B. Brown scrubbers is approximately [redacted] that of the forced oxidation scrubber used for F.B. Culley Unit 3. These chemical agents are trucked long distances creating delivery challenges. For example, during the 2021~~0~~ Polar Vortex event, Petitioner experienced challenges related to the delivery vendor keeping trucks moving to deliver and maintain adequate inventory of the chemicals for Petitioner to remain in compliance. Next, the chemical solution required to remove SO_2 is stored in an approximate one-million-gallon tank that sits in the open environment, making it difficult to maintain adequate chemistry for efficient and cost-effective removal of SO_2. The chemistry of the solution is also lost due to oxidation with open air environment when the units are idled during outages or on MISO reserve shutdown. Specifically, prior to bringing a unit back on-line, the chemical solution often requires a costly chemical recharge. to ensure adequate potency to remove SO_2. – this process can take up to 24 hours to correct the balance of the chemical solution, which has resulted in compliance issues during unit start up.

Finally, the A.B. Brown Dual Alkali scrubbers produce a waste known as filter cake. Although Petitioner has made several efforts to find a way to beneficially reuse this material, there is currently no cost-effective solution. When the A.B. Brown units 1 & 2 are operating, CEI South employees load dump trucks with the filter cake by-product 24/7 and place the filter cake in an on-site landfill that requires further development and expansion as well as continued maintenance and environmental monitoring. The current developed portion of the landfill is scheduled to run out of space by the end of 2023. As described by Witness Retherford, developing the only remaining permitted landfill location will require a permit modification to comply with the CCR regulations. The development of this area will be much more expensive than previous sections of the landfill due to topography and CCR requirements.

Q. Please explain the process utilized by Petitioner to identify replacement options for the Dual Alkali FGD Scrubbers.

A. A.B. Brown unit 1 will be 45 years old and A.B. Brown unit 2 will be 38 years old in 2023 when the units are planned to be retired. In consideration thereof, CEI South employed outside engineering consultants to research options for removal of SO_2 from the stack plumes at the then current required emission rates. Based on their experience and previous work related to scrubbing technologies, Petitioner engaged AECOM, Burns & McDonnell, and Black and Veatch to collectively research and obtain cost estimates for viable scrubbing options. Black & Veatch filtered, and summarized, the information collected. Of eight options considered, four were eliminated due to inability to reliably meet the SO_2 removal requirements.

Q. Please describe the scrubbing options considered.

A. Table WDG-2~~1~~ (below) shows the eight options researched and four considered for further evaluation. Capital and ongoing operation and maintenance costs were estimated and modeled for the four options as part of the 2019/2020 IRP to determine which was the lowest cost long-term option. This estimated cost was used in the 20-year modeling of continuing to operate A.B. Brown (Business as Usual or "BAU") scenario for the 20-year IRP period. For each of the four viable options, there are different by-products produced that create assorted opportunities as well as safety and storage challenges that were considered. Due to the Commission's feedback regarding not relying on off-system sales of energy, the Company felt it was not prudent to rely on potential by-product sales as part of the decision on future scrubbing technology.

the CTs?

A. The A.B. Brown Site does have adequate transmission and water service as a result of the A.B. Brown generating facility that is already located at the site. As mentioned earlier, the site contains a 138kV and a 345kV switchyard that directly connects the A.B. Brown Site to the electric grid. The site has a well reservoir with three pumps that provide up to 6,000 GPM for potable water, fire protection system water, and water for the reverse osmosis system to supply the evaporative coolers and other service water requirements. CenterPoint Indiana South completed construction of a 345kV transmission line and switchyard as a MISO Multi Value Reliability Project in 2010 that increases the ability to transmit energy from the A.B. Brown site into the transmission system. As described in the direct testimony of Petitioner's Witness Grizzle~~Kenny~~, a pipeline to be permitted and constructed by TGT will be used to supply the necessary firm natural gas capacity. Petitioner's Witness Rice explains the inclusion of the cost of this pipeline in the IRP modeling.

Q. Are there other benefits to CenterPoint Indiana South's customers by having the CTs interconnected with CenterPoint Indiana South's transmission system?

A. Yes. As mentioned earlier, this allows CenterPoint Indiana South to use the existing MISO interconnect rights currently held by the A.B. Brown location. This avoids the risk of a large expense for transmission upgrades if the CTs were to be constructed at another site. The interconnect rights can only be held for a three-year period and will be lost if not used within that time period. It also avoids the long MISO generation interconnect approval process that can take up to three years and keeps property tax base within the CenterPoint Indiana South service area.

V. COST ESTIMATE, PROCUREMENT PROCESS AND SCHEDULE for CTs

Q. How did CEI South establish a cost estimate for modeling the F Class CTs in the IRP?

A. The cost estimate for F Class CTs, like all other natural gas options, was taken from the Technology Assessment completed by Burns & McDonnell ("B&McD") and used in the modeling scenarios to help determine the Preferred Portfolio. Witness Rice describes the

Q. Will the proposed A.B. Brown Pond be useful after the A.B. Brown coal units are retired?

A. Yes. Water flows received in this pond after the A.B. Brown units are retired include landfill runoff leachate, coal pile runoff until decommissioning and clean-up is complete, , contact storm water from coal units until decommissioning is complete, and continued mercury treatment and possibly existing ash pond water. The pond will also receive oily wastewater and storm water runoff from the CT's as well as sanitary wastewater from the administrative and other office and storage buildings that will support the CT's.

Q. Is CEI South seeking a CPCN with respect to the proposed F.B. Culley and A.B. Brown CCR Part A Rule compliant ash ponds under IC 8-1-8.4-7?

A. Yes. The construction of the new ash ponds is necessary to comply with the CCR rule as described in greater detail by CEI South Witness Retherford and is therefore a compliance project within the meaning of IC 8-1-8.4-2. CEI South is seeking a CPCN in order to recover federally mandated costs associated with the project.

Q. How does CEI South plan to recover the costs associated with the proposed F.B. Culley and A.B. Brown CCR-compliant ponds as required per CCR Part A Rule?

A. CEI South witness Gostenhofer describes the proposed ratemaking and accounting treatment. Generally, project costs up to 80% will be recovered annually through the Environmental Cost Adjustment ("ECA") filing. The remaining 20% will be recovered through the next CEI South electric rate case.

Q. Do these ponds potentially affect the timing of the closure of F.B. Culley 2 or Warrick Unit #4 ?.

A. Yes for F.B. Culley 2 but no for Warrick #4. As described in greater detail by Petitioner's Witness Angila Retherford, the Culley pond offers Petitioner the opportunity, subject to certain conditions, to evaluate operating F.B Culley 2 through 2025, thereby reducing the volume and time Petitioner would otherwise be required to rely on the capacity and wholesale energy markets during its generation transition period. Because this new CCR compliant pond must be constructed to qualify for an extension to continue to use the east ash pond through October 2023~~5~~, and it is possible to use this new CCR compliant pond for continued disposal of the small amount of bottom ash generated by Culley Unit 2, it

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SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a CENTERPOINT ENERGY INDIANA SOUTH
(CENTERPOINT INDIANA SOUTH)

IURC CAUSE NO. 45564

DIRECT TESTIMONY
OF
MATTHEW A. RICE
DIRECTOR OF INDIANA ELECTRIC REGULATORY AND RATES

ON

INTEGRATED RESOURCE PLAN, NECESSITY OF THE COMBUSTION TURBINES PROJECT AND RATEMAKING ISSUES

SPONSORING PETITIONER'S EXHIBIT NO. 5 (~~CONFIDENTIAL~~PUBLIC)

ATTACHMENTS MAR-1 THROUGH MAR-16

DIRECT TESTIMONY OF MATTHEW A. RICE

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Matthew Rice. My business address is 211 NW Riverside Drive, Evansville, Indiana 47708.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting testimony on behalf of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("Petitioner", "CenterPoint Indiana South", or "Company"), which is an indirect subsidiary of CenterPoint Energy, Inc.

Q. What is your role with respect to Petitioner?

A. I am Director of Indiana Electric Regulatory and Rates.

Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Business Administration from the University of Southern Indiana in 1999. I also received a Master of Business Administration from the University of Southern Indiana in 2008.

Q. Please describe your professional experience.

A. Prior to working for CenterPoint Indiana South, I worked as a Market Research Analyst for American General Finance for six years working primarily on customer segmentation, demographic analysis, and site location analysis. In 2007, I joined the Company as a Market Research Analyst, and have held various positions of increasing responsibility, including Senior Analyst, Manager of Market Research, and Director of Research and Energy Technologies. Since 2009, I have been responsible for long-term energy forecasting for the Company's IRPs, helping to manage the Company's 2011, 2014, 2016, and 2019/2020 IRPs. I have also managed its IRP stakeholder process since 2014. My duties have included conducting economic analysis, primary and secondary customer research (including surveying, focus groups, segmentation, and demographic analysis), customer satisfaction research, housing market research, and monitored industry research. In February 2019, I became Manager of Resource Planning with responsibility for internal and external generation analysis and reporting. I was named to my current position of Director of Indiana Electric Regulatory and Rates in October 2020.

Q. What are your present duties and responsibilities as Director of Indiana Electric Regulatory and Rates?

A. I am responsible for Petitioner's electric regulatory and rate matters in regulated proceedings before the Indiana Utility Regulatory Commission ("Commission"). I also have responsibility for resource planning and reporting for CenterPoint Indiana South, including the IRP.

Q. Have you previously testified before the Indiana Utility Regulatory Commission ("IURC" or "Commission")?

A. Yes. I testified before the Commission in support of CenterPoint Indiana South's Certificate of Public Convenience and Necessity ("CPCN") in Cause No. 45052, and Petitioner's request for approval of a tariff rate for Excess Distributed Generation in Cause No. 45378. Additionally, I recently provided written testimony in Cause No. 45501, Cause No. 44910-TDSIC-8, Cause No. 44909-CECA 3, and in Cause No. 45052-ECA 2.

II. PURPOSE & SCOPE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony describes the analysis and results of CenterPoint Indiana South's 2019/2020 Integrated Resource Plan ("2019/2020 IRP") process. I summarize and respond to comments made in the draft Director's report issued on April 12, 2021. In addition, I describe and support CenterPoint Indiana South's request for a CPCN to construct two combustion turbines ("CTs") at the A.B. Brown site to replace A.B. Brown coal units 1 and 2 and testify that the proposed generation is consistent with the IRP. I describe how the cost of the A.B. Brown combustion turbines will be recovered in rates. Finally, I describe how customer rates are projected to be impacted by the Generation Transition Plan.

Q. Are you sponsoring any attachments to your direct testimony in this proceeding?

A. Yes. I am sponsoring the following attachments:

- Petitioner's Exhibit No. 5, **Attachment MAR-1**: CenterPoint Indiana South's 2019/2020 Integrated Resource Plan Volume 1 of 2
- Petitioner's Exhibit No. 5, **Attachment MAR-2 (CONFIDENTIAL)**: CenterPoint Indiana South's 2019/2020 Integrated Resource Plan Volume 2 of 2
- Petitioner's Exhibit No. 5, **Attachment MAR-3**: Low End Estimated Net Monthly Rate Impact by Customer Class
- Petitioner's Exhibit No. 5, **Attachment MAR-4**: High End Estimated Net Monthly Rate Impact by Customer Class
- Petitioner's Exhibit No. 5, **Attachment MAR-5**: Low End Estimated Net Monthly Rate Impact by Customer Class – Existing Allocations
- Petitioner's Exhibit No. 5, **Attachment MAR-6**: High End Estimated Net Monthly Rate Impact by Customer Class – Existing Allocations
- Petitioner's Exhibit No. 5, **Attachment MAR-7 (CONFIDENTIAL)**: Posey County Solar Project
- Petitioner's Exhibit No. 5, **Attachment MAR-8 (CONFIDENTIAL)**: Warrick County Solar Project
- Petitioner's Exhibit No. 5, **Attachment MAR-9 (CONFIDENTIAL)**: 335 MW Solar PPA Projects
- Petitioner's Exhibit No. 5, **Attachment MAR-10 (CONFIDENTIAL)**: 200 MW Wind PPA Project
- Petitioner's Exhibit No. 5, **Attachment MAR-11**: 2 Combustion Turbine Project
- Petitioner's Exhibit No. 5, **Attachment MAR-12 (CONFIDENTIAL)**: 130 MW Owned Solar
- Petitioner's Exhibit No. 5, **Attachment MAR-13 (CONFIDENTIAL)**: 150 MW Wind Project
- Petitioner's Exhibit No. 5, **Attachment MAR-14**: BAU 2029 – Continue ABB1 & ABB2 Project
- Petitioner's Exhibit No. 5, **Attachment MAR-15**: Conversion of ABB1 & ABB2 Coal to Gas Project

Q. Were these attachments prepared by you or under your direction?

A. Yes, they were. The Company's 2019/2020 IRP process was managed under my direction or supervision, although it is important to recognize that other Company employees and consultants with specific areas of expertise engaged by the Company were involved in the process of developing the 2019/2020 IRP. In addition to these attachments, I am also sponsoring Petitioner's Exhibit No. 5, Attachment MAR-16, which was prepared by the Commission and is its 2018 Report of the Statewide Analysis of Future Resources for Electricity.

III. CENTERPOINT INDIANA SOUTH'S 2019/2020 IRP PROCESS

Q. Please describe how CenterPoint Indiana South approached the 2019/2020 IRP.

A. The 2019/2020 IRP was CenterPoint Indiana South's most detailed resource planning analysis process. The Company worked with several industry experts to conduct the technical analysis: Itron provided the long-term energy and demand forecast; 1898 and Company, a Burns and McDonnell company ("Burns and McDonnell"), worked with CenterPoint Indiana South to conduct an All-Source Request For Proposals ("All-Source RFP") and provide modeling inputs for various generating resources; Black and Veatch assisted with several studies utilized to evaluate numerous alternatives for existing resources; GDS provided Energy Efficiency modeling inputs; and Siemens PTI, formerly Pace Global Energy Services ("Siemens PTI"), provided scenario development, deterministic modeling, probabilistic modeling, and provided assistance with the risk analysis. A copy of Petitioner's 2019/2020 IRP is attached to my testimony as Petitioner's Exhibit No. 5, Attachments MAR-1 and MAR-2 (CONFIDENTIAL).

Q. What process did Petitioner use in developing the 2019/2020 IRP?

A. Petitioner began the process by reviewing stakeholder comments from the 2016 IRP, including the Director's Report, and by carefully reviewing the Commission Orders issued in connection with Petitioner's requests for CPCNs in Cause Nos. 45052 (F.B. Culley 3 upgrades and Combined Cycle Gas Turbine ("CCGT")) and 45086 (50 MW Troy solar). This feedback was used to formulate twelve continuous improvement commitments that were shared with CenterPoint Indiana South IRP stakeholders in our first public stakeholder meeting on August 15, 2019, and fulfilled on June 30, 2020, with the submission of the 2019/2020 IRP. In the first stakeholder meeting, CenterPoint Indiana South presented the analysis plan and laid out all topics to be discussed with stakeholders for each of CenterPoint Indiana South's public stakeholder meetings. Figure 3.1 "2019/2020 Stakeholder Meetings" on page 110~~08~~ of the IRP, Petitioner's Exhibit No. 5, Attachment MAR-1, details the topics discussed in each meeting, summarized in Figure 1 below.

Figure 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

The general process involved presenting information and gathering feedback from stakeholders on key topics, including but not limited to the following: objectives, scorecard development, forecasts, modeling inputs, scenario development, portfolio development, technical modeling, and results. At the beginning of each stakeholder meeting, CenterPoint Indiana South made a point to follow up with stakeholders on input provided in the prior meeting. Often stakeholder feedback was utilized, but in instances where it was not, CenterPoint Indiana South discussed why it was not used. The planning analysis began with an All-Source RFP, which was conducted simultaneously with the IRP and was utilized as an input into modeling for resource selection/portfolio development. Objectives were presented at the first meeting. Scorecard development also began at this meeting and was refined throughout the process based on stakeholder feedback and evaluation of measures to ensure that each was a good representation of the risk factor it represented. Scenarios (potential future states) then were developed with stakeholder input for use in deterministic modeling. Portfolios (combinations of resource options to meet customer load over the evaluation period) were then developed with stakeholder input. Care was taken to ensure a wide range of scenarios and portfolios were utilized and evaluated within the IRP analysis, respectively. These portfolios then were modeled and evaluated within the deterministic futures and within probabilistic simulation of 200 potential futures (also referred to as stochastic modeling). CenterPoint Indiana South utilized quantitative and qualitative information produced within this analysis to select a preferred portfolio.

Q. Please describe the role of the All-Source RFP within the IRP.

A. Per Commission feedback in Cause No. 45052, CenterPoint Indiana South, with the help of Burns and McDonnell, conducted an All-Source RFP to gather resource availability and pricing information for various resources, particularly emerging resources such as solar, solar + storage, and standalone storage. Results of the All Source RFP were summarized into modeling inputs for the IRP for solar, solar + storage, standalone storage, and wind.

Q. What steps did CenterPoint Indiana South take to ensure that pricing included within modeling was as accurate as possible?

A. Care was taken to help ensure up-to-date and accurate information was included within modeling. For example, only projects that provided a firm price and were either on CenterPoint Indiana South's system or included a delivered price were included within modeling inputs. These were referred to as Tier 1 projects within the IRP.

> Proposals were divided into two tiers, based on factors that could add cost risk to [CenterPoint Indiana South] customers. Tier 1 Proposals were those that included binding pricing and delivery of energy to SIGE.SIGW ([CenterPoint Indiana South's] load node) or were physically located in [CenterPoint Indiana South'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 [CenterPoint Indiana South's] system, which increases cost risk due to congestion. Despite these risks, several were still analyzed and considered during the RFP evaluation process; however, [CenterPoint Indiana South] wanted, to the extent possible, to include

> bids with more price certainty within the IRP modeling in order to protect customers from price volatility.

Petitioner's Exhibit No. 5, Attachment MAR-1 at 155~~3~~.

Burns and McDonnell took care to understand the bids and include all relevant costs, including known transmission upgrades. This involved communications between Burns and McDonnell and bidders to clarify information provided within the bid. Relevant data was provided to Burns and McDonnell via a standardized template to help keep information consistent among bids.

Q. Were bids for traditional fossil fuel resources used to create modeling inputs?

A. No, CenterPoint Indiana South received two bids for 100 MW coal PPAs (5 and 10 years), and several bids for mid-sized to large natural gas CCGTs. None were Tier 1 bids and therefore were not modeled. No bids were received for CTs. For new traditional fossil fuel resources, CenterPoint Indiana South relied on a technology assessment from Burns and McDonnell for cost and operational data, found in IRP Vol. 2~~1~~, Petitioner's Exhibit No. 5, Attachment MAR-2~~1~~.

Q. Did you receive any Demand Response bids?

A. Yes, CenterPoint Indiana South received only one bid for a demand response resource. It was for 50 MWs over a 6-year duration and covered the years where there was not a capacity need (2021 – 2022). Capacity was modeled as a potential resource within the IRP. The cost of this bid was higher than the capacity price forecast utilized within the IRP.

Q. Was cogeneration considered?

A. Yes. However, we did not receive any Tier 1 bids for cogeneration, so cogeneration was not an option to be selected in the near term. In the long-term, Combined Heat and Power ("CHP") was considered but not selected.

Q. Did you consider joint ownership of any facilities?

A. Yes, we approached other electric utilities in Indiana about jointly owning generation. No partnership opportunities materialized.

Q. Did you conduct a full Levelized Cost of Energy ("LCOE") screening analysis to

exclude technologies from being modeled?

A. No. In the 2016 IRP, an LCOE screening analysis was necessary because of the use of Strategist modeling software, which could not analyze multiple resources options at one time. The screening analysis removed resources that were not cost effective, prior to modeling to improve efficiency. There was no need to conduct a full LCOE analysis in the 2019/2020 IRP, as the Aurora model was able to consider many options at one time. This was responsive to the Commission's findings in Cause No. 45052 that ". . . multiple less expensive alternatives" were screened out. Only two options were excluded prior to modeling: aeroderivative natural gas combustion turbines due to high-pressure gas supply; and reciprocating natural gas engines due to high cost. In addition to multiple existing unit options (continue coal, retire coal, or conversion), the model was able to consider a large number of new options simultaneously, including: hydroelectric, wind, wind plus storage, solar, solar plus storage, lithium-ion battery storage, flow battery storage, energy efficiency, demand response, coal, biomass, landfill gas, combined heat and power, combined cycle gas, and simple cycle gas.

Q. What forecasts did CenterPoint Indiana South use in its 2019/2020 IRP?

A. Multiple forecasts were used as an input to the analysis to first develop a Reference Case. As described in Petitioner's Exhibit No. 5, Attachment MAR-1 Section 2.4.1 of the IRP, pages ~~8~~91-93~~1~~, CenterPoint Indiana South relied on several industry experts for key inputs in the IRP analysis. For coal, gas, market capacity price forecasts, and long-term emerging resource costs, a consensus forecast was used. For natural gas and coal, CenterPoint Indiana South created an average price using data from PIRA Energy Group, Wood Mackenzie, Siemens PTI, ABB, and Energy Ventures Analysis ("EVA"). For the MISO Zone 6 capacity value, CenterPoint Indiana South created an average, utilizing Siemens PTI, ABB, and Wood Mackenzie forecasts.[1] The long-term capital price forecast (beyond 2024) for emerging supply side resources was based on the average of National Renewable Energy Laboratory ("NREL"), Burns and McDonnell, and Siemens PTI forecasts. Siemens PTI developed the carbon price forecast. Itron developed the energy and demand forecast. GDS created a price forecast for demand side resources. Siemens PTI utilized both AURORAxmp power dispatch model with Reference Case inputs and

[1] CenterPoint Indiana South did not have access to a capacity forecast from PIRA or EVA.

expectations for the broader market to generate on-peak and off-peak power prices in the MISO region. To create varying inputs for scenarios, CenterPoint Indiana South worked with stakeholders to determine how key inputs would vary by scenario in the short-, mid-, and long-term based on narrative-based futures. This process helped ensure multiple perspectives were captured and used to create a wide range of potential futures. Siemens PTI used probabilistic distributions and adjusted Reference Case forecasts for each scenario in conjunction with stakeholder guidance, where reasonable.

Q. In your opinion, were the forecasts used by CenterPoint Indiana South reasonable?

A. Yes. Following the 2016 IRP, CenterPoint Indiana South was praised in the Director's report for using consensus forecasts where possible to increase transparency for stakeholders and incorporate multiple views from credible sources. CenterPoint Indiana South continued using consensus forecasts to develop the 2019/2020 IRP. Other inputs provided by expert third-party sources were shared and discussed as part of the stakeholder process. Forecasts were also compared with publicly available forecasts, such as the Energy Information Administration's Annual Energy Outlook, for reasonableness.

Q. Did CenterPoint Indiana South consider stakeholder input received at the Company-specific meetings?

A. Yes. CenterPoint Indiana South held three workshops as part of these meetings designed to solicit input from stakeholders that was incorporated into the IRP planning process. The fourth public meeting included a preview of the Preferred Portfolio. CenterPoint Indiana South described how stakeholder input received at the prior stakeholder meeting was utilized in each meeting. Where feedback was not used, CenterPoint Indiana South explained the reasoning. Feedback from stakeholders helped shape the analysis in significant ways, including but not limited to: scorecard development (identification and inclusion of key risks including considering full life cycle of CO_2e), scenario development, expected MISO accreditation of resources, fuel price forecasts, consideration of a wide range of portfolios, and use of an All-Source RFP.

Q. Did you incorporate stakeholder input into the portfolio development process?

A. Yes. CenterPoint Indiana South incorporated stakeholder input prior to and during the

2019/2020 IRP analysis. Continuous improvement of the resource planning analysis was integral to CenterPoint Indiana South's 2019/2020 IRP. CenterPoint Indiana South learned from the last IRP that stakeholders were interested in utilizing least cost optimization to help ensure portfolio cost was as low as possible. In the third public stakeholder meeting held on December 13, 2019, CenterPoint Indiana South discussed each portfolio development strategy and described the relevant stakeholder input used to help develop portfolios. Examples of stakeholder input considered included, but were not limited to: explore options at A.B. Brown, make adjustments to various scenarios, explore conversion options, run A.B. Brown until 2029, run A.B. Brown until 2039, do not run fossil fuel plants beyond 2030, consider smaller CCGT options, and consider flexible gas CTs and renewables.

Q. How did CenterPoint Indiana South develop the portfolios modeled in the 2019/2020 IRP?

A. CenterPoint Indiana South worked with stakeholders to consider and utilize strategies to develop a wide range of portfolios. Five portfolio development strategies were discussed with stakeholders: (i) Status Quo (i.e., continue running existing units), (ii) Scenario-Based (i.e., least cost optimization), (iii) Bridge (i.e., continued use of A.B. Brown assets), (iv) Diverse (i.e., diverse energy with renewables, gas, and coal), and (v) Renewables Focused (i.e., much less to no reliance on fossil fuel resources). Except for the Scenario-Based portfolio development strategy, various resource options were locked in, and deterministic modeling was utilized to select the most economical way to meet the remaining capacity and energy obligations. For example, under the Bridge portfolio development strategy, the Brown units would continue to run with the existing scrubber through 2029, and the model determined the replacement to meet MISO's planning reserve margin requirements and optimized for lowest net present value of revenue requirements ("NPVRR"). The Scenario-Based portfolio options were created for each of the five deterministic scenarios. In this process, existing coal units[2] were evaluated for economic retirement. Ultimately this process produced fifteen distinct portfolios, ranging

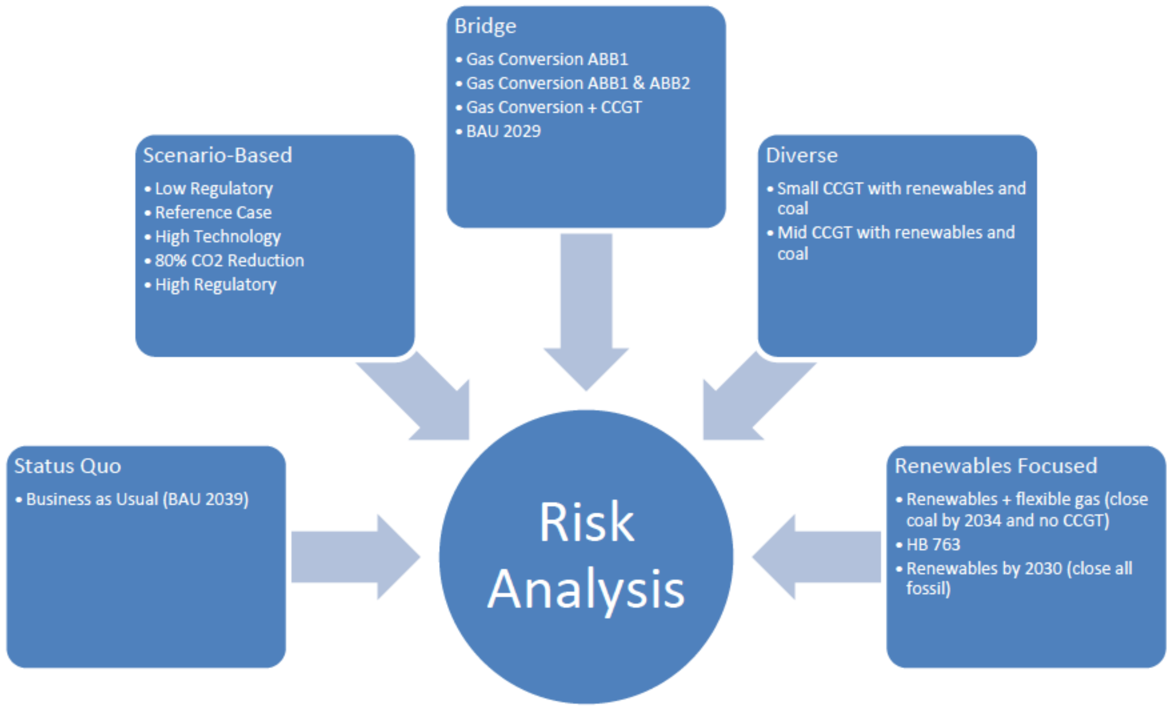
[2] A.B. Brown units 1 & 2, F.B. Culley 2, and Warrick Unit #4. Warrick Unit #4 is a jointly operated plant with Alcoa Power Generating, Inc. ("Alcoa"). The current contract expires at the end of 2023, leaving a 150 MW capacity shortfall currently in all portfolios. CenterPoint Indiana South modeled a potential 3-year extension of the contract; it was not selected based on economics.

from continuing most coal resources through the end of the forecast to an all-renewables portfolio by 2030.

Q. Please summarize the fifteen optimized portfolios that CenterPoint Indiana South examined.

A. Fifteen portfolios were created utilizing the process described above. Figure 2 below is a visual representation of the wide range of portfolios analyzed, bucketed by five portfolio development strategies: Status Quo, Scenario-Based, Bridge, Diverse, and Renewables Focused. A brief description of each strategy follows below. A Status Quo portfolio identified as Business as Usual ("BAU") through 2039 was included as a bookend. This portfolio included continuing to run all coal plants, except for Warrick Unit #4, through 2039. Five Scenario-Based portfolios were created (one per scenario) for the following scenarios: Reference Case, Low Regulatory, High Technology, 80 percent reduction of CO_2 by 2050, and High Regulatory. Each of these potential future states were optimized to produce a least cost portfolio in each future state. Four Bridge portfolios were created to explore options to continue to utilize existing equipment at the A.B. Brown plant. These portfolios included converting one unit to gas, converting two units to gas, converting one unit to gas with the addition of a small CCGT, and continuing to run both units with coal through 2029. Two Diverse energy portfolios were created: one with a small CCGT and the other with a mid-sized CCGT. These portfolios were included to explore options that produce a balanced mix of energy from coal, gas, and renewable resources. Finally, three Renewables Focused portfolios were created. The first was a Renewables Plus Flexible Gas portfolio, which involved closure of all coal units by 2034 and included gas CTs, renewables, and storage. The House Bill 763 portfolio was created with a very high CO_2 price per stakeholder input. The other bookend portfolio was to close all fossil fuel plants by 2030.

Figure 2: Portfolios by Strategy



All portfolios included demand side resources (i.e., Energy Efficiency and Demand Response). It should also be noted that the model selected a significant amount of wind and solar resources in all portfolios (300 MWs of wind and 1,150 MWs of solar before 2025), including the BAU portfolios, in part to replace Warrick Unit #4, but also because these resources lowered the NPVRR due to their production of low cost energy.

Q. Please describe the role of CO_2 in your analysis.

A. One of the biggest risk factors considered in this analysis was CO_2 output. Scenarios, potential future states, were constructed using various regulatory environments including alternate paths for CO_2. The Low Regulatory scenario only included the Affordable Clean Energy (ACE) rule, which required upgrades at coal plants to improve efficiency. The Reference Case assumed ACE would be repealed and replaced with a modest CO_2 tax beginning in 2027. As mentioned in Petitioner's Witness Angila M. Retherford's testimony, ACE has since been vacated in court. The High Technology scenario assumed a low CO_2 tax beginning in 2025. The 80% Reduction of CO_2 by 2050 includes a CO_2 cap and trade price that is consistent with the Paris Accords, designed to achieve an 80% reduction in

CO_2 by 2050 from 2005 levels. Finally, the High Regulatory scenario includes an extremely high CO_2 tax beginning in 2022. Table 1 below shows a visual summary of each scenario.

Table 1: Scenario Summary Table

	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

Additionally, CenterPoint Indiana South worked with Siemens to incorporate a CO_2 equivalent measure for lifetime life cycle emissions for the score card. This measure included cradle to grave emissions for each portfolio, including, but not limited to, emissions associated with building the resource, getting it on site, methane leakage from the well head, emissions out of the stack, and decommissioning. Generation was tracked by resource and was multiplied by a CO_2e factor supplied by NREL. In this way, CO_2e was one trade off considered within the scorecard.

CO_2 prices were also utilized within stochastic modeling. Each portfolio was modeled in 200 potential future states to capture the cost of each portfolio and cost risk. A wide range of CO_2 prices were included in the net present value and the 95th percentile net present value[3] of each portfolio. The higher the CO_2 output for a portfolio, the higher the portfolio cost and cost risk.

Q. What were the CO_2 prices used within scenario modeling?

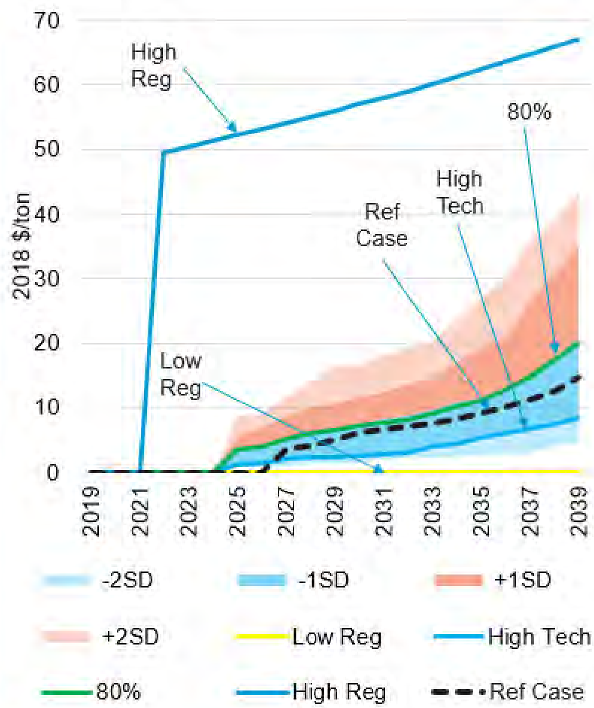
A. CenterPoint Indiana South included a wide range of CO_2 prices within scenario modeling

[3] 95th percentile of NPVRR (million$) across 200 dispatch iterations under varying market conditions. Used to illustrate the upper end cost risk for each portfolio within the IRP scorecard. Simply put, there is a 5% chance costs could go above this level.

to help understand the potential costs of future regulations to customers. The Preferred Portfolio preformed consistently well across multiple potential future states. Figure 3 below shows CO_2 cost modeled within each deterministic scenario.

Figure 3: Scenario CO_2 Costs

	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

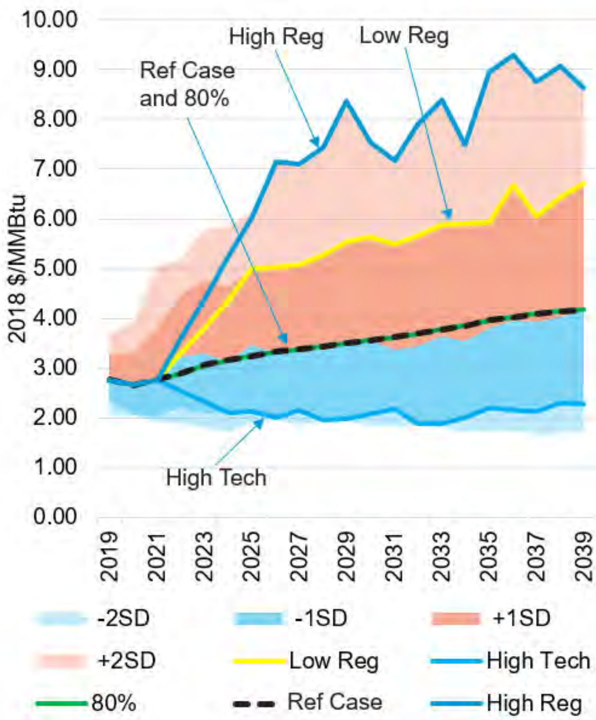


Q. What were the gas prices used within scenario modeling?

A. CenterPoint Indiana South modeled a very wide range of gas prices, including the High Regulatory scenario, which varied gas prices by two standard deviations. This was based on Commission guidance in Cause No. 45052 to fully explore risks of higher gas prices. The High Regulatory scenario assumes a fracking ban that drives supply down and prices dramatically up. Figure 4 below shows the range of gas prices modeled in the 2019/2020 IRP within each deterministic scenario.

Figure 4: Scenario Natural Gas Costs

	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



Q. What analyses did CenterPoint Indiana South use to determine the Preferred Portfolio?

A. CenterPoint Indiana South worked with Siemens PTI to conduct a multi-facetted risk analysis, which included evaluating portfolios on a quantitative and qualitative basis. After creation of the fifteen portfolios, each portfolio was evaluated utilizing simulated dispatch in the Reference Case. Several portfolios included fatal flaws and were excluded from further consideration. As described in more detail in Petitioner's Exhibit No. 5, Attachment MAR-1 Section 8.2 Evaluation of Portfolio Performance, on pages 245-246~~3~~ of the IRP, these included the HB 763, Low Regulatory, High Regulatory, 80 percent reduction of CO_2, and the Diverse Energy Mid-sized CCGT portfolio. Reasons for the exclusion of these portfolios included high net sales, high market exposure, high cost, or redundancy. The remaining ten portfolios were then dispatched in each deterministic scenario to determine performance among a wide range of potential future states. Some portfolios performed very consistently in terms of cost across each scenario, including the Reference Case, preferred portfolio, and Renewables Plus Flexible Gas. Others, like the BAU portfolio or the all renewables portfolio had much greater cost variation relative to the Reference Case across each potential future. Next, the remaining ten portfolios were dispatched 200 times under varying market conditions. Information gathered from this modeling was then utilized to populate the balanced scorecard, which was developed with stakeholder input. The balanced scorecard included quantitative measures to help CenterPoint Indiana South understand tradeoffs among competing objectives of the IRP; these included stochastic mean 20-year NPVRR (cost), 95th Percentile Value of NPVRR (cost risk), Percent Reduction of CO_2e (life cycle emissions reduction including CO_2, methane and other emissions on a CO_2 equivalent basis), long-term percentage reliance on the energy market for sales or purchases, and long-term percentage reliance on the capacity market for sales and purchases. Table 2 below shows a summary of these measures.

Table 2: Quantitative IRP Scorecard Objectives and Metrics

Objective	Metric
Affordability	Mean value for the 20-Year Net Present Value of Revenue Requirements (NPVRR) (million$) across 200 dispatch iterations under varying market conditions
Cost Uncertainty Risk Minimization	95th percentile of NPVRR (million$) 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 (%) and Annual Capacity Sales and Purchases, divided by Total Resources, average (%)

Six portfolios (five included continued use of A.B. Brown with coal or conversion options and the remaining CCGT option), which were highest in cost and cost risk, were removed from consideration at this point based on their overall performance on scorecard measures and other qualitative considerations discussed at the last stakeholder meeting on June 15, 2020. Four competitive options remained for further analysis and consideration: (i) the Reference Case, (ii) Renewables Plus Flexible Gas, (iii) Renewables by 2030, and (iv) the High Technology portfolio. Table 3 below provides details regarding each portfolio.

Table 3: Portfolio Detail

Year	Reference Case	Renewables + Flexible Gas	Renewables by 2030	High Technology
2021-23	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)
2023	New Solar (731 MW), New Storage (126 MW)	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (278 MW)	New Solar (731 MW) New Storage (126 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)
2024	New Combustion Turbine (236 MW)	New Combustion Turbine (236 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
2024-26	0.75% Energy Efficiency	0.75% Energy Efficiency	1.00% Energy Efficiency	0.75% Energy Efficiency
2025		-	-	New Combustion Turbine (236 MW)
2027-39	0.75% Energy Efficiency	0.75% 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)	-
2033-39	New Solar (250 MW)	Retire FBC3 (270 MW), New Combustion Turbine (236 MW)	New Solar (450 MW)	New Storage (50 MW)
2024-39	Average Annual Capacity Market Purchases (137 MW)	Average Annual Capacity Market Purchases (135 MW)	Average Annual Capacity Market Purchases (170 MW)	Average Annual Capacity Market Purchases (4 MW)

Q. **Within scenario-based optimization was any coal unit selected to continue running based on economics?**

A. No. Every scenario retired 730 MWs of coal, including the Low Regulatory Scenario which was favorable to coal resources. As shown in Table 1 above, the Low Regulatory Case included no price for CO_2[4], low coal cost (declining and below $1.80 per MMBTu), higher load than the Reference Case, and higher gas prices than the Reference Case.

Q. **What were the results of the scorecard process?**

A. Of the four remaining portfolios, the High Technology portfolio performed well across all risk factors. Within the IRP, the cost was listed as being within 2.5 percent of the lowest cost portfolio, the Renewables Plus Flexible Gas. The Renewables Plus Flexible Gas portfolio retires F.B. Culley 3 earlier than the High Technology portfolio thereby saving customers money. Both portfolios include about the same level of renewables and a second CT. As discussed in Petitioner's Witness Nelson Bacalao's testimony, this cost gap closes to 1.5 percent due to construction efficiencies that would be lost with building

[4] Minimal costs were included to comply with ACE, which has since been vacated.

the second CT ten years later under the Renewables Plus Flexible Gas option, which is not reflected within the IRP NPVRR. The Preferred Portfolio performed well in terms of cost risk relative to other portfolios. While the percent reduction of CO_2e was less than the renewables flexible gas and all renewables by 2030 portfolios, the Preferred Portfolio was near the middle of all portfolios and overwhelmingly driven by the continued use of F.B. Culley 3. As Witness Retherford explains, due to changes in environmental regulations, the Company is presently evaluating the decision to retire F. B. Culley 3 earlier than 2039. If the decision is made to retire F.B. Culley 3 early, the differences between the Preferred Portfolio and Renewables Plus Flexible Gas in terms of NPVRR and percent reduction of CO_2e are not expected to be material. Of the remaining portfolios, the Preferred Portfolio relied least on energy purchases and was among the best in terms of reliance on energy sales to the market. The Preferred Portfolio was dramatically better, at 0.4 percent, in terms of less long-term reliance on the capacity purchases, while the other three portfolios average reliance ranged from 9.4 to 11.9 percent per year. The Preferred Portfolio relied on capacity sales of 4.6 percent, which was in the middle of all portfolios.

Q. Please describe further why the Preferred Portfolio was selected.

A. The Preferred Portfolio was selected because it was determined to be a very reliable and resilient portfolio that offers a transition to a clean energy future by complementing renewable energy resources with fast start and fast ramping capability. The portfolio is a good mix of traditional and emerging resources and has enough dispatchable capacity to cover CenterPoint Indiana South's load in the winter when there is drastically less solar output during the winter peak period. This point is illustrated in Petitioner's Witness Bacalao's testimony. The Preferred Portfolio is cost effective and expected to save CenterPoint Indiana South's customers up to $320 million over the IRP's twenty-year planning period (2020 – 2039) compared to continuing to operate coal units. The Preferred Portfolio provides a physical hedge against high energy and capacity costs. As the future continues to be uncertain, this plan offers a diverse set of resources with multiple off-ramps, designed to hedge against risk of putting too much emphasis on a few large resources. While the flexible gas CTs are available to provide low cost capacity, their projected usage, largely limited to critical times, results in lower CO_2 emissions by 75 percent by 2035 over 2005 levels.

Q. Has modeling been updated since submitting the IRP on June 30, 2020?

A. No. CenterPoint Indiana South considered a wide range of potential future states within the IRP analysis to understand how the portfolios would perform if the future turns out to be different than expected. The result does not rely on a single set of assumptions that can later be invalidated by evolving market conditions. That being said, we have not seen the shifts in key inputs in recent years that would have changed the selection of the Preferred Portfolio. During the IRP, some market data suggested that solar costs may be going up. As described on page 103~~1~~ of the IRP in Petitioner's Exhibit No. 5, Attachment MAR-1 "[CenterPoint Indiana South] performed a sensitivity in which the cost of solar Power Purchase Agreement ("PPA") resources increase 30 percent, based on more recent market information at the time. 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." Secondly, the period between submitting the IRP and filing this CPCN is only about 1 year. While we have seen impacts due to COVID lock downs, it is too soon to know the long-term effects. While one might argue that load could be lower going forward, that does not negate the need for two combustion turbines. [redacted] It should be noted that the Commission recently found in NIPSCO Cause No. 45462 that the mere passage of time did not invalidate their 2018 IRP. The Commission went on to state that integrated resource plans are performed at a point in time and use modeled scenarios to show how resources perform over a variety of alternative future conditions. CenterPoint Indiana South's IRP sought to understand potential changes that could affect the electric industry[5].

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[5] The Commission, in its Order in Cause No. 45462, wrote: "The mere passage of time does not invalidate the 2018 IRP, nor does the fact that NIPSCO chose to submit three Solar Projects that represent its largest proposed investment to date. Inherently, integrated resource plans are performed at a point in time and use modeled scenarios to show how resources perform over a variety of alternative future conditions. This is not a case where NIPSCO performed the 2018 IRP analysis and has failed to respond to changes in the electric industry or the broader market, and now seeks approval of generation additions based on a questionable foundation." *Cause No. 45462* (IURC 5/5/2021), at p. 62

Q. Does the Preferred Portfolio rely heavily on the market for energy or capacity sales and purchases?

A. No. The Commission provided clear guidance in Cause No. 45052 that CenterPoint Indiana South should not ". . . have a one-sided view of market risk." As such, CenterPoint Indiana South included this key risk in the balanced scorecard. Portfolios that relied too heavily on the market for wholesale market sales or capacity sales were considered riskier than those that more closely aligned with retail need. Market energy and capacity sales have the effect of lowering the Net Present Value of Revenue Requirements. Effectively, portfolios that have high market energy and capacity sales are taking a chance at the customers' expense that the projected energy price will remain at or above projected levels. On the other side of the spectrum, portfolios that relied heavily on the market for long-term energy and capacity purchases were also deemed risky. Portfolios with sufficient resources to meet customer retail load and maintain sufficient capacity to meet long-term planning reserve margin requirements shield customers from market price risk. Overall, the Preferred Portfolio performed well on these score card measures.

Q. How did portfolios perform that included A.B. Brown continuation on coal or conversion to natural gas?

A. Five portfolios were created to explore options to continue utilizing existing generation at the A.B. Brown plant: BAU 2039 (continues use of Brown coal units through 2039), Bridge BAU 2029 (continues use of Brown coal units through 2029), Bridge ABB1 Conversion (conversion of 1 Brown unit to gas), Bridge ABB1 + ABB2 Conversion (conversion of both Brown coal units to gas), and Bridge ABB1 + CCGT (conversion of one Brown coal unit to gas with the addition of a mid-sized CCGT at stakeholder request). As shown in Table 4: IRP Scorecard below, these options were among the highest cost and cost risk. Additionally, portfolios that relied on continued coal burn relied the most on Market energy sales. Overall, these portfolios performed poorly compared to the Preferred Portfolio (High Technology), as shown below in Table 4: IRP Scorecard.

Table 4: IRP Scorecard[6]

	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%

	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	Excess Capacity as a % of Peak Demand
Reference Case	$2,536	$2,919	58.1%	16.8%	26.8%	9.7%	1.2%
BAU to 2039	$2,912	$3,307	35.2%	12.0%	36.5%	0.1%	11.1%
Bridge BAU 2029	$2,689	$3,090	61.9%	15.2%	31.4%	7.1%	4.3%
Bridge ABB1 Conversion + CCGT	$2,822	$3,217	47.9%	6.6%	31.8%	1.3%	10.1%
Bridge ABB1 Conversion	$2,632	$3,001	61.5%	19.2%	26.4%	9.3%	1.2%
Bridge ABB1 + ABB2 Conversion	$2,784	$3,161	61.5%	18.5%	27.5%	4.0%	5.6%
Diverse Small CCGT	$2,680	$3,071	47.9%	6.4%	31.1%	1.7%	3.7%
Renewables Peak Gas	$2,526	$2,926	77.4%	21.5%	27.7%	9.4%	1.2%
Renewables 2030	$2,613	$3,002	79.3%	26.1%	31.9%	11.9%	1.7%
High Technology	$2,590	$2,978	59.8%	16.7%	26.9%	0.4%	4.6%

Q. Have you reviewed the Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, which was published on April 9, 2021?

A. Yes. I have reviewed the report.

Q. Please describe the Director's Report.

A. Following submission of the IRP, Dr. Brad Borum Director of Research, Policy and Planning will submit a critique of the Company's IRP. The Director's Report is a tool that allows for Commission staff to provide direct feedback on the stakeholder process, analysis methodology, compliance with the rule, and clarity of communication materials, including the IRP report. Within the Director's draft report, there is also a synthesis of

[6] Includes updated Stochastic Mean 20-Year NPVRR and 95th Percentile Value of NPVRR to reflect final IRP results including corrections to 3 conversion portfolios. Additionally, Purchases as a % of Peak Demand and Excess Capacity as a % of Peak Demand for the ABB1 Conversion were inverted.

stakeholder comments that were provided on the Company's IRP with feedback from the Director. CenterPoint Indiana South utilizes this report to drive continuous improvement in our IRP analysis. Feedback from the prior Director's Report addressing CenterPoint Indiana South's 2016 IRP was discussed in the first of four public stakeholder meetings and informed a wide range of improvements in the 2019/2020 IRP.

Q. Please describe the major concerns raised in the 2016 Director's Report.

A. The Director raised four major concerns about the 2016 IRP in that Director's report: 1) CenterPoint Indiana South did not consider a wide range of portfolios; 2) CenterPoint Indiana South did not consider a wide enough range of gas price forecasts; 3) CenterPoint Indiana South did not perform a comprehensive risk analysis; and 4) modeling methodology concerns were raised.

Q. Were these concerns addressed in the 2019/2020 IRP?

A. Yes. The Director did not raise these issues in the 2019/2020 IRP. In fact, he had several positive comments, many of which were in these areas. On page 25 of the draft report, the Director noted that "[CenterPoint Indiana South]'s IRP included significant advances to its processes, analysis, methodology, and software. The Director appreciates the significant changes [CenterPoint Indiana South] has made from its 2016 IRP."[7] The Director also commented on page 21 that the "…Risk and uncertainty analysis and discussion in the IRP are well done."[8] Additionally, it was noted on page 21 of the draft report that "The Director appreciates the wide range of alternative candidate portfolios that were partially optimized. Each was clearly designed to evaluate specific alternative resource strategies. Emphasis was placed on the conversion of one or both Brown units

[7] Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, April 9, 2021, by Dr. Bradley Borum, Director of Research, Policy and Planning on behalf of the Indiana Utility Regulatory Commission, Page 25.

[8] Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, April 9, 2021, by Dr. Bradley Borum, Director of Research, Policy and Planning on behalf of the Indiana Utility Regulatory Commission, Page 21.

to natural gas and the acquisition of 400-500 MW of natural gas combined cycle capacity. The information from this analysis is helpful . . ."[9]

Q. Were any concerns raised about the 2019/2020 IRP?

A. Yes. The Director emphasized two concerns within the Director's draft report, . both of which I will address here. First, as indicated page 32 of the draft report:

> The Director agrees with the OUCC that the large increase in projected industrial sales in the next few years looks unusual. Utilities often make an adjustment in the first few years of an industrial load forecast to account for large changes that are thought to be missed by an econometric forecast that emphasizes historical trends and relationships. The issue of how to account for large near-term changes in load is not new.[10]

As described in the IRP, CenterPoint Indiana South utilized its internal estimate for large sales in the first 5 years of the forecast and then relied on modest long-term annual growth estimates thereafter. This process ensures that CenterPoint Indiana South captures large, expected shifts in load, up or down, based on conversations/negotiations with CenterPoint Indiana South's largest active and prospective customers. Estimates from large customers not only feed CenterPoint Indiana South's integrated resource planning but also the company budget and are submitted to MISO. CenterPoint Indiana South only includes projects with the most certainty within the forecast. Large shifts in load must be accounted for outside of econometric modeling. For example, when a large customer recently installed a co-generation facility, there was a drop of about 80 MWs in the year that it was installed. CenterPoint Indiana South included the expected reduction in sales and demand within the forecast. A drop of this magnitude cannot be predicted within econometric modeling, nor is it reflective of potential future drops in large customer sales. Additionally, CenterPoint Indiana South continues to engage in confidential negotiations with potential customers for large load additions, [redacted]. This large load was not included within the IRP forecast. To put it into perspective, the IRP anticipated 510,410 MWh increase in large customer load between 2019 and 2023.

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[9] Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, April 9, 2021, by Dr. Bradley Borum, Director of Research, Policy and Planning on behalf of the Indiana Utility Regulatory Commission, Page 21

[10] Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, April 9, 2021, by Dr. Bradley Borum, Director of Research, Policy and Planning on behalf of the Indiana Utility Regulatory Commission, Page 32

[redacted]

The second concern emphasized by the Director was found on page 21 of the Director's draft report; ". . . the Director would have appreciated one optimization run with a minimum of constraints or exogenous choices pre-selected. The Director recognizes the resulting portfolio might be unrealistic because it fails to adequately account for real world limitations but thinks such an exercise is still informative."[11] CenterPoint Indiana South described the limited number of constraints in section 7.2.4 Additional Modeling Considerations on pages 213~~1~~-214~~2~~ of Petitioner's Exhibit No. 5, Attachment MAR-1. I will describe the three most significant constraints utilized and the reasoning around each one. Ultimately, constraints help produce a portfolio that is practical, achievable, and in-line with the stated objectives of the IRP, including diversity and avoidance of risk. First, as stated on page 213~~1~~ of Petitioner's Exhibit No. 5, Attachment MAR-1:

> [CenterPoint Indiana South] received approval in 2019 from the Commission to upgrade F.B. Culley 3, [CenterPoint Indiana South'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. [CenterPoint Indiana South] 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.

Second, CenterPoint Indiana South included a few constraints around renewable resources. CenterPoint Indiana South conducted an All-Source RFP to obtain renewable pricing per previous Commission guidance and received bids for solar and wind resources. CenterPoint Indiana South limited the amount of these resources that could be selected within modeling based on a few considerations. CenterPoint Indiana South did not allow for more of these resources than available projects from the All-Source RFP. Competition

[11] Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, April 9, 2021, by Dr. Bradley Borum, Director of Research, Policy and Planning on behalf of the Indiana Utility Regulatory Commission, Page 21

for resources is high, and many of the bids that came in were very early in development and speculative. CenterPoint Indiana South did not intend to do self builds for these resources, so it would be impractical to allow the model to select more solar and wind than the market would bear in the early years. Additionally, CenterPoint Indiana South limited the amount of solar resources that could be selected through 2024 to 1,150 MWs (roughly the amount of CenterPoint Indiana South's peak load in the summer). As described on page 250~~48~~ of Petitioner's Exhibit No. 5, Attachment MAR-1:

> 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 [through 2024] was also limited by practical considerations around logistics and operational feasibility.

Third, CenterPoint Indiana South included a constraint that was described on pages 99~~7~~-~~98~~ 100 of the Petitioner's Exhibit No. 5, Attachment MAR-1.

> Market transactions offer supply flexibility but also exposure to potential market risk to [CenterPoint Indiana 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 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 CenterPoint Indiana South did not fully consider energy or capacity purchases.

Modeling is simply a tool to aide in the decision-making process. While an unconstrained model run may provide some information that is useful for the analysis, it will not provide the answer to the IRP analysis. The constraints utilized within the IRP helped produce a wide range of potentially viable portfolios for use within the analysis. Had these constraints not been put into place, the resulting portfolio would have been screened out before probability modeling. Optimization modeling is time consuming and expensive. Reasonable constraints help make the analysis more efficient. Nevertheless, CenterPoint Indiana South has agreed to an unconstrained modeling run in the next IRP.

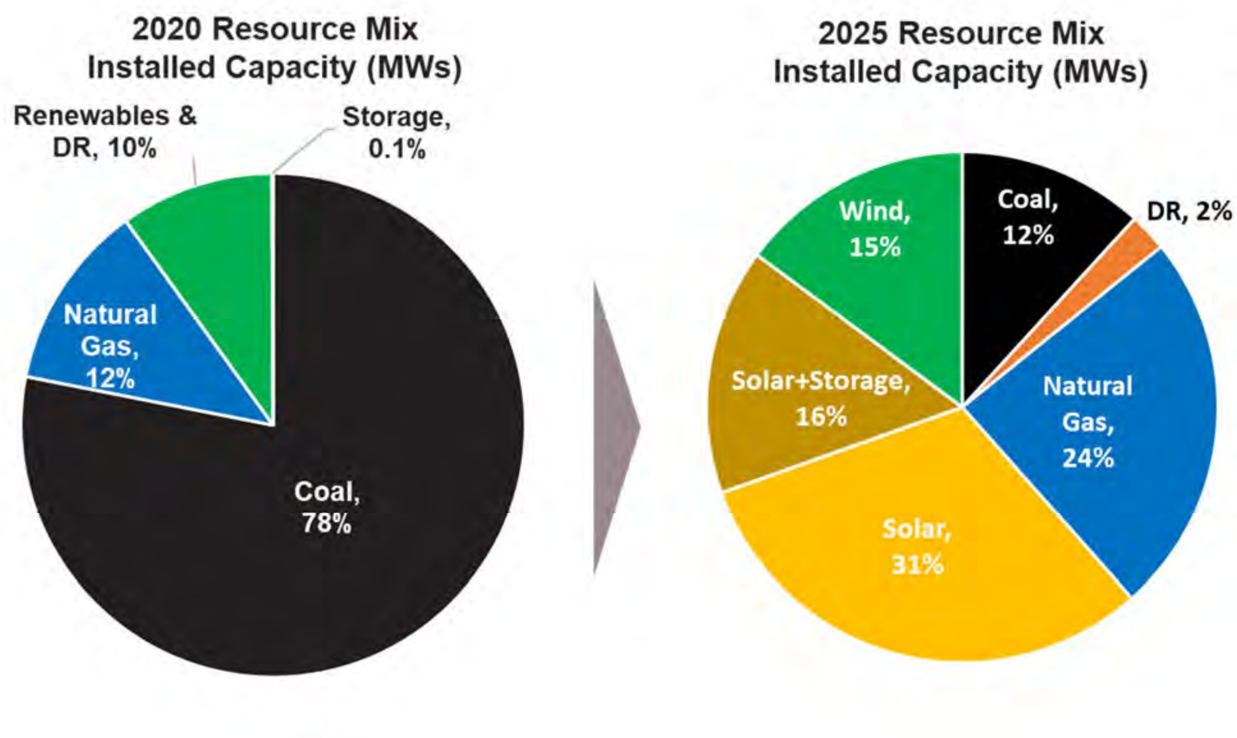
IV. THE PREFERRED PORTFOLIO

Q. What are the major components of the Preferred Portfolio?

A. The Preferred Portfolio is very diversified, with significant amounts of solar, solar plus storage, wind, gas, coal, demand response, and energy efficiency. Specifically, it includes energy efficiency at 1.25 percent between 2021-2023 and 0.75 percent[12] thereafter. The portfolio calls for 300 MW of wind resources to come online in 2022. It also calls for 1,150 MWs of new solar and solar plus storage in 2023-2024 to replace coal capacity, including Warrick Unit #4 which Petitioner jointly operates with Alcoa. Additionally, two CTs come online in 2024-2025. In 2039, 50 MW of storage was selected. The illustration below in Figure 5 shows the Preferred Portfolio's mix of installed capacity.

[12] The level of EE for 2024 and beyond will be decided with future IRPs and DSM filings.

Figure 5: Preferred Portfolio Resource Mix



Q. What are the primary benefits of the Preferred Portfolio?

A. The Preferred Portfolio includes a diverse mix of resources. The risk analysis demonstrated that a diversified mix of generation resources minimizes risk to customers if the future differs from the Reference Case scenario. As described in the final stakeholder meeting on June 15, 2020, and the 2019/2020 IRP, the Preferred Portfolio has the following characteristics: reliability, cost effectiveness, flexibility, diversity, risk mitigation, sustainability, and timeliness.

Q. Why did the Preferred Portfolio rank the best in the risk analysis?

A. Benefits of the Preferred Portfolio are spelled out in detail in Section 9 of the IRP (Petitioner's Exhibit No. 5, Attachment MAR-1) and include affordability, cost uncertainty risk mitigation, environmental risk mitigation, market risk mitigation, future flexibility, reliability, operational flexibility, resource diversity, local resources, and economic development for the CenterPoint Indiana South territory and the state of Indiana. As I mentioned earlier, the Preferred Portfolio performed well across multiple risk factors in the balanced scorecard. It avoids long-term reliance on the capacity market or heavy reliance on emerging technology. The fast start and ramping capability of CTs allows for high penetration of low-cost renewable energy resources, which were consistently selected for all portfolios, regardless of potential future events. It also allows CenterPoint Indiana South to incrementally pursue renewable build out with confidence that dispatchable resources will be available when needed, particularly in winter months where multi-day periods of cloud cover and no wind are possible.

Q. What factors support replacing the generation provided by F.B. Culley 2, Warrick Unit #4, and A.B. Brown units 1 & 2?

A. As described in Petitioner's Witness Wayne D. Games' testimony, F.B. Culley 2 is CenterPoint Indiana South's smallest and least efficient coal unit. It does not compete economically in the MISO market and needs costly upgrades to continue operation many years beyond 2023. Even the Indiana Coal Council ("ICC") acknowledged in their recent comments on CenterPoint Indiana South's 2019/2020 IRP, "There is no dispute over whether it should be retired. . . ."[13] Also, CenterPoint Indiana South's contract with Warrick Unit #4 expires on December 31, 2023, and IRP modeling found extension of the contract was not economical. These two units currently provide 240 MW of installed capacity, 206 MW of which counts towards MISO's planning reserve margin ("PRM") requirement for the 2020 – 2021 planning year. While the Petitioner might be able to find economical ways to keep these units running for a year or two longer to help meet its capacity needs, long-term reliance on these units is not the most economical answer for customers.

As described in Petitioner's Exhibit No. 5, Attachment MAR-1 on page 164~~2~~ of the IRP, A.B. Brown units 1 & 2 utilize dual alkali scrubbers, which present several operational challenges, including: high variable production costs relative to industry standard limestone-based scrubbers, high maintenance costs due to the corrosive dual-alkali process, and challenges in obtaining support and replacement parts for these last of their kind scrubbers. These two units currently provide 500 MW of installed capacity, 466.1 MW of Unforced Capacity ("UCAP") which counts towards MISO's PRM requirement for the 2020 – 2021 planning year.

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[13] ICC comments on CenterPoint Indiana South's 2019/2020 IRP submitted to Director Dr. Bradley Borum on October 28, 2020, bottom of page 6.

Q. What short-term steps does the Preferred Portfolio require CenterPoint Indiana South to take?

A. The Preferred Portfolio calls for CenterPoint Indiana South to pursue renewable projects within the next three years based on the retirement of F.B. Culley 2 and for the expiration of the contract for joint operation of Warrick Unit #4 in December 2023. Adding renewable projects during this time frame has the added benefit of allowing CenterPoint Indiana South customers to take advantage of renewable tax incentives before they expire. Additionally, the plan calls for two combustion turbines equaling approximately 460 MWs of dispatchable installed capacity to replace A.B. Brown units 1 & 2, along with additional renewable wind and solar resources. The Preferred Portfolio also called for capacity purchases to help meet the planning reserve margin requirement during the time in which A.B. Brown units 1 & 2 are retired and the combustion turbines come online.

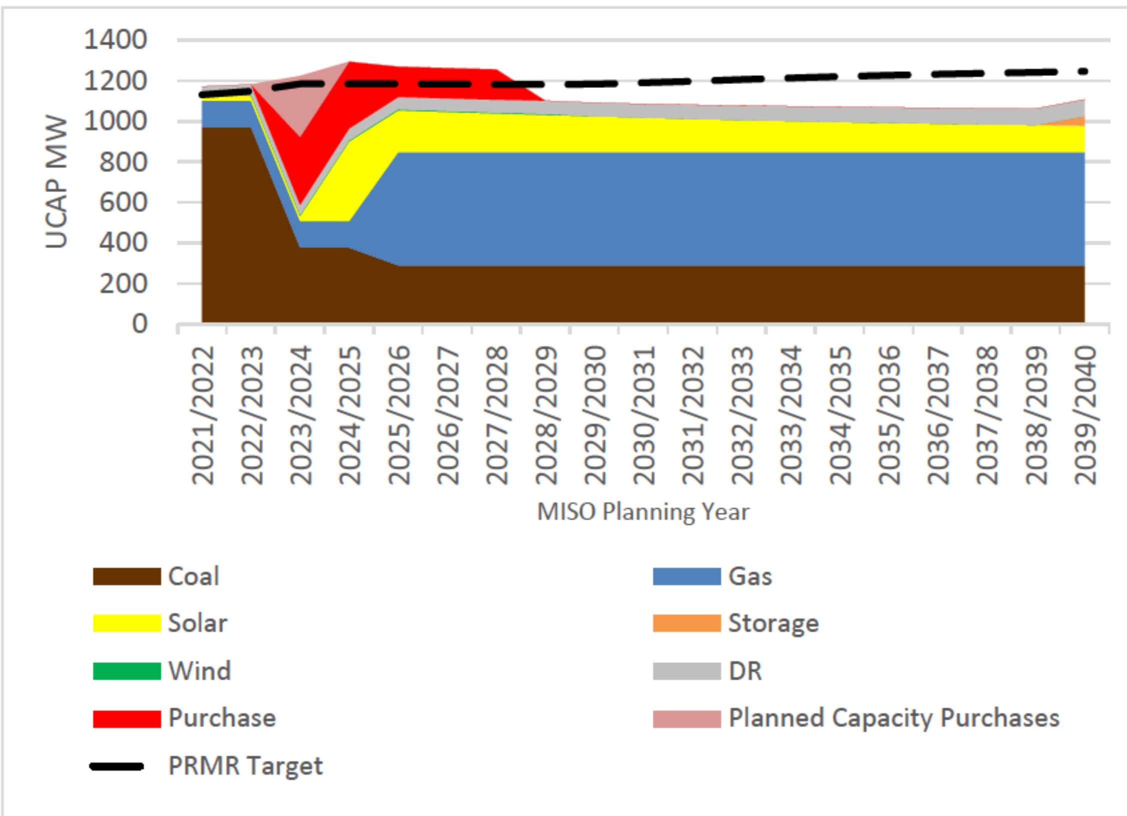
Q. Has CenterPoint Indiana South taken steps to begin implementing the Preferred Portfolio?

A. Yes. Consistent with the short-term action plan in the 2019/2020 IRP, CenterPoint Indiana South selected two projects from the All-Source RFP conducted on June 12, 2019 and filed for these projects in Cause No. 45501. The Posey County Solar Project and Warrick County Solar Project (collectively, the "45501 Solar Projects") were selected. Definitive agreements have been signed for the projects. Additionally, as discussed in Petitioner's Witness F. Shane Bradford's testimony, CenterPoint Indiana South, has begun securing needed capacity through bilateral contracts to ensure CenterPoint Indiana South maintains its PRM requirement while the combustion turbines are constructed. Contingent on approval in this proceeding, CenterPoint Indiana South conducted an RFP for the construction of the CTs and has negotiated a contract to provide firm gas service to the A.B. Brown site to supply the CTs. Finally, CenterPoint Indiana South is in the final stages of evaluating results of a second RFP to secure additional renewable resources identified in the Preferred Portfolio.

Q. Does the Preferred Portfolio offer future flexibility should the future turn out differently than expected?

A. Yes. While the Preferred Portfolio performed consistently well across a wide range of futures, flexibility to pivot is built into the plan. While modeling selected 1,150 MWs of solar and solar plus storage, CenterPoint Indiana South is initially pursuing ~700-800 MWs of a mix of solar ownership and PPAs of varying term lengths from 15-25 years while CenterPoint Indiana South evaluates MISO's future for resource accreditation. Additionally, the Preferred Portfolio included F.B. Culley 3 coal unit through 2039; as Witness Retherford explains, due to a change in regulations, Petitioner is presently evaluating the potential to retire this unit sooner. As described in Witness Bradford's testimony, CenterPoint Indiana South has made capacity purchases to enable the generation transition plan. At the end of these purchases in the 2027/2028 planning year, there is expected to be an additional need that could be filled with additional PPAs, DR, or owned resources. The capacity purchases are illustrated below in Figure 6: Generation Transition Plan.

Figure 6: Generation Transition Plan[14]



[14] Includes Culley 3 through 2039; existing coal, gas, DR and solar resources; 735 MWs of new installed solar capacity, 300 MWs of installed wind capacity, and new 460 MWs of gas CTs. Amount may vary as negotiations continue for resources. Also includes ELCC expectations from the IRP. As more solar penetrates the MISO market, the capacity accreditation is expected to decline.

Finally, the resources included in the Preferred Portfolio are flexible. For instance, should battery prices come down or it make sense to add a large battery to one of our solar fields, this is possible. Also, CenterPoint Indiana South selected GE F-class turbines for the two new combustion turbines. As discussed in Witness Games' testimony, these units can currently burn 30% hydrogen from renewable energy with modifications, thereby lowering the small amount of CO_2 that is expected to be produced from these capacity resources. CenterPoint Indiana South's diverse portfolio is well positioned for the future.

V. COMBUSTION TURBINES PROJECT

Q. Please briefly describe the Combustion Turbines Project.

A. As described in Witness Games' testimony, CenterPoint Indiana South selected F Class CTs through a competitive procurement process. This class of turbines have been in the market for over 30 years and have a proven history of solid and reliable performance. The units are capable of starting in as little as 10 minutes and can ramp 40 MWs per minute, per unit, or 80 MWs per minute. CTs are low cost capacity resources identified in the Preferred Portfolio, supporting intermittent renewable resources in a diverse portfolio.

Q. Have you reviewed the IURC's Statewide Analysis of Future Resources for Electricity ("Statewide Analysis")?

A. Yes. I understand the Statewide Analysis is ongoing and that the most current written version of that analysis is dated 2018. A copy is attached as Petitioner's Exhibit No. 5, Attachment MAR-16.

Q. In your opinion, is the Combustion Turbine Project for which a CPCN is being sought in this proceeding consistent with the Statewide Analysis?

A. Yes. That Analysis cautions that it is not to be construed as an energy plan and it does not predetermine resource decisions. In general, it provides information to various stakeholders. Our proposed Combustion Turbine Project is consistent with the Statewide Analysis, although the data and analysis underlying our proposal has continued to develop since the written Statewide Analysis was completed.

Q. In your opinion, is the Combustion Turbine Project consistent with CenterPoint Indiana South's 2019/2020 IRP?

A. Yes. Two combustion turbines were identified in the Preferred Portfolio to provide low cost capacity to support the low-cost renewable energy resources and help replace 730 MWs of coal generation. The CTs are part of a balanced mix of renewables, gas, coal, and Demand Side Management ("DSM") resources to serve customers, identified in the 2019/2020 IRP.

Q. Does the Combustion Turbines Project fulfill a capacity need identified in CenterPoint Indiana South's 2019/2020 IRP?

A. Yes. The Combustion Turbines Project directly replaces approximately 460 MWs of dispatchable capacity that results from closing A.B. Brown units 1 & 2, which was identified in CenterPoint Indiana South's 2019/2020 IRP. As Petitioner's Witness Retherford describes in her testimony, it is not feasible to continue running A.B. Brown units 1 & 2 until the 2025/2026 planning year (period of time needed to construct the CTs).

Q. What are the benefits of adding combustion turbines generally?

A. The combustion turbines provide several benefits to the Preferred Portfolio. First, they are a part of a diverse mix of resources, which helps to shield customers from risk. Second, combustion turbines compliment renewable resources by providing quick start and fast ramping capability, which is a dramatic improvement over existing coal generation. These attributes, along with the ability to load follow on partially cloudy days supports the build out of solar generation. As solar resources continue to increase in the MISO market, the net peak hour is expected to shift into the evening hours. If needed, CTs may be called upon to help meet this demand as the sun falls behind the horizon; the ability to ramp quickly is important to address the duck curve.[15] Third, combustion turbines provide resilience to the Preferred Portfolio. Dispatchable capacity is needed for long durations when the sun is not shining and the wind is not blowing, particularly in the winter. MISO recently reiterated that the capacity market is moving to a seasonal construct where various resources will receive varying capacity accreditation, depending on the season.

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[15] The duck curve is the graphic representation of solar penetration which pushes the net peak load into mid/late evening. Quick ramping resources are needed to meet this phenomenon.

Gas turbines with firm gas service are expected to have a higher accreditation in the winter at ~95%, while solar is expected to receive approximately 5%.[16] CenterPoint Indiana South's Preferred Portfolio will retain enough dispatchable capacity to meet its expected winter load. During the summer, when load increases, capacity accreditation is expected to slightly decrease for gas and increase for solar.

Fourth, the combustion turbines are a physical hedge on the capacity and energy markets. When volatility occurs with high energy prices, CTs are available to shield customers from high cost. Other top portfolios had a long-term reliance on the capacity market, which is risky for CenterPoint Indiana South customers. In addition to being called upon when market energy prices are high, they are also available to be called upon for reliability issues; however, IRP modeling suggests that these units will not run much, which keeps CO_2 output very low. Finally, CTs provide for future flexibility to burn hydrogen in the long-term. As mentioned by Witness Games, the GE units CenterPoint Indiana South selected have the ability to burn 30% hydrogen today with modifications.

Q. Does CenterPoint Indiana South also need to move to a balanced mix of resources in its portfolio in general?

A. In my opinion, yes. CenterPoint Indiana South believes there is value in a balanced portfolio to reduce risk by having a diverse set of resources available to serve customer load (including not only diversity in generation resources but also DSM). The benefits of a balanced energy mix cannot be overstated. One of the simplest and best ways to plan in an uncertain environment is to provide a diverse portfolio, which provides a hedge against unforeseen changes in regulations, technologies, and market.

Q. Did CenterPoint Indiana South consider DSM as a resource in its 2019/2020 IRP?

A. Yes. CenterPoint Indiana South considered DSM as a resource in its 2019/2020 IRP and included DSM in the Preferred Portfolio. CenterPoint Indiana South considers DSM to be part of a balanced utility resource plan.

[16] MISO, RAN Reliability Requirements + Sub-annual Constructs presentation, RASC, February 3, 2021-updated February 25, 2021, page 22.

Q. In your opinion, are DSM initiatives a viable alternative to completing the CTs identified in the Preferred Portfolio?

A. No. The 2019/2020 IRP demonstrates that DSM will be an important part of CenterPoint Indiana South's resource options in the future. However, the IRP also recognizes that the addition of renewable and gas resources is necessary to meet the needs of the system in the future and to diversify Petitioner's generation portfolio. DSM initiatives may prove to be a viable alternative to future capacity needs. The Preferred Portfolio shows a need for further capacity to meet the forecasted PRM after our short-term actions are complete, and that need would be more if the decision is made to retire F.B. Culley Unit 3 sooner, as being explained by Witness Retherford.

Q. In your opinion, is the addition of the CT Project to CenterPoint Indiana South's generation portfolio in the public convenience and necessity?

A. Yes. The CT Project is consistent with CenterPoint Indiana South's 2019/2020 IRP and is an economic choice to help meet CenterPoint Indiana South's retail electric load 24 hours a day, 365 days a year. The expected capacity attributable to the CT Project is necessary to meet CenterPoint Indiana South's load and adequate reserve margins, particularly in the winter. In addition to providing necessary capacity, the CT Project is a reasonable addition to a portfolio of capacity resources that in the aggregate serve to mitigate risk through diversification. Commission approval of the CT Project and associated relief sought herein is in the public interest and will enhance or maintain the reliability and efficiency of service provided by CenterPoint Indiana South.

Q. Please describe some of the key quantitative and qualitative considerations as to why continuing to run A.B. Brown or converting A.B. Brown is not a good option relative to building two new combustion turbines.

A. As described in the final IRP stakeholder meeting on June 15, 2020, these options are less affordable to customers due to high O&M and on-going capital expenditures to keep the units running. This was evident in the long-term NPVRR for these portfolios as well as near term bill impacts (discussed further below). The NPVRR of converting both A.B. Brown units to gas was $2,784~~2,836~~ million, and the NPVRR of running both A.B. Brown units until 2029 was $2,689~~91~~ million, which was $193~~244~~ million to $98~~9~~ million more than replacing the A.B. Brown coal units with two natural gas CTs.

Operationally, these options have a worse heat rate than new combustion turbines, which drives the need to burn more fuel. The heat rate of gas conversion is approximately 11,000 BTU/kwh, and the heat rate for continuing to run A.B. Brown through 2029 is approximately 10,600 BTU/kwh. Both are less efficient than CTs at approximately 9,900 BTU/kwh.

Additionally, there is less operational flexibility when market prices spike suddenly; converted gas units or coal units cannot start and warm up quickly enough to shield customers from potential high costs. As discussed in Witness Games' testimony slow start times (16-24 hrs.) and slow ramp rates (2-6 MW/Min), which does not position us well to support high penetrations of solar that is expected in and around our service territory, regardless of who owns and operates solar plants. The conversion of the A.B. Brown units locks in our inability to respond quickly when needed. As described by Witness Bradford, MISO's recent market reforms and products pay a premium for resources that can be called upon quickly. He also notes that MISO's Independent Market Monitor recently described the need for significant ramping capability to support solar resources. Witness Games noted that coal units are not made to ramp up and down quickly, and this tends to drive more costs as such causes equipment to wear out more quickly than if the units were able to run as designed (base load units). The CTs on the other hand start within 10 minutes and together have the collective ability to ramp 80 MWs per minute.

Finally, this equipment is old and more prone to break down than new combustion turbines. This is partially why on-going O&M capital spend is necessary, but as Witness Games testifies to the A.B. Brown units have corrosion issues due to chemicals needed to run outdated environmental equipment. When these failures occur, they can have an impact on MISO accreditation.

Q. Why is the Preferred Portfolio with two combustion turbines a better option for customers than the Reference Case, which only has one combustion turbine.

A. Two highly dispatchable combustion turbines allow for a high penetration of renewable resources, ensuring reliability and better hedges against the energy and capacity markets. For example, as described in Witness Bradford's testimony, when there is an unexpected constraint on the transmission system, LMPs can spike to high levels. The CTs will have the ability to turn on quickly and shield CenterPoint Indiana South customers from price volatility.

With two combustion turbines, CenterPoint Indiana South has enough dispatchable resources to meet the winter peak. This is important, as MISO continues to move towards a seasonal capacity construct. Solar resources are expected to receive only 5% of their installed capacity using this MISO planning assumption; of the first 735 MWs of solar installed capacity that CenterPoint Indiana South is pursuing, approximately 37 MWs would count towards the anticipated winter planning reserve margin requirement. It is possible that solar could receive zero accreditation in the winter.

Two CTs will help to better ensure reliability when there are multiday periods of cloud cover and no wind. CTs provide affordable capacity and are available to run for long durations when needed. Conversely, energy storage options are higher priced capacity resources than CTs, and they only typically provide enough power for a 4-hour duration. To provide 8 hours' worth of power, the cost nearly doubles. Additionally, Witness Bacalao describes how widespread adoption of storage is expected to decrease storage capacity accreditation in MISO. This risk factor was not considered in the IRP.

Two CTs provide double the ramping capability than one does to better support intermittent solar locally and on the MISO system to meet the evening net peak. Two CTs are able to start within 10 minutes and can ramp at 80 MW/minute versus 40 MW/minute with one CT. They are also load following.

Q. The Renewables Plus Flexible Gas waits to build the second CT in the mid 2030's. Is there an advantage to building two now?

A. Yes. In addition to the benefits mentioned above, there are construction efficiencies in building the units at the same time. As shown in Technical Appendix Attachment 1.2 Vectren Technology Assessment Summary table from Petitioner's Exhibit No. 5, Attachment MAR-2, the second CT is estimated to be approximately $50 million less capital spend than the second CT when built at the same time. Additionally, building two CTs at the same time keeps existing interconnection rights at A.B. Brown, which shields customers from potential transmission upgrade costs in the future should CenterPoint Indiana South have to re-enter the MISO Queue (a two and a half to three-year process).

VI. 21st CENTURY ENERGY POLICY DEVELOPMENT TASK FORCE PILLARS

Q. Have you reviewed the Final Report issued by the 21st Century Energy Policy Development Task Force dated November 19, 2020 (the "Final Report")?

A. Yes. I reviewed the five pillars that the Task Force recommended serve as a lens through which it would review future potential policy decisions.

Q. What are the five pillars?

A. The five pillars are reliability, resilience, stability, affordability, and environmental sustainability. Reliability consists of two fundamental concepts – adequacy and operating reliability. Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components. Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components.

Q. In your opinion, is the proposal in this proceeding consistent with those five pillars?

A. Yes. The combustion turbines support the addition of clean renewable energy. This is consistent with the environmental sustainability pillar set forth in the Final Report. The total CO_2 output of the combustion turbines is minimal as these units are there for backup and not expected to run much. Moreover, as further supported by the IRP, this project promotes reliability. The Preferred Portfolio provides adequate, dispatchable capacity to meet MISO's planning reserve margin requirements in the summer and the winter in anticipation of a seasonal capacity requirement. The CTs can also supply power and energy requirements when called on by MISO for reliability or when market prices are sufficiently high, shielding customers from price risk. As Petitioner's Witness Games notes, CenterPoint Indiana South proposes to pair renewable generation with quick start and fast ramping dispatchable natural gas CT generation, which will further enhance the ability of the system to withstand sudden disturbances.

Q. In your opinion, is the Preferred Portfolio resilient and stable?

A. Yes. As to resiliency, the Preferred Portfolio helps to minimize the risk of sustained disruption. As further discussed by Petitioner's Witness Bacalao the IRP resulted in a Preferred Portfolio that significantly, but prudently, diversifies the resource mix for CenterPoint Indiana South's generation portfolio to meet current and future load and reserve margin requirements. Reliability was an important consideration of selecting a holistic portfolio. Solar, wind, natural gas combustion turbine, and coal resources are proven technologies that will help ensure CenterPoint Indiana South can continue to meet PRM requirements. Solar assets are also well suited to provide a stable source of energy in the summer when usage is at its highest. This is balanced with sufficient dispatchable resources to meet winter load. The new combustion turbines will include firm gas service to help ensure adequate gas supply in the winter.

Q. Do you believe the Preferred Portfolio will result in an affordable generation mix?

A. Yes. As demonstrated in the IRP, the Preferred Portfolio was among the most affordable options for customers, regardless of the future we face. As shown in Figure 8-2 on page 2464 of the Petitioner's Exhibit No. 5, Attachment MAR-1, also shown below in Table 5, pricing for the Preferred Portfolio was within approximately 1-2% of the Reference Case portfolio in scenarios with varying levels of CO_2 cost, gas costs, coal costs, load, etc. The price of other portfolios evaluated in this analysis swing more depending on the future state. For example, the All Renewables by 2030 or the BAU portfolios are less stable. As discussed later in my testimony, the Preferred Portfolio also minimizes bill impacts in the near term compared to continuing to run the A.B. Brown units through 2029 or conversion to natural gas.

Table 5: Portfolio NPVRR (million $)[17]

	Scenarios				
	Reference	Low Regulation	High Technology	80% Reduction of CO_2 by 2050	High Regulatory
Reference Case	100.0%	100.0%	100.0%	100.0%	100.0%

[17] Conversion portfolios (Bridge ABB1 Conversion + CCGT, Bridge ABB1 Conversion, and Bridge ABB1 + ABB2 Conversion) were updated. Updates are included in the table.

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	110.6%~~112.6%~~	110.7%~~112.6%~~	109.6%~~111.5%~~	109.1%~~111.2%~~	106.0%~~107.4%~~
ABB1 Conversion	102.2%~~103.9%~~	102.9%~~104.5%~~	102.8%~~104.5%~~	102.1%~~103.9%~~	100.8%~~102.0%~~
ABB1 + ABB2 Conversions	108.1%~~110.0%~~	108.1%~~110.0%~~	108.2%~~110.1%~~	107.8%~~109.9%~~	104.1%~~105.5%~~
Diverse Small CCGT	105.3%	105.3%	104.2%	103.5%	102.7%
Renewables + Flex ble 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%

Q. Is the Preferred Portfolio environmentally sustainable?

A. Yes. The Preferred Portfolio 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. Additionally, the Preferred Portfolio 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.

Q. Is the Preferred Portfolio reliable?

A. Yes. CenterPoint Indiana South's balanced portfolio includes a diverse mix of resources with enough dispatchable generation to meet peak demand in the early evening hours during the summer, when the sun goes down, and during winter peak conditions. These resources include F.B. Culley 3 coal, A.B. Brown 3 & 4 gas peaking units, and two new highly dispatchable gas turbines with firm gas service. These units provide fast start (10 minute) and fast ramping capability (40 MW/minute each CT or 80 MW/minute for both CTs), which compliments renewable resources when needed. A reliability assessment was performed as part of the Preferred Portfolio, discussed on pages 197~~5~~-198~~6~~ of Petitioner's Exhibit No. 5, Attachment MAR-1. CTs provide sufficient reactive power reserves[18] to minimize potential voltage issues. Finally, CenterPoint Indiana South's transmission system has 750 MWs of import capability, which allows CenterPoint Indiana South to utilize the system to provide power when market prices are low.

[18] Real power accomplishes useful work while reactive power supports the voltage that must be controlled for system reliability.

VII. COST ISSUES

Q. Do the cost estimates for the combustion turbines align with the IRP cost estimates?

A. Yes. The capital costs and expected O&M costs in this filing align with the previous IRP estimates. The following provides more detail.

Q. How do the cost assumptions associated with the combustion turbines modeled in the IRP compare with the cost of the +/- 10% cost estimates described in Witness Games' testimony?

A. The cost estimate for the two CTs in the IRP was approximately $327.8 million in 2024 dollars, which is higher than the cost of two CTs requested in this case at $323 million, as described in Wayne Games' testimony.

Q. Did you model the cost of firm gas service within the IRP?

A. Yes, as described by Witness Paula J. Grizzle, the estimate for firm gas service is approximately $27.3 million per year in 2024 dollars. This was lower than the amount included in IRP modeling at $28.6 million per year in 2024 dollars.

Q. How does the O&M estimate compare to the IRP?

A. IRP O&M estimates were utilized from the Burns and McDonnell Technology Assessment found in IRP Volume 2 attached as Petitioner's Exhibit No. 5, Attachment MAR-1. O&M projections vary by how much the unit is started and operated. Utilizing a comparable amount of starts and run time[19], O&M estimates in Witness Games' testimony are lower than what was modeled within the IRP. For the purposes of rate impact estimates, discussed below, IRP O&M assumptions were utilized.

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[19] Conservatively assumes 150 starts per year, per unit with a 10% annual capacity factor. The IRP Reference Case capacity factor was approximately 2% over the forecast period.

VIII. RATE ISSUES

Q. Have you estimated the potential bill impact of the combustion turbines?

A. Yes, I provide day one bill impact estimates for the combustion turbines compared to possible alternatives such as conversion of A.B. Brown units 1 & 2 to natural gas or running the A.B. Brown units with coal through 2029. Additionally, I provide an estimate for the total day one bill impact for the generation transition.

Q. When will CenterPoint Indiana South begin recovery of the two combustion turbines?

A. Recovery would begin following a decision in the next general rate case, which is required by the end of 2023.

Q. Please describe Petitioner's Exhibit No. 5, Attachments MAR-3 through MAR-15.

A. Petitioner's Exhibit No. 5, **Attachment MAR-3**, Low End Estimated Net Monthly Rate Impact by Customer Class, is a summary table showing the low end of projected bill impacts based on closing F.B. Culley 2, Warrick Unit #4, A.B. Brown 1 & 2 coal units and replacing them with the two CTs proposed in this case, 300 MW Posey Solar, 100 MW Warrick Solar, 335 MWs of solar PPAs, and 200 MWs of owned wind. Additionally, it shows a high-level estimate of the anticipated impact of securitization from the recently enacted Senate Bill 386. The net impact to expected revenue requirements is then allocated by customer class using current Four-Coincident Peak ("4CP") allocations, approved in Cause No. 43354-MCRA 21-S1.

Petitioner's Exhibit No. 5, **Attachment MAR-4**, High End Estimated Net Monthly Rate Impact by Customer Class, includes all projects listed above with the addition of a 130 MW owned solar plant and an additional 150 MWs of wind project. The net impact to expected revenue requirements is then allocated by customer class using current 4CP allocations.

Petitioner's Exhibit No. 5, **Attachment MAR-5**, Low End Estimated Net Monthly Rate Impact by Customer Class – Existing Allocations, shows the net impact by customer class utilizing current 4CP (capacity based) allocations for owned projects and FAC proxy (energy based) allocations for the low end estimate projects listed above in Petitioner's Exhibit No. 5, Attachment MAR-3.

Petitioner's Exhibit No. 5, **Attachment MAR-6**, High End Estimated Net Monthly Rate Impact by Customer Class – Existing Allocations shows the net impact by customer class utilizing current 4CP (capacity based) allocations for owned projects and FAC proxy (energy based) allocations for the high end estimate projects listed above in Petitioner's Exhibit No. 5, Attachment MAR-4.

Confidential Petitioner's Exhibit No. 5, **Attachments MAR-7 (CONFIDENTIAL)** through **MAR-13 (CONFIDENTIAL)** show Project details for each potential resource in the generation transition and the estimated revenue requirement for each.

Petitioner's Exhibit No. 5, **Attachment MAR-14**, BAU 2029 – Continue ABB1 & ABB2 Project, and Petitioner's Exhibit No. 5, **Attachment MAR-15**, Conversion of ABB1 & ABB2 Coal to Gas Project, show the project cost details for these options, including an estimated revenue requirement for these alternatives as a comparison to building 2 CT's.

Q. Please describe the bill impact focusing just on the addition of the combustion turbines without considering any cost reduction offsets.

A. Petitioner's Exhibit No. 5, Attachment MAR-11~~7 (CONFIDENTIAL)~~ shows that the estimated residential year-one bill impact for a residential customer that uses 1,000 kWh per month is approximately $23 per month. This impact focuses simply on adding the two CTs and does not reflect offsets for sales or O&M and fuel savings from exiting the A.B. Brown units one and two.

Q. How does this compare to the bill impact of converting A.B. Brown 1 & 2 to natural gas or continuing to run these units with coal?

A. As described in the IRP, converting one or both A.B. Brown units to natural gas costs customers more in the long run. Conversion also costs customers more on day one. Petitioner's Exhibit No. 5, Attachments MAR-14 and MAR-15 show that the estimated residential year-one bill impact for a residential customer that uses 1,000 kWh per month is approximately $26 per month for conversion and $35 per month for continuing to run with coal through 2029, respectively. This impact for conversion does not reflect offsets for sales or O&M and fuel savings from exiting the A.B. Brown units 1 & 2 in the case of the conversion. In other words, these are the day one impacts that would be comparable to the $23 per month shown in Attachment MAR-11~~7~~.

Q. You testified that all three of the calculations you have discussed so far do not reflect offsets. Please describe the expected day-one bill impact of implementing the full generation transition plan, including the impact of offsets.

A. The generation transition plan includes closing 730 MWs of coal and replacing with 735-865 MWs of solar, 200-350 MWs of wind, and the two combustion turbines proposed in this case. The plan also calls for securitization of the remaining net book value of the A.B. Brown plant at retirement. The day-one bill impact of the plan is expected to be modest for the generation portion of customer rates, ranging from a $4~~16~~ million dollars decrease per year to an increase of $40~~27~~ million dollars per year in the near term and is expected to decrease in the long-term.

Q. Please provide the detail associated with the Bill impact.

A. The tables below show combined savings in millions of dollars for O&M and fuel savings associated with the closure of 730 MWs of coal, removal of A.B. Brown from rate base (securitization), and the sale of Renewable Energy Credit (REC) sales associated with new wind and solar renewable resources to help offset cost to the customer. Impacts are presented in a range based on how successful CenterPoint Indiana South is at procuring renewable resources. The following tables are included in Petitioner's Exhibit No. 5, Attachments MAR-3 and MAR-4.

Table 6: Low End Summary of Generation Transition Impact Annual Savings and Costs in Millions of Dollars[20]

Description	Savings (Millions $)	Cost (Millions $)	Total (Millions $)
Expected O&M and Fuel Savings from C2, W4, ABB 1&2	($143)		
460 MW Combustion Turbine		$79	
300 MW Posey *	($5)	$37	
100 MW Warrick *	($2)	$10	
335 MW Solar PPA *	($6)	$28	

[20] Estimated rate impact includes Culley 2 through 2023.

200 MW Wind *	($5)	$36	
Securitization	($56~~8~~)	$23	
Subtotal	($217~~29~~)	$213	
Net Cost in millions			($4~~16~~)

*REC Sale Savings

Table 7: High End Summary of Generation Transition Impact Annual Savings and Costs in Millions of Dollars[21]

Description	Savings (Millions $)	Cost (Millions $)	Total (Millions $)
Expected O&M and Fuel Savings from C2, W4, ABB 1&2	($143)		
460 MW Combustion Turbine		$79	
300 MW Posey *	($5)	$37	
100 MW Warrick *	($2)	$10	
335 MW Solar PPA *	($6)	$28	
130 MW Solar Owned *	($2)	$18	
200 MW Wind *	($5)	$36	
150 MW Wind *	($4)	$32	
Securitization	($56~~8~~)	$23	
Subtotal	($223~~6~~)	$263~~2~~	
Net Cost in millions			$40~~27~~

*REC Sale Savings

Q. How will these savings be allocated across customer classes?

A. That will depend on the rate case in 2023 and the associated class cost of service study. However, if bill impacts are spread across customer classes utilizing current 4CP allocations, customers would see the following high-level monthly bill impacts.

Table 8: Summary of Generation Transition Low End Impact Monthly Bills by Class[22]

Day-One Monthly Bill Impact	Customers	4CP Allocations	Monthly Bill Impact 4CP
Residential	132,669	41%	($1~~4~~)
Small General Service	10,118	2%	($1~~2~~)
Demand General Service	8,204	28%	($10~~46~~)

[21] Estimated rate impact includes Culley 2 through 2023.
[22] Estimated rate impact includes Culley 2 through 2023.

Off Season Service	742	2%	($~~3~~9)
Large Power	117	26%	($~~3,1~~700)
High Load Factor	2	1%	($~~6,~~1,300)

Table 9: Summary of Generation Transition High End Impact Monthly Bills by Class[23]

Day-One Monthly Bill Impact	Customers	4CP Allocations	Monthly Bill Impact 4CP
Residential	132,669	41%	$10~~7~~
Small General Service	10,118	2%	$6~~4~~
Demand General Service	8,204	28%	$112~~76~~
Off Season Service	742	2%	$96~~5~~
Large Power	117	26%	$7,5~~,1~~00
High Load Factor	2	1%	$14~~0~~,8~~0~~00

Q. Is it possible that these impacts could look different?

A. Yes. We have done preliminary analysis for securitization, reflected in the table above, with high level estimates for securitization costs, including cost of removal for the A.B. Brown plant, which will require a decommissioning study. The cost for securitization could be higher. But the effects of higher decommissioning would be reflected in other portfolios, because as I understand it, those higher decommissioning costs would be reflected in higher depreciation rates if the A.B. Brown units were retained as coal units or converted to gas. Additionally, CenterPoint Indiana South is including costs associated with owned renewable resources through CECA (allocations are capacity based – 4CP) and PPA renewables though the FAC (energy based). Simply utilizing the current allocation methodology though CECA and the FAC, residential and commercial customers would see a larger decrease, while LP customers could see an increase of approximately 0.8~~6~~ cents to 1.4~~2~~ cents per kWh. Finally, I've included an $8 estimate per MWh for REC sales. This is a reasonable estimate, but the REC market could fluctuate up or down in the future. Current practice is to sell RECs on behalf of CenterPoint Indiana South customers. CenterPoint Indiana South could choose to not sell RECs in the future or be utilized in a green energy tariff for customers.

Q. When do you plan to file for securitization for the A.B. Brown Plant?

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[23] Estimated rate impact includes Culley 2 through 2023.

A. We could file as early as first quarter of 2022. In this filing we will seek authority from the Commission to remove the A.B. Brown plant from rate base, along with decommissioning costs, and costs associated with securing a bond when the proceeds from securitization are received. CenterPoint Indiana South will then charge customers for the bond for a set amount of time. The interest rate on the bond will be substantially lower than the weighted average cost of capital in a rate case. Securitization is expected to provide a benefit to all customer classes.

Q. On the subject of costs, is the Company incurring significant costs related to the planning and preparation of this proceeding and request?

A. Yes. As should be well understood, the IRP process has become much more robust over the past several IRPs. The end result is a much better tool to guide resource planning, but it comes at significant cost. And to take the planning from the IRP and further refine for approval of generation is also much more involved than it has been in past years, with the use of outside consultants and studies to explore alternatives.

Q. **How are these costs expected to be recovered?**

A. We are currently carrying these costs on our books and will record them to the cost of owned generating resources, a portion of which will be applied to the new CTs. These costs are included in the estimate of costs of the CTs presented by Witness Games. If for whatever reason the CTs are not ultimately placed in service, we are seeking authority to defer these costs as a regulatory asset at that time to be recovered as described by Witness Kara R. Gostenhofer.

IX. <u>CONCLUSION</u>

Q. Does this conclude your direct testimony?

A. Yes, at the present time.

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a CENTERPOINT ENERGY INDIANA SOUTH
(CENTERPOINT INDIANA SOUTH)

IURC CAUSE NO. 45564

DIRECT TESTIMONY (PUBLIC)
OF
MATTHEW A. RICE
DIRECTOR OF INDIANA ELECTRIC REGULATORY AND RATES

ON

INTEGRATED RESOURCE PLAN, NECESSITY OF THE COMBUSTION TURBINES PROJECT AND RATEMAKING ISSUES

SPONSORING PETITIONER'S EXHIBIT NO. 5 (PUBLIC)

ATTACHMENTS MAR-1 THROUGH MAR-16

DIRECT TESTIMONY OF MATTHEW A. RICE

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Matthew Rice. My business address is 211 NW Riverside Drive, Evansville, Indiana 47708.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting testimony on behalf of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("Petitioner", "CenterPoint Indiana South", or "Company"), which is an indirect subsidiary of CenterPoint Energy, Inc.

Q. What is your role with respect to Petitioner?

A. I am Director of Indiana Electric Regulatory and Rates.

Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Business Administration from the University of Southern Indiana in 1999. I also received a Master of Business Administration from the University of Southern Indiana in 2008.

Q. Please describe your professional experience.

A. Prior to working for CenterPoint Indiana South, I worked as a Market Research Analyst for American General Finance for six years working primarily on customer segmentation, demographic analysis, and site location analysis. In 2007, I joined the Company as a Market Research Analyst, and have held various positions of increasing responsibility, including Senior Analyst, Manager of Market Research, and Director of Research and Energy Technologies. Since 2009, I have been responsible for long-term energy forecasting for the Company's IRPs, helping to manage the Company's 2011, 2014, 2016, and 2019/2020 IRPs. I have also managed its IRP stakeholder process since 2014. My duties have included conducting economic analysis, primary and secondary customer research (including surveying, focus groups, segmentation, and demographic analysis), customer satisfaction research, housing market research, and monitored industry research. In February 2019, I became Manager of Resource Planning with responsibility for internal and external generation analysis and reporting. I was named to my current position of Director of Indiana Electric Regulatory and Rates in October 2020.

Q. What are your present duties and responsibilities as Director of Indiana Electric Regulatory and Rates?

A. I am responsible for Petitioner's electric regulatory and rate matters in regulated proceedings before the Indiana Utility Regulatory Commission ("Commission"). I also have responsibility for resource planning and reporting for CenterPoint Indiana South, including the IRP.

Q. Have you previously testified before the Indiana Utility Regulatory Commission ("IURC" or "Commission")?

A. Yes. I testified before the Commission in support of CenterPoint Indiana South's Certificate of Public Convenience and Necessity ("CPCN") in Cause No. 45052, and Petitioner's request for approval of a tariff rate for Excess Distributed Generation in Cause No. 45378. Additionally, I recently provided written testimony in Cause No. 45501, Cause No. 44910-TDSIC-8, Cause No. 44909-CECA 3, and in Cause No. 45052-ECA 2.

II. <u>PURPOSE & SCOPE OF TESTIMONY</u>

Q. What is the purpose of your testimony in this proceeding?

A. My testimony describes the analysis and results of CenterPoint Indiana South's 2019/2020 Integrated Resource Plan ("2019/2020 IRP") process. I summarize and respond to comments made in the draft Director's report issued on April 12, 2021. In addition, I describe and support CenterPoint Indiana South's request for a CPCN to construct two combustion turbines ("CTs") at the A.B. Brown site to replace A.B. Brown coal units 1 and 2 and testify that the proposed generation is consistent with the IRP. I describe how the cost of the A.B. Brown combustion turbines will be recovered in rates. Finally, I describe how customer rates are projected to be impacted by the Generation Transition Plan.

Q. Are you sponsoring any attachments to your direct testimony in this proceeding?

A. Yes. I am sponsoring the following attachments:

- Petitioner's Exhibit No. 5, **Attachment MAR-1**: CenterPoint Indiana South's 2019/2020 Integrated Resource Plan Volume 1 of 2
- Petitioner's Exhibit No. 5, **Attachment MAR-2 (CONFIDENTIAL)**: CenterPoint Indiana South's 2019/2020 Integrated Resource Plan Volume 2 of 2
- Petitioner's Exhibit No. 5, **Attachment MAR-3**: Low End Estimated Net Monthly Rate Impact by Customer Class
- Petitioner's Exhibit No. 5, **Attachment MAR-4**: High End Estimated Net Monthly Rate Impact by Customer Class
- Petitioner's Exhibit No. 5, **Attachment MAR-5**: Low End Estimated Net Monthly Rate Impact by Customer Class – Existing Allocations
- Petitioner's Exhibit No. 5, **Attachment MAR-6**: High End Estimated Net Monthly Rate Impact by Customer Class – Existing Allocations
- Petitioner's Exhibit No. 5, **Attachment MAR-7 (CONFIDENTIAL)**: Posey County Solar Project
- Petitioner's Exhibit No. 5, **Attachment MAR-8 (CONFIDENTIAL)**: Warrick County Solar Project
- Petitioner's Exhibit No. 5, **Attachment MAR-9 (CONFIDENTIAL)**: 335 MW Solar PPA Projects
- Petitioner's Exhibit No. 5, **Attachment MAR-10 (CONFIDENTIAL)**: 200 MW Wind PPA Project
- Petitioner's Exhibit No. 5, **Attachment MAR-11**: 2 Combustion Turbine Project
- Petitioner's Exhibit No. 5, **Attachment MAR-12 (CONFIDENTIAL)**: 130 MW Owned Solar
- Petitioner's Exhibit No. 5, **Attachment MAR-13 (CONFIDENTIAL)**: 150 MW Wind Project
- Petitioner's Exhibit No. 5, **Attachment MAR-14**: BAU 2029 – Continue ABB1 & ABB2 Project
- Petitioner's Exhibit No. 5, **Attachment MAR-15**: Conversion of ABB1 & ABB2 Coal to Gas Project

Q. Were these attachments prepared by you or under your direction?

A. Yes, they were. The Company's 2019/2020 IRP process was managed under my direction or supervision, although it is important to recognize that other Company employees and consultants with specific areas of expertise engaged by the Company were involved in the process of developing the 2019/2020 IRP. In addition to these attachments, I am also sponsoring Petitioner's Exhibit No. 5, Attachment MAR-16, which was prepared by the Commission and is its 2018 Report of the Statewide Analysis of Future Resources for Electricity.

III. CENTERPOINT INDIANA SOUTH'S 2019/2020 IRP PROCESS

Q. Please describe how CenterPoint Indiana South approached the 2019/2020 IRP.

A. The 2019/2020 IRP was CenterPoint Indiana South's most detailed resource planning analysis process. The Company worked with several industry experts to conduct the technical analysis: Itron provided the long-term energy and demand forecast; 1898 and Company, a Burns and McDonnell company ("Burns and McDonnell"), worked with CenterPoint Indiana South to conduct an All-Source Request For Proposals ("All-Source RFP") and provide modeling inputs for various generating resources; Black and Veatch assisted with several studies utilized to evaluate numerous alternatives for existing resources; GDS provided Energy Efficiency modeling inputs; and Siemens PTI, formerly Pace Global Energy Services ("Siemens PTI"), provided scenario development, deterministic modeling, probabilistic modeling, and provided assistance with the risk analysis. A copy of Petitioner's 2019/2020 IRP is attached to my testimony as Petitioner's Exhibit No. 5, Attachments MAR-1 and MAR-2 (CONFIDENTIAL).

Q. What process did Petitioner use in developing the 2019/2020 IRP?

A. Petitioner began the process by reviewing stakeholder comments from the 2016 IRP, including the Director's Report, and by carefully reviewing the Commission Orders issued in connection with Petitioner's requests for CPCNs in Cause Nos. 45052 (F.B. Culley 3 upgrades and Combined Cycle Gas Turbine ("CCGT")) and 45086 (50 MW Troy solar). This feedback was used to formulate twelve continuous improvement commitments that were shared with CenterPoint Indiana South IRP stakeholders in our first public stakeholder meeting on August 15, 2019, and fulfilled on June 30, 2020, with the submission of the 2019/2020 IRP. In the first stakeholder meeting, CenterPoint Indiana South presented the analysis plan and laid out all topics to be discussed with stakeholders for each of CenterPoint Indiana South's public stakeholder meetings. Figure 3.1 "2019/2020 Stakeholder Meetings" on page 110 of the IRP, Petitioner's Exhibit No. 5, Attachment MAR-1, details the topics discussed in each meeting, summarized in Figure 1 below.

Figure 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

The general process involved presenting information and gathering feedback from stakeholders on key topics, including but not limited to the following: objectives, scorecard development, forecasts, modeling inputs, scenario development, portfolio development, technical modeling, and results. At the beginning of each stakeholder meeting, CenterPoint Indiana South made a point to follow up with stakeholders on input provided in the prior meeting. Often stakeholder feedback was utilized, but in instances where it was not, CenterPoint Indiana South discussed why it was not used. The planning analysis began with an All-Source RFP, which was conducted simultaneously with the IRP and was utilized as an input into modeling for resource selection/portfolio development. Objectives were presented at the first meeting. Scorecard development also began at this meeting and was refined throughout the process based on stakeholder feedback and evaluation of measures to ensure that each was a good representation of the risk factor it represented. Scenarios (potential future states) then were developed with stakeholder input for use in deterministic modeling. Portfolios (combinations of resource options to meet customer load over the evaluation period) were then developed with stakeholder input. Care was taken to ensure a wide range of scenarios and portfolios were utilized and evaluated within the IRP analysis, respectively. These portfolios then were modeled and evaluated within the deterministic futures and within probabilistic simulation of 200 potential futures (also referred to as stochastic modeling). CenterPoint Indiana South utilized quantitative and qualitative information produced within this analysis to select a preferred portfolio.

Q. Please describe the role of the All-Source RFP within the IRP.

A. Per Commission feedback in Cause No. 45052, CenterPoint Indiana South, with the help of Burns and McDonnell, conducted an All-Source RFP to gather resource availability and pricing information for various resources, particularly emerging resources such as solar, solar + storage, and standalone storage. Results of the All Source RFP were summarized into modeling inputs for the IRP for solar, solar + storage, standalone storage, and wind.

Q. What steps did CenterPoint Indiana South take to ensure that pricing included within modeling was as accurate as possible?

A. Care was taken to help ensure up-to-date and accurate information was included within modeling. For example, only projects that provided a firm price and were either on CenterPoint Indiana South's system or included a delivered price were included within modeling inputs. These were referred to as Tier 1 projects within the IRP.

> Proposals were divided into two tiers, based on factors that could add cost risk to [CenterPoint Indiana South] customers. Tier 1 Proposals were those that included binding pricing and delivery of energy to SIGE.SIGW ([CenterPoint Indiana South's] load node) or were physically located in [CenterPoint Indiana South'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 [CenterPoint Indiana South's] system, which increases cost risk due to congestion. Despite these risks, several were still analyzed and considered during the RFP evaluation process; however, [CenterPoint Indiana South] wanted, to the extent possible, to include

> bids with more price certainty within the IRP modeling in order to protect customers from price volatility.

Petitioner's Exhibit No. 5, Attachment MAR-1 at 155.

Burns and McDonnell took care to understand the bids and include all relevant costs, including known transmission upgrades. This involved communications between Burns and McDonnell and bidders to clarify information provided within the bid. Relevant data was provided to Burns and McDonnell via a standardized template to help keep information consistent among bids.

Q. Were bids for traditional fossil fuel resources used to create modeling inputs?

A. No, CenterPoint Indiana South received two bids for 100 MW coal PPAs (5 and 10 years), and several bids for mid-sized to large natural gas CCGTs. None were Tier 1 bids and therefore were not modeled. No bids were received for CTs. For new traditional fossil fuel resources, CenterPoint Indiana South relied on a technology assessment from Burns and McDonnell for cost and operational data, found in IRP Vol. 2, Petitioner's Exhibit No. 5, Attachment MAR-2.

Q. Did you receive any Demand Response bids?

A. Yes, CenterPoint Indiana South received only one bid for a demand response resource. It was for 50 MWs over a 6-year duration and covered the years where there was not a capacity need (2021 – 2022). Capacity was modeled as a potential resource within the IRP. The cost of this bid was higher than the capacity price forecast utilized within the IRP.

Q. Was cogeneration considered?

A. Yes. However, we did not receive any Tier 1 bids for cogeneration, so cogeneration was not an option to be selected in the near term. In the long-term, Combined Heat and Power ("CHP") was considered but not selected.

Q. Did you consider joint ownership of any facilities?

A. Yes, we approached other electric utilities in Indiana about jointly owning generation. No partnership opportunities materialized.

Q. Did you conduct a full Levelized Cost of Energy ("LCOE") screening analysis to

exclude technologies from being modeled?

A. No. In the 2016 IRP, an LCOE screening analysis was necessary because of the use of Strategist modeling software, which could not analyze multiple resources options at one time. The screening analysis removed resources that were not cost effective, prior to modeling to improve efficiency. There was no need to conduct a full LCOE analysis in the 2019/2020 IRP, as the Aurora model was able to consider many options at one time. This was responsive to the Commission's findings in Cause No. 45052 that ". . . multiple less expensive alternatives" were screened out. Only two options were excluded prior to modeling: aeroderivative natural gas combustion turbines due to high-pressure gas supply; and reciprocating natural gas engines due to high cost. In addition to multiple existing unit options (continue coal, retire coal, or conversion), the model was able to consider a large number of new options simultaneously, including: hydroelectric, wind, wind plus storage, solar, solar plus storage, lithium-ion battery storage, flow battery storage, energy efficiency, demand response, coal, biomass, landfill gas, combined heat and power, combined cycle gas, and simple cycle gas.

Q. What forecasts did CenterPoint Indiana South use in its 2019/2020 IRP?

A. Multiple forecasts were used as an input to the analysis to first develop a Reference Case. As described in Petitioner's Exhibit No. 5, Attachment MAR-1 Section 2.4.1 of the IRP, pages 91-93, CenterPoint Indiana South relied on several industry experts for key inputs in the IRP analysis. For coal, gas, market capacity price forecasts, and long-term emerging resource costs, a consensus forecast was used. For natural gas and coal, CenterPoint Indiana South created an average price using data from PIRA Energy Group, Wood Mackenzie, Siemens PTI, ABB, and Energy Ventures Analysis ("EVA"). For the MISO Zone 6 capacity value, CenterPoint Indiana South created an average, utilizing Siemens PTI, ABB, and Wood Mackenzie forecasts.[1] The long-term capital price forecast (beyond 2024) for emerging supply side resources was based on the average of National Renewable Energy Laboratory ("NREL"), Burns and McDonnell, and Siemens PTI forecasts. Siemens PTI developed the carbon price forecast. Itron developed the energy and demand forecast. GDS created a price forecast for demand side resources. Siemens PTI utilized both AURORAxmp power dispatch model with Reference Case inputs and

[1] CenterPoint Indiana South did not have access to a capacity forecast from PIRA or EVA.

expectations for the broader market to generate on-peak and off-peak power prices in the MISO region. To create varying inputs for scenarios, CenterPoint Indiana South worked with stakeholders to determine how key inputs would vary by scenario in the short-, mid-, and long-term based on narrative-based futures. This process helped ensure multiple perspectives were captured and used to create a wide range of potential futures. Siemens PTI used probabilistic distributions and adjusted Reference Case forecasts for each scenario in conjunction with stakeholder guidance, where reasonable.

Q. In your opinion, were the forecasts used by CenterPoint Indiana South reasonable?

A. Yes. Following the 2016 IRP, CenterPoint Indiana South was praised in the Director's report for using consensus forecasts where possible to increase transparency for stakeholders and incorporate multiple views from credible sources. CenterPoint Indiana South continued using consensus forecasts to develop the 2019/2020 IRP. Other inputs provided by expert third-party sources were shared and discussed as part of the stakeholder process. Forecasts were also compared with publicly available forecasts, such as the Energy Information Administration's Annual Energy Outlook, for reasonableness.

Q. Did CenterPoint Indiana South consider stakeholder input received at the Company-specific meetings?

A. Yes. CenterPoint Indiana South held three workshops as part of these meetings designed to solicit input from stakeholders that was incorporated into the IRP planning process. The fourth public meeting included a preview of the Preferred Portfolio. CenterPoint Indiana South described how stakeholder input received at the prior stakeholder meeting was utilized in each meeting. Where feedback was not used, CenterPoint Indiana South explained the reasoning. Feedback from stakeholders helped shape the analysis in significant ways, including but not limited to: scorecard development (identification and inclusion of key risks including considering full life cycle of CO_2e), scenario development, expected MISO accreditation of resources, fuel price forecasts, consideration of a wide range of portfolios, and use of an All-Source RFP.

Q. Did you incorporate stakeholder input into the portfolio development process?

A. Yes. CenterPoint Indiana South incorporated stakeholder input prior to and during the

2019/2020 IRP analysis. Continuous improvement of the resource planning analysis was integral to CenterPoint Indiana South's 2019/2020 IRP. CenterPoint Indiana South learned from the last IRP that stakeholders were interested in utilizing least cost optimization to help ensure portfolio cost was as low as possible. In the third public stakeholder meeting held on December 13, 2019, CenterPoint Indiana South discussed each portfolio development strategy and described the relevant stakeholder input used to help develop portfolios. Examples of stakeholder input considered included, but were not limited to: explore options at A.B. Brown, make adjustments to various scenarios, explore conversion options, run A.B. Brown until 2029, run A.B. Brown until 2039, do not run fossil fuel plants beyond 2030, consider smaller CCGT options, and consider flexible gas CTs and renewables.

Q. How did CenterPoint Indiana South develop the portfolios modeled in the 2019/2020 IRP?

A. CenterPoint Indiana South worked with stakeholders to consider and utilize strategies to develop a wide range of portfolios. Five portfolio development strategies were discussed with stakeholders: (i) Status Quo (i.e., continue running existing units), (ii) Scenario-Based (i.e., least cost optimization), (iii) Bridge (i.e., continued use of A.B. Brown assets), (iv) Diverse (i.e., diverse energy with renewables, gas, and coal), and (v) Renewables Focused (i.e., much less to no reliance on fossil fuel resources). Except for the Scenario-Based portfolio development strategy, various resource options were locked in, and deterministic modeling was utilized to select the most economical way to meet the remaining capacity and energy obligations. For example, under the Bridge portfolio development strategy, the Brown units would continue to run with the existing scrubber through 2029, and the model determined the replacement to meet MISO's planning reserve margin requirements and optimized for lowest net present value of revenue requirements ("NPVRR"). The Scenario-Based portfolio options were created for each of the five deterministic scenarios. In this process, existing coal units[2] were evaluated for economic retirement. Ultimately this process produced fifteen distinct portfolios, ranging

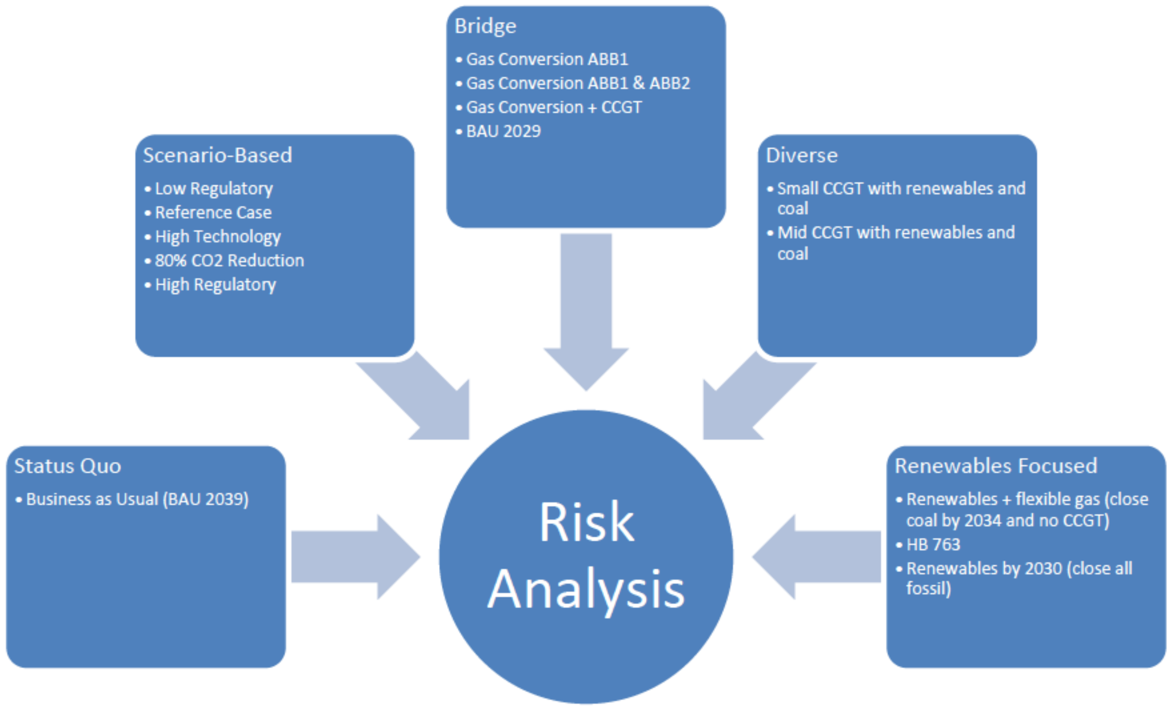
[2] A.B. Brown units 1 & 2, F.B. Culley 2, and Warrick Unit #4. Warrick Unit #4 is a jointly operated plant with Alcoa Power Generating, Inc. ("Alcoa"). The current contract expires at the end of 2023, leaving a 150 MW capacity shortfall currently in all portfolios. CenterPoint Indiana South modeled a potential 3-year extension of the contract; it was not selected based on economics.

from continuing most coal resources through the end of the forecast to an all-renewables portfolio by 2030.

Q. Please summarize the fifteen optimized portfolios that CenterPoint Indiana South examined.

A. Fifteen portfolios were created utilizing the process described above. Figure 2 below is a visual representation of the wide range of portfolios analyzed, bucketed by five portfolio development strategies: Status Quo, Scenario-Based, Bridge, Diverse, and Renewables Focused. A brief description of each strategy follows below. A Status Quo portfolio identified as Business as Usual ("BAU") through 2039 was included as a bookend. This portfolio included continuing to run all coal plants, except for Warrick Unit #4, through 2039. Five Scenario-Based portfolios were created (one per scenario) for the following scenarios: Reference Case, Low Regulatory, High Technology, 80 percent reduction of CO_2 by 2050, and High Regulatory. Each of these potential future states were optimized to produce a least cost portfolio in each future state. Four Bridge portfolios were created to explore options to continue to utilize existing equipment at the A.B. Brown plant. These portfolios included converting one unit to gas, converting two units to gas, converting one unit to gas with the addition of a small CCGT, and continuing to run both units with coal through 2029. Two Diverse energy portfolios were created: one with a small CCGT and the other with a mid-sized CCGT. These portfolios were included to explore options that produce a balanced mix of energy from coal, gas, and renewable resources. Finally, three Renewables Focused portfolios were created. The first was a Renewables Plus Flexible Gas portfolio, which involved closure of all coal units by 2034 and included gas CTs, renewables, and storage. The House Bill 763 portfolio was created with a very high CO_2 price per stakeholder input. The other bookend portfolio was to close all fossil fuel plants by 2030.

Figure 2: Portfolios by Strategy



All portfolios included demand side resources (i.e., Energy Efficiency and Demand Response). It should also be noted that the model selected a significant amount of wind and solar resources in all portfolios (300 MWs of wind and 1,150 MWs of solar before 2025), including the BAU portfolios, in part to replace Warrick Unit #4, but also because these resources lowered the NPVRR due to their production of low cost energy.

Q. Please describe the role of CO_2 in your analysis.

A. One of the biggest risk factors considered in this analysis was CO_2 output. Scenarios, potential future states, were constructed using various regulatory environments including alternate paths for CO_2. The Low Regulatory scenario only included the Affordable Clean Energy (ACE) rule, which required upgrades at coal plants to improve efficiency. The Reference Case assumed ACE would be repealed and replaced with a modest CO_2 tax beginning in 2027. As mentioned in Petitioner's Witness Angila M. Retherford's testimony, ACE has since been vacated in court. The High Technology scenario assumed a low CO_2 tax beginning in 2025. The 80% Reduction of CO_2 by 2050 includes a CO_2 cap and trade price that is consistent with the Paris Accords, designed to achieve an 80% reduction in

CO_2 by 2050 from 2005 levels. Finally, the High Regulatory scenario includes an extremely high CO_2 tax beginning in 2022. Table 1 below shows a visual summary of each scenario.

Table 1: Scenario Summary Table

	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

Additionally, CenterPoint Indiana South worked with Siemens to incorporate a CO_2 equivalent measure for lifetime life cycle emissions for the score card. This measure included cradle to grave emissions for each portfolio, including, but not limited to, emissions associated with building the resource, getting it on site, methane leakage from the well head, emissions out of the stack, and decommissioning. Generation was tracked by resource and was multiplied by a CO_2e factor supplied by NREL. In this way, CO_2e was one trade off considered within the scorecard.

CO_2 prices were also utilized within stochastic modeling. Each portfolio was modeled in 200 potential future states to capture the cost of each portfolio and cost risk. A wide range of CO_2 prices were included in the net present value and the 95th percentile net present value[3] of each portfolio. The higher the CO_2 output for a portfolio, the higher the portfolio cost and cost risk.

Q. What were the CO_2 prices used within scenario modeling?

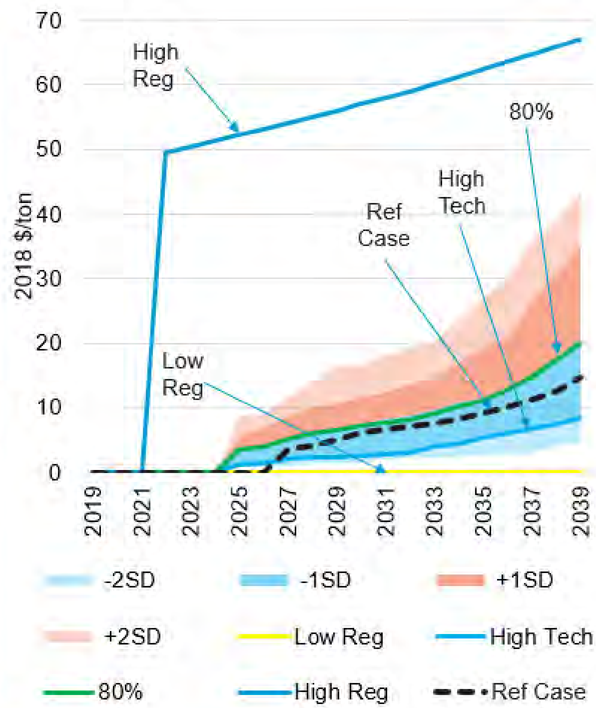
A. CenterPoint Indiana South included a wide range of CO_2 prices within scenario modeling

[3] 95th percentile of NPVRR (million$) across 200 dispatch iterations under varying market conditions. Used to illustrate the upper end cost risk for each portfolio within the IRP scorecard. Simply put, there is a 5% chance costs could go above this level.

to help understand the potential costs of future regulations to customers. The Preferred Portfolio preformed consistently well across multiple potential future states. Figure 3 below shows CO_2 cost modeled within each deterministic scenario.

Figure 3: Scenario CO_2 Costs

	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

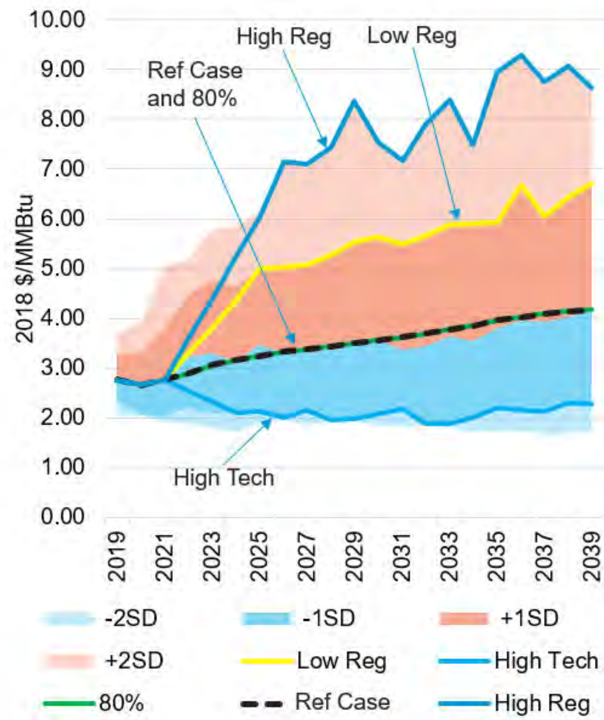


4 **Q. What were the gas prices used within scenario modeling?**

5 A. CenterPoint Indiana South modeled a very wide range of gas prices, including the High Regulatory scenario, which varied gas prices by two standard deviations. This was based on Commission guidance in Cause No. 45052 to fully explore risks of higher gas prices. The High Regulatory scenario assumes a fracking ban that drives supply down and prices dramatically up. Figure 4 below shows the range of gas prices modeled in the 2019/2020 IRP within each deterministic scenario.

Figure 4: Scenario Natural Gas Costs

	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



Q. What analyses did CenterPoint Indiana South use to determine the Preferred Portfolio?

A. CenterPoint Indiana South worked with Siemens PTI to conduct a multi-facetted risk analysis, which included evaluating portfolios on a quantitative and qualitative basis. After creation of the fifteen portfolios, each portfolio was evaluated utilizing simulated dispatch in the Reference Case. Several portfolios included fatal flaws and were excluded from further consideration. As described in more detail in Petitioner's Exhibit No. 5, Attachment MAR-1 Section 8.2 Evaluation of Portfolio Performance, on pages 245-246 of the IRP, these included the HB 763, Low Regulatory, High Regulatory, 80 percent reduction of CO_2, and the Diverse Energy Mid-sized CCGT portfolio. Reasons for the exclusion of these portfolios included high net sales, high market exposure, high cost, or redundancy. The remaining ten portfolios were then dispatched in each deterministic scenario to determine performance among a wide range of potential future states. Some portfolios performed very consistently in terms of cost across each scenario, including the Reference Case, preferred portfolio, and Renewables Plus Flexible Gas. Others, like the BAU portfolio or the all renewables portfolio had much greater cost variation relative to the Reference Case across each potential future. Next, the remaining ten portfolios were dispatched 200 times under varying market conditions. Information gathered from this modeling was then utilized to populate the balanced scorecard, which was developed with stakeholder input. The balanced scorecard included quantitative measures to help CenterPoint Indiana South understand tradeoffs among competing objectives of the IRP; these included stochastic mean 20-year NPVRR (cost), 95th Percentile Value of NPVRR (cost risk), Percent Reduction of CO_2e (life cycle emissions reduction including CO_2, methane and other emissions on a CO_2 equivalent basis), long-term percentage reliance on the energy market for sales or purchases, and long-term percentage reliance on the capacity market for sales and purchases. Table 2 below shows a summary of these measures.

Table 2: Quantitative IRP Scorecard Objectives and Metrics

Objective	Metric
Affordability	Mean value for the 20-Year Net Present Value of Revenue Requirements (NPVRR) (million$) across 200 dispatch iterations under varying market conditions
Cost Uncertainty Risk Minimization	95th percentile of NPVRR (million$) 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 (%) and Annual Capacity Sales and Purchases, divided by Total Resources, average (%)

Six portfolios (five included continued use of A.B. Brown with coal or conversion options and the remaining CCGT option), which were highest in cost and cost risk, were removed from consideration at this point based on their overall performance on scorecard measures and other qualitative considerations discussed at the last stakeholder meeting on June 15, 2020. Four competitive options remained for further analysis and consideration: (i) the Reference Case, (ii) Renewables Plus Flexible Gas, (iii) Renewables by 2030, and (iv) the High Technology portfolio. Table 3 below provides details regarding each portfolio.

Table 3: Portfolio Detail

Year	Reference Case	Renewables + Flexible Gas	Renewables by 2030	High Technology
2021-23	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)
2023	New Solar (731 MW), New Storage (126 MW)	New Solar (731 MW) New Storage (126 MW)	New Solar (731 MW) New Storage (278 MW)	New Solar (731 MW) New Storage (126 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)
2024	New Combustion Turbine (236 MW)	New Combustion Turbine (236 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
2024-26	0.75% Energy Efficiency	0.75% Energy Efficiency	1.00% Energy Efficiency	0.75% Energy Efficiency
2025		-	-	New Combustion Turbine (236 MW)
2027-39	0.75% Energy Efficiency	0.75% 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)	-
2033-39	New Solar (250 MW)	Retire FBC3 (270 MW), New Combustion Turbine (236 MW)	New Solar (450 MW)	New Storage (50 MW)
2024-39	Average Annual Capacity Market Purchases (137 MW)	Average Annual Capacity Market Purchases (135 MW)	Average Annual Capacity Market Purchases (170 MW)	Average Annual Capacity Market Purchases (4 MW)

Q. Within scenario-based optimization was any coal unit selected to continue running based on economics?

A. No. Every scenario retired 730 MWs of coal, including the Low Regulatory Scenario which was favorable to coal resources. As shown in Table 1 above, the Low Regulatory Case included no price for CO_2[4], low coal cost (declining and below $1.80 per MMBTu), higher load than the Reference Case, and higher gas prices than the Reference Case.

Q. What were the results of the scorecard process?

A. Of the four remaining portfolios, the High Technology portfolio performed well across all risk factors. Within the IRP, the cost was listed as being within 2.5 percent of the lowest cost portfolio, the Renewables Plus Flexible Gas. The Renewables Plus Flexible Gas portfolio retires F.B. Culley 3 earlier than the High Technology portfolio thereby saving customers money. Both portfolios include about the same level of renewables and a second CT. As discussed in Petitioner's Witness Nelson Bacalao's testimony, this cost gap closes to 1.5 percent due to construction efficiencies that would be lost with building

[4] Minimal costs were included to comply with ACE, which has since been vacated.

the second CT ten years later under the Renewables Plus Flexible Gas option, which is not reflected within the IRP NPVRR. The Preferred Portfolio performed well in terms of cost risk relative to other portfolios. While the percent reduction of CO_2e was less than the renewables flexible gas and all renewables by 2030 portfolios, the Preferred Portfolio was near the middle of all portfolios and overwhelmingly driven by the continued use of F.B. Culley 3. As Witness Retherford explains, due to changes in environmental regulations, the Company is presently evaluating the decision to retire F. B. Culley 3 earlier than 2039. If the decision is made to retire F.B. Culley 3 early, the differences between the Preferred Portfolio and Renewables Plus Flexible Gas in terms of NPVRR and percent reduction of CO_2e are not expected to be material. Of the remaining portfolios, the Preferred Portfolio relied least on energy purchases and was among the best in terms of reliance on energy sales to the market. The Preferred Portfolio was dramatically better, at 0.4 percent, in terms of less long-term reliance on the capacity purchases, while the other three portfolios average reliance ranged from 9.4 to 11.9 percent per year. The Preferred Portfolio relied on capacity sales of 4.6 percent, which was in the middle of all portfolios.

Q. Please describe further why the Preferred Portfolio was selected.

A. The Preferred Portfolio was selected because it was determined to be a very reliable and resilient portfolio that offers a transition to a clean energy future by complementing renewable energy resources with fast start and fast ramping capability. The portfolio is a good mix of traditional and emerging resources and has enough dispatchable capacity to cover CenterPoint Indiana South's load in the winter when there is drastically less solar output during the winter peak period. This point is illustrated in Petitioner's Witness Bacalao's testimony. The Preferred Portfolio is cost effective and expected to save CenterPoint Indiana South's customers up to $320 million over the IRP's twenty-year planning period (2020 – 2039) compared to continuing to operate coal units. The Preferred Portfolio provides a physical hedge against high energy and capacity costs. As the future continues to be uncertain, this plan offers a diverse set of resources with multiple off-ramps, designed to hedge against risk of putting too much emphasis on a few large resources. While the flexible gas CTs are available to provide low cost capacity, their projected usage, largely limited to critical times, results in lower CO_2 emissions by 75 percent by 2035 over 2005 levels.

Q. Has modeling been updated since submitting the IRP on June 30, 2020?

A. No. CenterPoint Indiana South considered a wide range of potential future states within the IRP analysis to understand how the portfolios would perform if the future turns out to be different than expected. The result does not rely on a single set of assumptions that can later be invalidated by evolving market conditions. That being said, we have not seen the shifts in key inputs in recent years that would have changed the selection of the Preferred Portfolio. During the IRP, some market data suggested that solar costs may be going up. As described on page 103 of the IRP in Petitioner's Exhibit No. 5, Attachment MAR-1 "[CenterPoint Indiana South] performed a sensitivity in which the cost of solar Power Purchase Agreement ("PPA") resources increase 30 percent, based on more recent market information at the time. 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." Secondly, the period between submitting the IRP and filing this CPCN is only about 1 year. While we have seen impacts due to COVID lock downs, it is too soon to know the long-term effects. While one might argue that load could be lower going forward, that does not negate the need for two combustion turbines. [redacted] It should be noted that the Commission recently found in NIPSCO Cause No. 45462 that the mere passage of time did not invalidate their 2018 IRP. The Commission went on to state that integrated resource plans are performed at a point in time and use modeled scenarios to show how resources perform over a variety of alternative future conditions. CenterPoint Indiana South's IRP sought to understand potential changes that could affect the electric industry[5].

[5] The Commission, in its Order in Cause No. 45462, wrote: "The mere passage of time does not invalidate the 2018 IRP, nor does the fact that NIPSCO chose to submit three Solar Projects that represent its largest proposed investment to date. Inherently, integrated resource plans are performed at a point in time and use modeled scenarios to show how resources perform over a variety of alternative future conditions. This is not a case where NIPSCO performed the 2018 IRP analysis and has failed to respond to changes in the electric industry or the broader market, and now seeks approval of generation additions based on a questionable foundation." *Cause No. 45462* (IURC 5/5/2021), at p. 62

Q. Does the Preferred Portfolio rely heavily on the market for energy or capacity sales and purchases?

A. No. The Commission provided clear guidance in Cause No. 45052 that CenterPoint Indiana South should not ". . . have a one-sided view of market risk." As such, CenterPoint Indiana South included this key risk in the balanced scorecard. Portfolios that relied too heavily on the market for wholesale market sales or capacity sales were considered riskier than those that more closely aligned with retail need. Market energy and capacity sales have the effect of lowering the Net Present Value of Revenue Requirements. Effectively, portfolios that have high market energy and capacity sales are taking a chance at the customers' expense that the projected energy price will remain at or above projected levels. On the other side of the spectrum, portfolios that relied heavily on the market for long-term energy and capacity purchases were also deemed risky. Portfolios with sufficient resources to meet customer retail load and maintain sufficient capacity to meet long-term planning reserve margin requirements shield customers from market price risk. Overall, the Preferred Portfolio performed well on these score card measures.

Q. How did portfolios perform that included A.B. Brown continuation on coal or conversion to natural gas?

A. Five portfolios were created to explore options to continue utilizing existing generation at the A.B. Brown plant: BAU 2039 (continues use of Brown coal units through 2039), Bridge BAU 2029 (continues use of Brown coal units through 2029), Bridge ABB1 Conversion (conversion of 1 Brown unit to gas), Bridge ABB1 + ABB2 Conversion (conversion of both Brown coal units to gas), and Bridge ABB1 + CCGT (conversion of one Brown coal unit to gas with the addition of a mid-sized CCGT at stakeholder request). As shown in Table 4: IRP Scorecard below, these options were among the highest cost and cost risk. Additionally, portfolios that relied on continued coal burn relied the most on Market energy sales. Overall, these portfolios performed poorly compared to the Preferred Portfolio (High Technology), as shown below in Table 4: IRP Scorecard.

Table 4: IRP Scorecard[6]

	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	Excess Capacity as a % of Peak Demand
Reference Case	$2,536	$2,919	58.1%	16.8%	26.8%	9.7%	1.2%
BAU to 2039	$2,912	$3,307	35.2%	12.0%	36.5%	0.1%	11.1%
Bridge BAU 2029	$2,689	$3,090	61.9%	15.2%	31.4%	7.1%	4.3%
Bridge ABB1 Conversion + CCGT	$2,822	$3,217	47.9%	6.6%	31.8%	1.3%	10.1%
Bridge ABB1 Conversion	$2,632	$3,001	61.5%	19.2%	26.4%	9.3%	1.2%
Bridge ABB1 + ABB2 Conversion	$2,784	$3,161	61.5%	18.5%	27.5%	4.0%	5.6%
Diverse Small CCGT	$2,680	$3,071	47.9%	6.4%	31.1%	1.7%	3.7%
Renewables Peak Gas	$2,526	$2,926	77.4%	21.5%	27.7%	9.4%	1.2%
Renewables 2030	$2,613	$3,002	79.3%	26.1%	31.9%	11.9%	1.7%
High Technology	$2,590	$2,978	59.8%	16.7%	26.9%	0.4%	4.6%

Q. Have you reviewed the Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, which was published on April 9, 2021?

A. Yes. I have reviewed the report.

Q. Please describe the Director's Report.

A. Following submission of the IRP, Dr. Brad Borum Director of Research, Policy and Planning will submit a critique of the Company's IRP. The Director's Report is a tool that allows for Commission staff to provide direct feedback on the stakeholder process, analysis methodology, compliance with the rule, and clarity of communication materials, including the IRP report. Within the Director's draft report, there is also a synthesis of stakeholder comments that were provided on the Company's IRP with feedback from the Director. CenterPoint Indiana South utilizes this report to drive continuous improvement in our IRP analysis. Feedback from the prior Director's Report addressing CenterPoint Indiana South's 2016 IRP was discussed in the first of four public stakeholder meetings and informed a wide range of improvements in the 2019/2020 IRP.

Q. Please describe the major concerns raised in the 2016 Director's Report.

A. The Director raised four major concerns about the 2016 IRP in that Director's report: 1) CenterPoint Indiana South did not consider a wide range of portfolios; 2) CenterPoint Indiana South did not consider a wide enough range of gas price forecasts; 3) CenterPoint Indiana South did not perform a comprehensive risk analysis; and 4) modeling methodology concerns were raised.

[6] Includes updated Stochastic Mean 20-Year NPVRR and 95th Percentile Value of NPVRR to reflect final IRP results including corrections to 3 conversion portfolios. Additionally, Purchases as a % of Peak Demand and Excess Capacity as a % of Peak Demand for the ABB1 Conversion were inverted.

Q. Were these concerns addressed in the 2019/2020 IRP?

A. Yes. The Director did not raise these issues in the 2019/2020 IRP. In fact, he had several positive comments, many of which were in these areas. On page 25 of the draft report, the Director noted that "[CenterPoint Indiana South]'s IRP included significant advances to its processes, analysis, methodology, and software. The Director appreciates the significant changes [CenterPoint Indiana South] has made from its 2016 IRP."[7] The Director also commented on page 21 that the "…Risk and uncertainty analysis and discussion in the IRP are well done."[8] Additionally, it was noted on page 21 of the draft report that "The Director appreciates the wide range of alternative candidate portfolios that were partially optimized. Each was clearly designed to evaluate specific alternative resource strategies. Emphasis was placed on the conversion of one or both Brown units to natural gas and the acquisition of 400-500 MW of natural gas combined cycle capacity. The information from this analysis is helpful . . ."[9]

Q. Were any concerns raised about the 2019/2020 IRP?

A. Yes. The Director emphasized two concerns within the Director's draft report, . both of which I will address here. First, as indicated page 32 of the draft report:

> The Director agrees with the OUCC that the large increase in projected industrial sales in the next few years looks unusual. Utilities often make an adjustment in the first few years of an industrial load forecast to account for large changes that are thought to be missed by an econometric forecast that emphasizes historical trends and relationships. The issue of how to account for large near-term changes in load is not new.[10]

As described in the IRP, CenterPoint Indiana South utilized its internal estimate for large sales in the first 5 years of the forecast and then relied on modest long-term annual growth

[7] Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, April 9, 2021, by Dr. Bradley Borum, Director of Research, Policy and Planning on behalf of the Indiana Utility Regulatory Commission, Page 25.
[8] Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, April 9, 2021, by Dr. Bradley Borum, Director of Research, Policy and Planning on behalf of the Indiana Utility Regulatory Commission, Page 21.
[9] Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, April 9, 2021, by Dr. Bradley Borum, Director of Research, Policy and Planning on behalf of the Indiana Utility Regulatory Commission, Page 21
[10] Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, April 9, 2021, by Dr. Bradley Borum, Director of Research, Policy and Planning on behalf of the Indiana Utility Regulatory Commission, Page 32

estimates thereafter. This process ensures that CenterPoint Indiana South captures large, expected shifts in load, up or down, based on conversations/negotiations with CenterPoint Indiana South's largest active and prospective customers. Estimates from large customers not only feed CenterPoint Indiana South's integrated resource planning but also the company budget and are submitted to MISO. CenterPoint Indiana South only includes projects with the most certainty within the forecast. Large shifts in load must be accounted for outside of econometric modeling. For example, when a large customer recently installed a co-generation facility, there was a drop of about 80 MWs in the year that it was installed. CenterPoint Indiana South included the expected reduction in sales and demand within the forecast. A drop of this magnitude cannot be predicted within econometric modeling, nor is it reflective of potential future drops in large customer sales. Additionally, CenterPoint Indiana South continues to engage in confidential negotiations with potential customers for large load additions, [redacted] This large load was not included within the IRP forecast. To put it into perspective, the IRP anticipated 510,410 MWh increase in large customer load between 2019 and 2023. [redacted]

The second concern emphasized by the Director was found on page 21 of the Director's draft report; ". . . the Director would have appreciated one optimization run with a minimum of constraints or exogenous choices pre-selected. The Director recognizes the resulting portfolio might be unrealistic because it fails to adequately account for real world limitations but thinks such an exercise is still informative."[11] CenterPoint Indiana South described the limited number of constraints in section 7.2.4 Additional Modeling Considerations on pages 213-214 of Petitioner's Exhibit No. 5, Attachment MAR-1. I will describe the three most significant constraints utilized and the reasoning around each one. Ultimately, constraints help produce a portfolio that is practical, achievable, and in-line

[11] Draft Director's Report for CenterPoint Indiana South's 2019/2020 Integrated Resource Plan, April 9, 2021, by Dr. Bradley Borum, Director of Research, Policy and Planning on behalf of the Indiana Utility Regulatory Commission, Page 21

with the stated objectives of the IRP, including diversity and avoidance of risk. First, as stated on page 213 of Petitioner's Exhibit No. 5, Attachment MAR-1:

> [CenterPoint Indiana South] received approval in 2019 from the Commission to upgrade F.B. Culley 3, [CenterPoint Indiana South'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. [CenterPoint Indiana South] 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.

Second, CenterPoint Indiana South included a few constraints around renewable resources. CenterPoint Indiana South conducted an All-Source RFP to obtain renewable pricing per previous Commission guidance and received bids for solar and wind resources. CenterPoint Indiana South limited the amount of these resources that could be selected within modeling based on a few considerations. CenterPoint Indiana South did not allow for more of these resources than available projects from the All-Source RFP. Competition for resources is high, and many of the bids that came in were very early in development and speculative. CenterPoint Indiana South did not intend to do self builds for these resources, so it would be impractical to allow the model to select more solar and wind than the market would bear in the early years. Additionally, CenterPoint Indiana South limited the amount of solar resources that could be selected through 2024 to 1,150 MWs (roughly the amount of CenterPoint Indiana South's peak load in the summer). As described on page 250 of Petitioner's Exhibit No. 5, Attachment MAR-1:

> 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 [through 2024] was also limited by practical considerations around logistics and operational feasibility.

Third, CenterPoint Indiana South included a constraint that was described on pages 99-100 of the Petitioner's Exhibit No. 5, Attachment MAR-1.

> Market transactions offer supply flexibility but also exposure to potential market risk to [CenterPoint Indiana 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 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 CenterPoint Indiana South did not fully consider energy or capacity purchases.

Modeling is simply a tool to aide in the decision-making process. While an unconstrained model run may provide some information that is useful for the analysis, it will not provide the answer to the IRP analysis. The constraints utilized within the IRP helped produce a wide range of potentially viable portfolios for use within the analysis. Had these constraints not been put into place, the resulting portfolio would have been screened out before probability modeling. Optimization modeling is time consuming and expensive. Reasonable constraints help make the analysis more efficient. Nevertheless, CenterPoint Indiana South has agreed to an unconstrained modeling run in the next IRP.

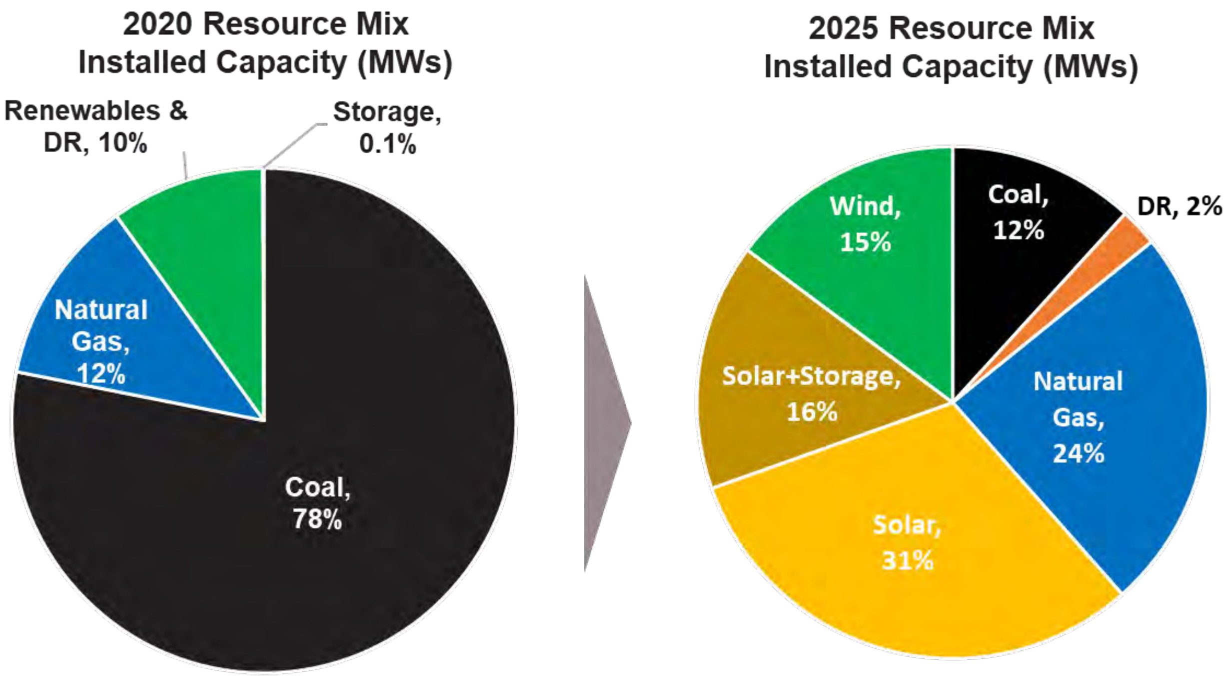
IV. THE PREFERRED PORTFOLIO

Q. What are the major components of the Preferred Portfolio?

A. The Preferred Portfolio is very diversified, with significant amounts of solar, solar plus storage, wind, gas, coal, demand response, and energy efficiency. Specifically, it includes energy efficiency at 1.25 percent between 2021-2023 and 0.75 percent[12] thereafter. The portfolio calls for 300 MW of wind resources to come online in 2022. It also calls for 1,150 MWs of new solar and solar plus storage in 2023-2024 to replace coal capacity, including Warrick Unit #4 which Petitioner jointly operates with Alcoa. Additionally, two CTs come online in 2024-2025. In 2039, 50 MW of storage was selected. The illustration below in Figure 5 shows the Preferred Portfolio's mix of installed capacity.

[12] The level of EE for 2024 and beyond will be decided with future IRPs and DSM filings.

Figure 5: Preferred Portfolio Resource Mix



Q. What are the primary benefits of the Preferred Portfolio?

A. The Preferred Portfolio includes a diverse mix of resources. The risk analysis demonstrated that a diversified mix of generation resources minimizes risk to customers if the future differs from the Reference Case scenario. As described in the final stakeholder meeting on June 15, 2020, and the 2019/2020 IRP, the Preferred Portfolio has the following characteristics: reliability, cost effectiveness, flexibility, diversity, risk mitigation, sustainability, and timeliness.

Q. Why did the Preferred Portfolio rank the best in the risk analysis?

A. Benefits of the Preferred Portfolio are spelled out in detail in Section 9 of the IRP (Petitioner's Exhibit No. 5, Attachment MAR-1) and include affordability, cost uncertainty risk mitigation, environmental risk mitigation, market risk mitigation, future flexibility, reliability, operational flexibility, resource diversity, local resources, and economic development for the CenterPoint Indiana South territory and the state of Indiana. As I mentioned earlier, the Preferred Portfolio performed well across multiple risk factors in the balanced scorecard. It avoids long-term reliance on the capacity market or heavy reliance on emerging technology. The fast start and ramping capability of CTs allows for high penetration of low-cost renewable energy resources, which were consistently selected for all portfolios, regardless of potential future events. It also allows CenterPoint Indiana South to incrementally pursue renewable build out with confidence that dispatchable resources will be available when needed, particularly in winter months where multi-day periods of cloud cover and no wind are possible.

Q. What factors support replacing the generation provided by F.B. Culley 2, Warrick Unit #4, and A.B. Brown units 1 & 2?

A. As described in Petitioner's Witness Wayne D. Games' testimony, F.B. Culley 2 is CenterPoint Indiana South's smallest and least efficient coal unit. It does not compete economically in the MISO market and needs costly upgrades to continue operation many years beyond 2023. Even the Indiana Coal Council ("ICC") acknowledged in their recent comments on CenterPoint Indiana South's 2019/2020 IRP, "There is no dispute over whether it should be retired. . . ."[13] Also, CenterPoint Indiana South's contract with Warrick Unit #4 expires on December 31, 2023, and IRP modeling found extension of the contract was not economical. These two units currently provide 240 MW of installed capacity, 206 MW of which counts towards MISO's planning reserve margin ("PRM") requirement for the 2020 – 2021 planning year. While the Petitioner might be able to find economical ways to keep these units running for a year or two longer to help meet its capacity needs, long-term reliance on these units is not the most economical answer for customers.

As described in Petitioner's Exhibit No. 5, Attachment MAR-1 on page 164 of the IRP, A.B. Brown units 1 & 2 utilize dual alkali scrubbers, which present several operational challenges, including: high variable production costs relative to industry standard limestone-based scrubbers, high maintenance costs due to the corrosive dual-alkali process, and challenges in obtaining support and replacement parts for these last of their kind scrubbers. These two units currently provide 500 MW of installed capacity, 466.1 MW of Unforced Capacity ("UCAP") which counts towards MISO's PRM requirement for the 2020 – 2021 planning year.

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[13] ICC comments on CenterPoint Indiana South's 2019/2020 IRP submitted to Director Dr. Bradley Borum on October 28, 2020, bottom of page 6.

Q. What short-term steps does the Preferred Portfolio require CenterPoint Indiana South to take?

A. The Preferred Portfolio calls for CenterPoint Indiana South to pursue renewable projects within the next three years based on the retirement of F.B. Culley 2 and for the expiration of the contract for joint operation of Warrick Unit #4 in December 2023. Adding renewable projects during this time frame has the added benefit of allowing CenterPoint Indiana South customers to take advantage of renewable tax incentives before they expire. Additionally, the plan calls for two combustion turbines equaling approximately 460 MWs of dispatchable installed capacity to replace A.B. Brown units 1 & 2, along with additional renewable wind and solar resources. The Preferred Portfolio also called for capacity purchases to help meet the planning reserve margin requirement during the time in which A.B. Brown units 1 & 2 are retired and the combustion turbines come online.

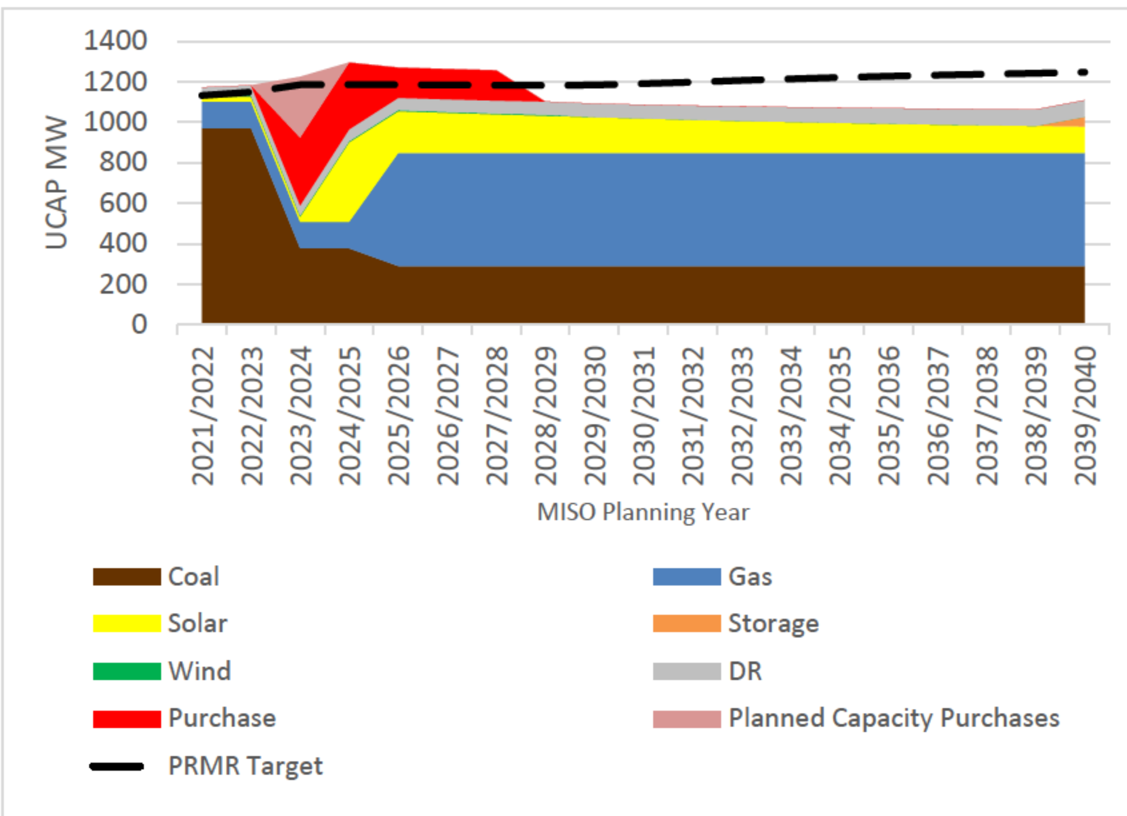
Q. Has CenterPoint Indiana South taken steps to begin implementing the Preferred Portfolio?

A. Yes. Consistent with the short-term action plan in the 2019/2020 IRP, CenterPoint Indiana South selected two projects from the All-Source RFP conducted on June 12, 2019 and filed for these projects in Cause No. 45501. The Posey County Solar Project and Warrick County Solar Project (collectively, the "45501 Solar Projects") were selected. Definitive agreements have been signed for the projects. Additionally, as discussed in Petitioner's Witness F. Shane Bradford's testimony, CenterPoint Indiana South, has begun securing needed capacity through bilateral contracts to ensure CenterPoint Indiana South maintains its PRM requirement while the combustion turbines are constructed. Contingent on approval in this proceeding, CenterPoint Indiana South conducted an RFP for the construction of the CTs and has negotiated a contract to provide firm gas service to the A.B. Brown site to supply the CTs. Finally, CenterPoint Indiana South is in the final stages of evaluating results of a second RFP to secure additional renewable resources identified in the Preferred Portfolio.

Q. Does the Preferred Portfolio offer future flexibility should the future turn out differently than expected?

A. Yes. While the Preferred Portfolio performed consistently well across a wide range of futures, flexibility to pivot is built into the plan. While modeling selected 1,150 MWs of solar and solar plus storage, CenterPoint Indiana South is initially pursuing ~700-800 MWs of a mix of solar ownership and PPAs of varying term lengths from 15-25 years while CenterPoint Indiana South evaluates MISO's future for resource accreditation. Additionally, the Preferred Portfolio included F.B. Culley 3 coal unit through 2039; as Witness Retherford explains, due to a change in regulations, Petitioner is presently evaluating the potential to retire this unit sooner. As described in Witness Bradford's testimony, CenterPoint Indiana South has made capacity purchases to enable the generation transition plan. At the end of these purchases in the 2027/2028 planning year, there is expected to be an additional need that could be filled with additional PPAs, DR, or owned resources. The capacity purchases are illustrated below in Figure 6: Generation Transition Plan.

Figure 6: Generation Transition Plan[14]



[14] Includes Culley 3 through 2039; existing coal, gas, DR and solar resources; 735 MWs of new installed solar capacity, 300 MWs of installed wind capacity, and new 460 MWs of gas CTs. Amount may vary as negotiations continue for resources. Also includes ELCC expectations from the IRP. As more solar penetrates the MISO market, the capacity accreditation is expected to decline.

Finally, the resources included in the Preferred Portfolio are flexible. For instance, should battery prices come down or it make sense to add a large battery to one of our solar fields, this is possible. Also, CenterPoint Indiana South selected GE F-class turbines for the two new combustion turbines. As discussed in Witness Games' testimony, these units can currently burn 30% hydrogen from renewable energy with modifications, thereby lowering the small amount of CO_2 that is expected to be produced from these capacity resources. CenterPoint Indiana South's diverse portfolio is well positioned for the future.

V. COMBUSTION TURBINES PROJECT

Q. Please briefly describe the Combustion Turbines Project.

A. As described in Witness Games' testimony, CenterPoint Indiana South selected F Class CTs through a competitive procurement process. This class of turbines have been in the market for over 30 years and have a proven history of solid and reliable performance. The units are capable of starting in as little as 10 minutes and can ramp 40 MWs per minute, per unit, or 80 MWs per minute. CTs are low cost capacity resources identified in the Preferred Portfolio, supporting intermittent renewable resources in a diverse portfolio.

Q. Have you reviewed the IURC's Statewide Analysis of Future Resources for Electricity ("Statewide Analysis")?

A. Yes. I understand the Statewide Analysis is ongoing and that the most current written version of that analysis is dated 2018. A copy is attached as Petitioner's Exhibit No. 5, Attachment MAR-16.

Q. In your opinion, is the Combustion Turbine Project for which a CPCN is being sought in this proceeding consistent with the Statewide Analysis?

A. Yes. That Analysis cautions that it is not to be construed as an energy plan and it does not predetermine resource decisions. In general, it provides information to various stakeholders. Our proposed Combustion Turbine Project is consistent with the Statewide Analysis, although the data and analysis underlying our proposal has continued to develop since the written Statewide Analysis was completed.

Q. In your opinion, is the Combustion Turbine Project consistent with CenterPoint Indiana South's 2019/2020 IRP?

A. Yes. Two combustion turbines were identified in the Preferred Portfolio to provide low cost capacity to support the low-cost renewable energy resources and help replace 730 MWs of coal generation. The CTs are part of a balanced mix of renewables, gas, coal, and Demand Side Management ("DSM") resources to serve customers, identified in the 2019/2020 IRP.

Q. Does the Combustion Turbines Project fulfill a capacity need identified in CenterPoint Indiana South's 2019/2020 IRP?

A. Yes. The Combustion Turbines Project directly replaces approximately 460 MWs of dispatchable capacity that results from closing A.B. Brown units 1 & 2, which was identified in CenterPoint Indiana South's 2019/2020 IRP. As Petitioner's Witness Retherford describes in her testimony, it is not feasible to continue running A.B. Brown units 1 & 2 until the 2025/2026 planning year (period of time needed to construct the CTs).

Q. What are the benefits of adding combustion turbines generally?

A. The combustion turbines provide several benefits to the Preferred Portfolio. First, they are a part of a diverse mix of resources, which helps to shield customers from risk. Second, combustion turbines compliment renewable resources by providing quick start and fast ramping capability, which is a dramatic improvement over existing coal generation. These attributes, along with the ability to load follow on partially cloudy days supports the build out of solar generation. As solar resources continue to increase in the MISO market, the net peak hour is expected to shift into the evening hours. If needed, CTs may be called upon to help meet this demand as the sun falls behind the horizon; the ability to ramp quickly is important to address the duck curve.[15] Third, combustion turbines provide resilience to the Preferred Portfolio. Dispatchable capacity is needed for long durations when the sun is not shining and the wind is not blowing, particularly in the winter. MISO recently reiterated that the capacity market is moving to a seasonal construct where various resources will receive varying capacity accreditation, depending on the season.

[15] The duck curve is the graphic representation of solar penetration which pushes the net peak load into mid/late evening. Quick ramping resources are needed to meet this phenomenon.

Gas turbines with firm gas service are expected to have a higher accreditation in the winter at ~95%, while solar is expected to receive approximately 5%.[16] CenterPoint Indiana South's Preferred Portfolio will retain enough dispatchable capacity to meet its expected winter load. During the summer, when load increases, capacity accreditation is expected to slightly decrease for gas and increase for solar.

Fourth, the combustion turbines are a physical hedge on the capacity and energy markets. When volatility occurs with high energy prices, CTs are available to shield customers from high cost. Other top portfolios had a long-term reliance on the capacity market, which is risky for CenterPoint Indiana South customers. In addition to being called upon when market energy prices are high, they are also available to be called upon for reliability issues; however, IRP modeling suggests that these units will not run much, which keeps CO_2 output very low. Finally, CTs provide for future flexibility to burn hydrogen in the long-term. As mentioned by Witness Games, the GE units CenterPoint Indiana South selected have the ability to burn 30% hydrogen today with modifications.

Q. Does CenterPoint Indiana South also need to move to a balanced mix of resources in its portfolio in general?

A. In my opinion, yes. CenterPoint Indiana South believes there is value in a balanced portfolio to reduce risk by having a diverse set of resources available to serve customer load (including not only diversity in generation resources but also DSM). The benefits of a balanced energy mix cannot be overstated. One of the simplest and best ways to plan in an uncertain environment is to provide a diverse portfolio, which provides a hedge against unforeseen changes in regulations, technologies, and market.

Q. Did CenterPoint Indiana South consider DSM as a resource in its 2019/2020 IRP?

A. Yes. CenterPoint Indiana South considered DSM as a resource in its 2019/2020 IRP and included DSM in the Preferred Portfolio. CenterPoint Indiana South considers DSM to be part of a balanced utility resource plan.

[16] MISO, RAN Reliability Requirements + Sub-annual Constructs presentation, RASC, February 3, 2021-updated February 25, 2021, page 22.

Q. In your opinion, are DSM initiatives a viable alternative to completing the CTs identified in the Preferred Portfolio?

A. No. The 2019/2020 IRP demonstrates that DSM will be an important part of CenterPoint Indiana South's resource options in the future. However, the IRP also recognizes that the addition of renewable and gas resources is necessary to meet the needs of the system in the future and to diversify Petitioner's generation portfolio. DSM initiatives may prove to be a viable alternative to future capacity needs. The Preferred Portfolio shows a need for further capacity to meet the forecasted PRM after our short-term actions are complete, and that need would be more if the decision is made to retire F.B. Culley Unit 3 sooner, as being explained by Witness Retherford.

Q. In your opinion, is the addition of the CT Project to CenterPoint Indiana South's generation portfolio in the public convenience and necessity?

A. Yes. The CT Project is consistent with CenterPoint Indiana South's 2019/2020 IRP and is an economic choice to help meet CenterPoint Indiana South's retail electric load 24 hours a day, 365 days a year. The expected capacity attributable to the CT Project is necessary to meet CenterPoint Indiana South's load and adequate reserve margins, particularly in the winter. In addition to providing necessary capacity, the CT Project is a reasonable addition to a portfolio of capacity resources that in the aggregate serve to mitigate risk through diversification. Commission approval of the CT Project and associated relief sought herein is in the public interest and will enhance or maintain the reliability and efficiency of service provided by CenterPoint Indiana South.

Q. Please describe some of the key quantitative and qualitative considerations as to why continuing to run A.B. Brown or converting A.B. Brown is not a good option relative to building two new combustion turbines.

A. As described in the final IRP stakeholder meeting on June 15, 2020, these options are less affordable to customers due to high O&M and on-going capital expenditures to keep the units running. This was evident in the long-term NPVRR for these portfolios as well as near term bill impacts (discussed further below). The NPVRR of converting both A.B. Brown units to gas was $2,784 million, and the NPVRR of running both A.B. Brown units until 2029 was $2,689 million, which was $193 million to $98 million more than replacing the A.B. Brown coal units with two natural gas CTs.

Operationally, these options have a worse heat rate than new combustion turbines, which drives the need to burn more fuel. The heat rate of gas conversion is approximately 11,000 BTU/kwh, and the heat rate for continuing to run A.B. Brown through 2029 is approximately 10,600 BTU/kwh. Both are less efficient than CTs at approximately 9,900 BTU/kwh.

Additionally, there is less operational flexibility when market prices spike suddenly; converted gas units or coal units cannot start and warm up quickly enough to shield customers from potential high costs. As discussed in Witness Games' testimony slow start times (16-24 hrs.) and slow ramp rates (2-6 MW/Min), which does not position us well to support high penetrations of solar that is expected in and around our service territory, regardless of who owns and operates solar plants. The conversion of the A.B. Brown units locks in our inability to respond quickly when needed. As described by Witness Bradford, MISO's recent market reforms and products pay a premium for resources that can be called upon quickly. He also notes that MISO's Independent Market Monitor recently described the need for significant ramping capability to support solar resources. Witness Games noted that coal units are not made to ramp up and down quickly, and this tends to drive more costs as such causes equipment to wear out more quickly than if the units were able to run as designed (base load units). The CTs on the other hand start within 10 minutes and together have the collective ability to ramp 80 MWs per minute.

Finally, this equipment is old and more prone to break down than new combustion turbines. This is partially why on-going O&M capital spend is necessary, but as Witness Games testifies to the A.B. Brown units have corrosion issues due to chemicals needed to run outdated environmental equipment. When these failures occur, they can have an impact on MISO accreditation.

Q. Why is the Preferred Portfolio with two combustion turbines a better option for customers than the Reference Case, which only has one combustion turbine.

A. Two highly dispatchable combustion turbines allow for a high penetration of renewable resources, ensuring reliability and better hedges against the energy and capacity markets. For example, as described in Witness Bradford's testimony, when there is an unexpected constraint on the transmission system, LMPs can spike to high levels. The CTs will have the ability to turn on quickly and shield CenterPoint Indiana South customers from price volatility.

With two combustion turbines, CenterPoint Indiana South has enough dispatchable resources to meet the winter peak. This is important, as MISO continues to move towards a seasonal capacity construct. Solar resources are expected to receive only 5% of their installed capacity using this MISO planning assumption; of the first 735 MWs of solar installed capacity that CenterPoint Indiana South is pursuing, approximately 37 MWs would count towards the anticipated winter planning reserve margin requirement. It is possible that solar could receive zero accreditation in the winter.

Two CTs will help to better ensure reliability when there are multiday periods of cloud cover and no wind. CTs provide affordable capacity and are available to run for long durations when needed. Conversely, energy storage options are higher priced capacity resources than CTs, and they only typically provide enough power for a 4-hour duration. To provide 8 hours' worth of power, the cost nearly doubles. Additionally, Witness Bacalao describes how widespread adoption of storage is expected to decrease storage capacity accreditation in MISO. This risk factor was not considered in the IRP.

Two CTs provide double the ramping capability than one does to better support intermittent solar locally and on the MISO system to meet the evening net peak. Two CTs are able to start within 10 minutes and can ramp at 80 MW/minute versus 40 MW/minute with one CT. They are also load following.

Q. The Renewables Plus Flexible Gas waits to build the second CT in the mid 2030's. Is there an advantage to building two now?

A. Yes. In addition to the benefits mentioned above, there are construction efficiencies in building the units at the same time. As shown in Technical Appendix Attachment 1.2 Vectren Technology Assessment Summary table from <u>Petitioner's Exhibit No. 5</u>, Attachment MAR-2, the second CT is estimated to be approximately $50 million less capital spend than the second CT when built at the same time. Additionally, building two CTs at the same time keeps existing interconnection rights at A.B. Brown, which shields customers from potential transmission upgrade costs in the future should CenterPoint Indiana South have to re-enter the MISO Queue (a two and a half to three-year process).

VI. 21st CENTURY ENERGY POLICY DEVELOPMENT TASK FORCE PILLARS

Q. Have you reviewed the Final Report issued by the 21st Century Energy Policy Development Task Force dated November 19, 2020 (the "Final Report")?

A. Yes. I reviewed the five pillars that the Task Force recommended serve as a lens through which it would review future potential policy decisions.

Q. What are the five pillars?

A. The five pillars are reliability, resilience, stability, affordability, and environmental sustainability. Reliability consists of two fundamental concepts – adequacy and operating reliability. Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components. Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components.

Q. In your opinion, is the proposal in this proceeding consistent with those five pillars?

A. Yes. The combustion turbines support the addition of clean renewable energy. This is consistent with the environmental sustainability pillar set forth in the Final Report. The total CO_2 output of the combustion turbines is minimal as these units are there for backup and not expected to run much. Moreover, as further supported by the IRP, this project promotes reliability. The Preferred Portfolio provides adequate, dispatchable capacity to meet MISO's planning reserve margin requirements in the summer and the winter in anticipation of a seasonal capacity requirement. The CTs can also supply power and energy requirements when called on by MISO for reliability or when market prices are sufficiently high, shielding customers from price risk. As Petitioner's Witness Games notes, CenterPoint Indiana South proposes to pair renewable generation with quick start and fast ramping dispatchable natural gas CT generation, which will further enhance the ability of the system to withstand sudden disturbances.

Q. In your opinion, is the Preferred Portfolio resilient and stable?

A. Yes. As to resiliency, the Preferred Portfolio helps to minimize the risk of sustained disruption. As further discussed by Petitioner's Witness Bacalao the IRP resulted in a Preferred Portfolio that significantly, but prudently, diversifies the resource mix for CenterPoint Indiana South's generation portfolio to meet current and future load and reserve margin requirements. Reliability was an important consideration of selecting a holistic portfolio. Solar, wind, natural gas combustion turbine, and coal resources are proven technologies that will help ensure CenterPoint Indiana South can continue to meet PRM requirements. Solar assets are also well suited to provide a stable source of energy in the summer when usage is at its highest. This is balanced with sufficient dispatchable resources to meet winter load. The new combustion turbines will include firm gas service to help ensure adequate gas supply in the winter.

Q. Do you believe the Preferred Portfolio will result in an affordable generation mix?

A. Yes. As demonstrated in the IRP, the Preferred Portfolio was among the most affordable options for customers, regardless of the future we face. As shown in Figure 8-2 on page 246 of the Petitioner's Exhibit No. 5, Attachment MAR-1, also shown below in Table 5, pricing for the Preferred Portfolio was within approximately 1-2% of the Reference Case portfolio in scenarios with varying levels of CO_2 cost, gas costs, coal costs, load, etc. The price of other portfolios evaluated in this analysis swing more depending on the future state. For example, the All Renewables by 2030 or the BAU portfolios are less stable. As discussed later in my testimony, the Preferred Portfolio also minimizes bill impacts in the near term compared to continuing to run the A.B. Brown units through 2029 or conversion to natural gas.

Table 5: Portfolio NPVRR (million $)[17]

	Scenarios				
	Reference	**Low Regulation**	**High Technology**	**80% Reduction of CO_2 by 2050**	**High Regulatory**
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	110.6%	110.7%	109.6%	109.1%	106.0%
ABB1 Conversion	102.2%	102.9%	102.8%	102.1%	100.8%
ABB1 + ABB2 Conversions	108.1%	108.1%	108.2%	107.8%	104.1%

[17] Conversion portfolios (Bridge ABB1 Conversion + CCGT, Bridge ABB1 Conversion, and Bridge ABB1 + ABB2 Conversion) were updated. Updates are included in the table.

Diverse Small CCGT	105.3%	105.3%	104.2%	103.5%	102.7%
Renewables + Flex ble 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%

Q. Is the Preferred Portfolio environmentally sustainable?

A. Yes. The Preferred Portfolio 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. Additionally, the Preferred Portfolio 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.

Q. Is the Preferred Portfolio reliable?

A. Yes. CenterPoint Indiana South's balanced portfolio includes a diverse mix of resources with enough dispatchable generation to meet peak demand in the early evening hours during the summer, when the sun goes down, and during winter peak conditions. These resources include F.B. Culley 3 coal, A.B. Brown 3 & 4 gas peaking units, and two new highly dispatchable gas turbines with firm gas service. These units provide fast start (10 minute) and fast ramping capability (40 MW/minute each CT or 80 MW/minute for both CTs), which compliments renewable resources when needed. A reliability assessment was performed as part of the Preferred Portfolio, discussed on pages 197-198 of <u>Petitioner's Exhibit No. 5</u>, Attachment MAR-1. CTs provide sufficient reactive power reserves[18] to minimize potential voltage issues. Finally, CenterPoint Indiana South's transmission system has 750 MWs of import capability, which allows CenterPoint Indiana South to utilize the system to provide power when market prices are low.

VII. <u>COST ISSUES</u>

[18] Real power accomplishes useful work while reactive power supports the voltage that must be controlled for system reliability.

Q. Do the cost estimates for the combustion turbines align with the IRP cost estimates?

A. Yes. The capital costs and expected O&M costs in this filing align with the previous IRP estimates. The following provides more detail.

Q. How do the cost assumptions associated with the combustion turbines modeled in the IRP compare with the cost of the +/- 10% cost estimates described in Witness Games' testimony?

A. The cost estimate for the two CTs in the IRP was approximately $327.8 million in 2024 dollars, which is higher than the cost of two CTs requested in this case at $323 million, as described in Wayne Games' testimony.

Q. Did you model the cost of firm gas service within the IRP?

A. Yes, as described by Witness Paula J. Grizzle, the estimate for firm gas service is approximately $27.3 million per year in 2024 dollars. This was lower than the amount included in IRP modeling at $28.6 million per year in 2024 dollars.

Q. How does the O&M estimate compare to the IRP?

A. IRP O&M estimates were utilized from the Burns and McDonnell Technology Assessment found in IRP Volume 2 attached as Petitioner's Exhibit No. 5, Attachment MAR-1. O&M projections vary by how much the unit is started and operated. Utilizing a comparable amount of starts and run time[19], O&M estimates in Witness Games' testimony are lower than what was modeled within the IRP. For the purposes of rate impact estimates, discussed below, IRP O&M assumptions were utilized.

VIII. RATE ISSUES

Q. Have you estimated the potential bill impact of the combustion turbines?

A. Yes, I provide day one bill impact estimates for the combustion turbines compared to possible alternatives such as conversion of A.B. Brown units 1 & 2 to natural gas or

[19] Conservatively assumes 150 starts per year, per unit with a 10% annual capacity factor. The IRP Reference Case capacity factor was approximately 2% over the forecast period.

running the A.B. Brown units with coal through 2029. Additionally, I provide an estimate for the total day one bill impact for the generation transition.

Q. When will CenterPoint Indiana South begin recovery of the two combustion turbines?

A. Recovery would begin following a decision in the next general rate case, which is required by the end of 2023.

Q. Please describe Petitioner's Exhibit No. 5, Attachments MAR-3 through MAR-15.

A. Petitioner's Exhibit No. 5, **Attachment MAR-3**, Low End Estimated Net Monthly Rate Impact by Customer Class, is a summary table showing the low end of projected bill impacts based on closing F.B. Culley 2, Warrick Unit #4, A.B. Brown 1 & 2 coal units and replacing them with the two CTs proposed in this case, 300 MW Posey Solar, 100 MW Warrick Solar, 335 MWs of solar PPAs, and 200 MWs of owned wind. Additionally, it shows a high-level estimate of the anticipated impact of securitization from the recently enacted Senate Bill 386. The net impact to expected revenue requirements is then allocated by customer class using current Four-Coincident Peak ("4CP") allocations, approved in Cause No. 43354-MCRA 21-S1.

Petitioner's Exhibit No. 5, **Attachment MAR-4**, High End Estimated Net Monthly Rate Impact by Customer Class, includes all projects listed above with the addition of a 130 MW owned solar plant and an additional 150 MWs of wind project. The net impact to expected revenue requirements is then allocated by customer class using current 4CP allocations.

Petitioner's Exhibit No. 5, **Attachment MAR-5**, Low End Estimated Net Monthly Rate Impact by Customer Class – Existing Allocations, shows the net impact by customer class utilizing current 4CP (capacity based) allocations for owned projects and FAC proxy (energy based) allocations for the low end estimate projects listed above in Petitioner's Exhibit No. 5, Attachment MAR-3.

Petitioner's Exhibit No. 5, **Attachment MAR-6**, High End Estimated Net Monthly Rate Impact by Customer Class – Existing Allocations shows the net impact by customer class utilizing current 4CP (capacity based) allocations for owned projects and FAC proxy (energy based) allocations for the high end estimate projects listed above in Petitioner's Exhibit No. 5, Attachment MAR-4.

Confidential Petitioner's Exhibit No. 5, **Attachments MAR-7 (CONFIDENTIAL)** through **MAR-13 (CONFIDENTIAL)** show Project details for each potential resource in the generation transition and the estimated revenue requirement for each.

Petitioner's Exhibit No. 5, **Attachment MAR-14**, BAU 2029 – Continue ABB1 & ABB2 Project, and Petitioner's Exhibit No. 5, **Attachment MAR-15**, Conversion of ABB1 & ABB2 Coal to Gas Project, show the project cost details for these options, including an estimated revenue requirement for these alternatives as a comparison to building 2 CT's.

Q. Please describe the bill impact focusing just on the addition of the combustion turbines without considering any cost reduction offsets.

A. Petitioner's Exhibit No. 5, Attachment MAR-11 shows that the estimated residential year-one bill impact for a residential customer that uses 1,000 kWh per month is approximately $23 per month. This impact focuses simply on adding the two CTs and does not reflect offsets for sales or O&M and fuel savings from exiting the A.B. Brown units one and two.

Q. How does this compare to the bill impact of converting A.B. Brown 1 & 2 to natural gas or continuing to run these units with coal?

A. As described in the IRP, converting one or both A.B. Brown units to natural gas costs customers more in the long run. Conversion also costs customers more on day one. Petitioner's Exhibit No. 5, Attachments MAR-14 and MAR-15 show that the estimated residential year-one bill impact for a residential customer that uses 1,000 kWh per month is approximately $26 per month for conversion and $35 per month for continuing to run with coal through 2029, respectively. This impact for conversion does not reflect offsets for sales or O&M and fuel savings from exiting the A.B. Brown units 1 & 2 in the case of the conversion. In other words, these are the day one impacts that would be comparable to the $23 per month shown in Attachment MAR-11.

Q. You testified that all three of the calculations you have discussed so far do not reflect offsets. Please describe the expected day-one bill impact of implementing the full generation transition plan, including the impact of offsets.

A. The generation transition plan includes closing 730 MWs of coal and replacing with 735-865 MWs of solar, 200-350 MWs of wind, and the two combustion turbines proposed in this case. The plan also calls for securitization of the remaining net book value of the A.B. Brown plant at retirement. The day-one bill impact of the plan is expected to be modest for the generation portion of customer rates, ranging from a $4 million dollars decrease per year to an increase of $40 million dollars per year in the near term and is expected to decrease in the long-term.

Q. Please provide the detail associated with the Bill impact.

A. The tables below show combined savings in millions of dollars for O&M and fuel savings associated with the closure of 730 MWs of coal, removal of A.B. Brown from rate base (securitization), and the sale of Renewable Energy Credit (REC) sales associated with new wind and solar renewable resources to help offset cost to the customer. Impacts are presented in a range based on how successful CenterPoint Indiana South is at procuring renewable resources. The following tables are included in Petitioner's Exhibit No. 5, Attachments MAR-3 and MAR-4.

Table 6: Low End Summary of Generation Transition Impact Annual Savings and Costs in Millions of Dollars[20]

Description	Savings (Millions $)	Cost (Millions $)	Total (Millions $)
Expected O&M and Fuel Savings from C2, W4, ABB 1&2	($143)		
460 MW Combustion Turbine		$79	
300 MW Posey *	($5)	$37	
100 MW Warrick *	($2)	$10	
335 MW Solar PPA *	($6)	$28	
200 MW Wind *	($5)	$36	
Securitization	($56)	$23	
Subtotal	($217)	$213	
Net Cost in millions			($4)

*REC Sale Savings

[20] Estimated rate impact includes Culley 2 through 2023.

Table 7: High End Summary of Generation Transition Impact Annual Savings and Costs in Millions of Dollars[21]

Description	Savings (Millions $)	Cost (Millions $)	Total (Millions $)
Expected O&M and Fuel Savings from C2, W4, ABB 1&2	($143)		
460 MW Combustion Turbine		$79	
300 MW Posey *	($5)	$37	
100 MW Warrick *	($2)	$10	
335 MW Solar PPA *	($6)	$28	
130 MW Solar Owned *	($2)	$18	
200 MW Wind *	($5)	$36	
150 MW Wind *	($4)	$32	
Securitization	($56)	$23	
Subtotal	($223)	$263	
Net Cost in millions			$40

*REC Sale Savings

Q. How will these savings be allocated across customer classes?

A. That will depend on the rate case in 2023 and the associated class cost of service study. However, if bill impacts are spread across customer classes utilizing current 4CP allocations, customers would see the following high-level monthly bill impacts.

Table 8: Summary of Generation Transition Low End Impact Monthly Bills by Class[22]

Day-One Monthly Bill Impact	Customers	4CP Allocations	Monthly Bill Impact 4CP
Residential	132,669	41%	($1)
Small General Service	10,118	2%	($1)
Demand General Service	8,204	28%	($10)
Off Season Service	742	2%	($9)
Large Power	117	26%	($700)
High Load Factor	2	1%	($1,300)

[21] Estimated rate impact includes Culley 2 through 2023.
[22] Estimated rate impact includes Culley 2 through 2023.

Table 9: Summary of Generation Transition High End Impact Monthly Bills by Class[23]

Day-One Monthly Bill Impact	Customers	4CP Allocations	Monthly Bill Impact 4CP
Residential	132,669	41%	$10
Small General Service	10,118	2%	$6
Demand General Service	8,204	28%	$112
Off Season Service	742	2%	$96
Large Power	117	26%	$7,500
High Load Factor	2	1%	$14,800

Q. Is it possible that these impacts could look different?

A. Yes. We have done preliminary analysis for securitization, reflected in the table above, with high level estimates for securitization costs, including cost of removal for the A.B. Brown plant, which will require a decommissioning study. The cost for securitization could be higher. But the effects of higher decommissioning would be reflected in other portfolios, because as I understand it, those higher decommissioning costs would be reflected in higher depreciation rates if the A.B. Brown units were retained as coal units or converted to gas. Additionally, CenterPoint Indiana South is including costs associated with owned renewable resources through CECA (allocations are capacity based – 4CP) and PPA renewables though the FAC (energy based). Simply utilizing the current allocation methodology though CECA and the FAC, residential and commercial customers would see a larger decrease, while LP customers could see an increase of approximately 0.8 cents to 1.4 cents per kWh. Finally, I've included an $8 estimate per MWh for REC sales. This is a reasonable estimate, but the REC market could fluctuate up or down in the future. Current practice is to sell RECs on behalf of CenterPoint Indiana South customers. CenterPoint Indiana South could choose to not sell RECs in the future or be utilized in a green energy tariff for customers.

Q. When do you plan to file for securitization for the A.B. Brown Plant?

A. We could file as early as first quarter of 2022. In this filing we will seek authority from the Commission to remove the A.B. Brown plant from rate base, along with decommissioning costs, and costs associated with securing a bond when the proceeds from securitization

[23] Estimated rate impact includes Culley 2 through 2023.

are received. CenterPoint Indiana South will then charge customers for the bond for a set amount of time. The interest rate on the bond will be substantially lower than the weighted average cost of capital in a rate case. Securitization is expected to provide a benefit to all customer classes.

Q. On the subject of costs, is the Company incurring significant costs related to the planning and preparation of this proceeding and request?

A. Yes. As should be well understood, the IRP process has become much more robust over the past several IRPs. The end result is a much better tool to guide resource planning, but it comes at significant cost. And to take the planning from the IRP and further refine for approval of generation is also much more involved than it has been in past years, with the use of outside consultants and studies to explore alternatives.

Q. **How are these costs expected to be recovered?**

A. We are currently carrying these costs on our books and will record them to the cost of owned generating resources, a portion of which will be applied to the new CTs. These costs are included in the estimate of costs of the CTs presented by Witness Games. If for whatever reason the CTs are not ultimately placed in service, we are seeking authority to defer these costs as a regulatory asset at that time to be recovered as described by Witness Kara R. Gostenhofer.

IX. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, at the present time.

Low End Estimated Net Monthly Rate Impact by Customer Class
Generation Transition with Securitization & CTs[1]
With Net Savings from Culley 2, Warrick 4, AB Brown 1&2 Coal Units

Line	Description	Savings (Millions $)	Cost (Millions $)	Total (Millions $)
1	Expected O&M and Fuel Savings from C2, W4, ABB 1&2	($143)		
2	460 MW Combustion Turbine		$79	
3	300 MW Posey *	($5)	$37	
4	100 MW Warrick *	($2)	$10	
5	335 MW Solar PPA *	($6)	$28	
6	200 MW Wind *	($5)	$36	
7	Securitization	($56)	$23	
8	Subtotal	($217)	$213	
9	Net Cost in millions			($4)
	*REC Sale Savings			

	Day-One Monthly Bill Impact	Customers	4CP Allocations	Monthly Bill Impact 4CP
10	Residential	132,669	41%	($1)
11	Small General Service	10,118	2%	($1)
12	Demand General Service	8,204	28%	($10)
13	Off Season Service	742	2%	($9)
14	Large Power	117	26%	($700)
15	High Load Factor	2	1%	($1,300)

[1] Excludes temporary capacity purchases

High End Estimated Net Monthly Rate Impact by Customer Class
Generation Transition with Securitization & CTs[1]
With Net Savings from Culley 2, Warrick 4, AB Brown 1&2 Coal Units

Line	Description	Savings (Millions $)	Cost (Millions $)	Total (Millions $)
1	Expected O&M and Fuel Savings from C2, W4, ABB 1&2	($143)		
2	460 MW Combustion Turbine		$79	
3	300 MW Posey *	($5)	$37	
4	100 MW Warrick *	($2)	$10	
5	335 MW Solar PPA *	($6)	$28	
6	130 MW Solar Owned *	($2)	$18	
7	200 MW Wind *	($5)	$36	
8	150 MW Wind *	($4)	$32	
9	Securitization	($56)	$23	
10	Subtotal	($223)	$263	
11	Net Cost in millions			$40
	*REC Sale Savings			

	Day-One Monthly Bill Impact	Customers	4CP Allocations	Monthly Bill Impact 4CP
12	Residential	132,669	41%	$10
13	Small General Service	10,118	2%	$6
14	Demand General Service	8,204	28%	$112
15	Off Season Service	742	2%	$96
16	Large Power	117	26%	$7,500
17	High Load Factor	2	1%	$14,800

[1] Excludes temporary capacity purchases

Low End Estimated Net Monthly Rate Impact by Customer Class - Existing Allocations
Generation Transition with Securitization (CTs)
With Net Savings from Culley 2, Warrick 4, AB Brown 1&2 Coal Units

		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Line	Rate Schedule	Expected O&M and Fuel Savings from C2, W4, ABB1, and ABB2	Savings Per kWh (= A ÷ C)	2024 Budgeted Sales (kWh)	2024 Customers	Average Use Per Customer (AUPC) Per Month (kWh) (= C ÷ D ÷ 12)	Monthly C2, W4, ABB1, and ABB2 Bill Impact (= B * E * -1)	4 CP Allocations[2]	CT, Posey, & 200 MW Wind, Monthly Bill Amount (= (A9+A15+A17) * G ÷ C *E)	FAC Proxy Allocations[3] (= C ÷ C8)	Warrick & 335 MW Solar PPA Monthly Bill Amount (= (A11+A13) * I ÷ C * E)	Monthly Posey and 200 MW Wind RECs[4] (= (A10+A16) * G ÷ C * E * -1)	Monthly Warrick and 335 MW Solar PPA RECs[4] (=(A12+A14) * I ÷ C * E * -1)	Net Securitization Savings Estimate =(A18-A19)*(A ÷ A8)*-1	Securitization Estimate Monthly Bill Impact (=M ÷ C * E)	Monthly Net Bill Impact (= F + H + J + K + L + N)	Net Rate Impact ($ per kWh) (= O ÷ E)	Reference
1	Residential	$65,863,199	$ 0.04811	1,369,139,663	132,669	860	$ (41.37)	40.7467%	$ 38.84	26.4497%	$ 6.31	$ (4.71)	$ (1.27)	$ (14,939,561.10)	$ (9.38)	$ (11.58)	$(0.013)	
2	Small General Service	$2,774,336	$ 0.04270	64,974,487	10,118	535	$ (22.85)	1.8234%	$ 22.79	1.2552%	$ 3.93	$ (2.77)	$ (0.79)	$ (629,294.80)	$ (5.18)	$ (4.87)	$(0.009)	
3	Demand General Service	$43,183,320	$ 0.04100	1,053,191,507	8,204	10,698	$ (438.64)	27.9043%	$ 430.11	20.3461%	$ 78.55	$ (52.20)	$ (15.74)	$ (9,795,149.13)	$ (99.50)	$ (97.41)	$(0.009)	
4	Off Season Service	$3,380,058	$ 0.03768	89,713,357	742	10,076	$ (379.61)	2.1556%	$ 367.37	1.7331%	$ 73.98	$ (44.59)	$ (14.82)	$ (766,688.90)	$ (86.11)	$ (83.78)	$(0.008)	
5	Large Power	$25,785,754	$ 0.01157	2,228,821,103	117	1,587,479	$ (18,365.92)	26.4753%	$ 28,614.98	43.0575%	$ 11,655.87	$ (3,472.91)	$ (2,335.10)	$ (5,848,908.96)	$ (4,165.89)	$ 11,931.03	$ 0.008	
6	High Load Factor	$1,538,842	$ 0.00440	349,449,882	2	14,560,412	$ (64,118.41)	0.8947%	$ 56,569.96	6.7508%	$ 106,908.00	$ (6,865.71)	$ (21,417.60)	$ (349,051.10)	$ (14,543.80)	$ 56,532.44	$ 0.004	
7	Street Lighting	$0	$ -	21,096,985	42	41,859	$ -	0.0000%	$ -	0.4076%	$ 307.35	$ -	$ (61.57)	$ -		$ 245.77	$ 0.006	
8	Total	$142,525,510		5,176,386,984	151,894													
9	Posey Year 1 Estimated Cost	$ 37,172,210																Posey Solar, Line 6
10	Posey Year 1 Estimated REC Sales	$ 5,476,752																Posey Solar, Line 3 * 8 ÷ 1,000
11	Warrick Year 1 Estimated Cost	$ 9,702,116																Warrick County Solar, Line 8
12	Warrick Year 1 Estimated REC Sales	$ 1,744,992																Warrick County Solar, Line 3 * 8 ÷ 1,000
13	New Solar PPA Year 1 Estimated Cost	$ 28,304,855																335 MW Solar PPA Estimate, Line 8
14	New Solar Year 1 Estimated REC Sales	$ 5,869,200																335 MW Solar PPA Estimate, Line 3 * 8 ÷ 1,000
15	200 MW Wind Year 1 Estimated Cost	$ 35,713,256																200 MW Wind Estimate, Line 14
16	Wind Year 1 Estimated REC Sales	$ 5,326,080																200 MW Wind Estimate, Line 11 * 8
17	CTs Year 1 Estimated Cost	$ 78,861,370																CT Estimate, Line 13
18	Existing Return On and Depreciation Expense Removal	$ 55,823,485																Summary, Line 13
19	Securitization Cost	$ 23,494,831																Confidential Securitization, Line 213
20	Bill DECREASE (Line 8-9+10-11+12-13+14-15+16-17+18-19)	$ (3,517,380)																

[1] Savings based on 43839 Cost of Service Study (COSS) updated for amortization expirations and federal tax law changes, projected fixed and variable O&M and fuel savings
[2] Residential includes RS (40.6160%) and B (0.1307%) rate schedules. LP excludes special contracts and includes LP (24.6258%) and BAMP-Auxiliary (1.8495%) rate schedules, pursuant to Cause No. 43354 MCRA 21 S1 Settlement Agreement
[3] Allocation estimates for FAC based on 2024 budgeted sales. Does not consider impact of line losses, special contracts, or other considerations within the FAC calculation
[4] Estimated Renewable Energy Credit (REC) price is $8 per MWh, based on market information

High End Estimated Net Monthly Rate Impact by Customer Class - Existing Allocations
Generation Transition with Securitization (CTs)
With Net Savings from Culley 2, Warrick 4, AB Brown 1&2 Coal Units

Line	Rate Schedule	A Expected O&M and Fuel Savings from C2, W4, ABB1, and ABB2	B Savings Per kWh (= A ÷ C)	C 2024 Budgeted Sales (kWh)	D 2024 Customers	E Average Use Per Customer (AUPC) Per Month (kWh) (= C ÷ D ÷ 12)	F Monthly C2, W4, ABB1, and ABB2 Bill Impact (= B * E * -1)	G 4 CP Allocations[2]	H CT, Posey, 200 MW Wind, 150 MW Wind, and 130 MW Owned Solar Monthly Bill Amount (= (A9+A15+A17+A18) * G ÷ C *E)	I FAC Proxy Allocations[3] (= C ÷ C8)	J Warrick & 335 MW Solar PPA Monthly Bill Amount (= (A11+A13) * I ÷ C * E)	K Monthly Posey and Wind RECs[4] (= (A10+A16+A21) * G ÷ C * E * -1)	L Monthly Warrick and New Solar RECs[4] (=(A12+A14) * I ÷ C * E * -1)	M Net Securitization Savings Estimate =(A22-A23)*(A ÷ A8)*-1	N Securitization Estimate Monthly Bill Impact =(M÷ C)*E	O Monthly Net Bill Impact (= F + H + J + K + L + N)	P Net Rate Impact ($ per kWh) (= O ÷ E)	Q Reference
1	Residential	$65,863,199	$ 0.04811	1,369,139,663	132,669	860	$ (41.37)	40.7467%	$ 51.50	26.4497%	$ 6.31	$ (4.40)	$ (1.27)	$ (14,939,561.10)	$ (9.38)	$ 1.40	$ 0.002	
2	Small General Service	$2,774,336	$ 0.04270	64,974,487	10,118	535	$ (22.85)	1.8234%	$ 30.22	1.2552%	$ 3.93	$ (2.58)	$ (0.79)	$ (629,294.80)	$ (5.18)	$ 2.75	$ 0.005	
3	Demand General Service	$43,183,320	$ 0.04100	1,053,191,507	8,204	10,698	$ (438.64)	27.9043%	$ 570.38	20.3461%	$ 78.55	$ (48.69)	$ (15.74)	$ (9,795,149.13)	$ (99.50)	$ 46.36	$ 0.004	
4	Off Season Service	$3,380,058	$ 0.03768	89,713,357	742	10,076	$ (379.61)	2.1556%	$ 487.17	1.7331%	$ 73.98	$ (41.59)	$ (14.82)	$ (766,688.90)	$ (86.11)	$ 39.02	$ 0.004	
5	Large Power	$25,785,754	$ 0.01157	2,228,821,103	117	1,587,479	$(18,365.92)	26.4753%	$ 37,946.60	43.0575%	$ 11,655.87	$ (3,239.42)	$ (2,335.10)	$ (5,848,908.96)	$ (4,165.89)	$ 21,496.13	$ 0.014	
6	High Load Factor	$1,538,842	$ 0.00440	349,449,882	2	14,560,412	$(64,118.41)	0.8947%	$ 75,017.97	6.7508%	$ 106,908.00	$ (6,404.13)	$ (21,417.60)	$ (349,051.10)	$ (14,543.80)	$ 75,442.03	$ 0.005	
7	Street Lighting	$0	$ -	21,096,985	42	41,859	$ -	0.0000%	$ -	0.4076%	$ 307.35	$ -	$ (61.57)	$ -		$ 245.77	$ 0.006	
8	Total	$142,525,510		5,176,386,984	151,894													
9	Posey Year 1 Estimated Cost	$ 37,172,210																Posey Solar, Line 6
10	Posey Year 1 Estimated REC Sales	$ 5,476,752																Posey Solar, Line 3 * 8 ÷ 1,000
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15	200 MW Wind Year 1 Estimated Cost	$ 35,713,256																200 MW Wind Estimate, Line 14
16	200 MW Wind Year 1 Estimated REC Sales	$ 5,326,080																200 MW Wind Estimate, Line 11 * 8
17	CTs Year 1 Estimated Cost	$ 78,861,370																CT Estimate, Line 13
18	130 MW Owned Solar Year 1 Estimated Cost	$ 17,523,165																130 MW Owned Solar Estimate, Line 6
19	130 MW Owned Solar Year 1 Estimated REC Sales	$ 2,381,459																130 MW Owned Solar Estimate, Line 3 * 8 ÷ 1,000
20	150 MW Wind Year 1 Estimated Cost	$ 31,962,952																150 MW Wind Estimate, Line 14
21	150 Wind Year 1 Estimated REC Sales	$ 3,994,560																150 MW Wind 1 Estimate, Line 11 * 8 ÷ 1,000
22	Existing Return On and Depreciation Expense Removal	$ 55,823,485																Summary, Line 13
23	Securitization Cost	$ 23,494,831																Confidential Securitization, Line 213
24	Bill INCREASE (Line 8-9+10-11+12-13+14-15+16-17+18-19)	$ 39,592,718																

[1] Savings based on 43839 Cost of Service Study (COSS) updated for amortization expirations and federal tax law changes, projected fixed and variable O&M and fuel savings
[2] Residential includes RS (40.6160%) and B (0.1307%) rate schedules. LP excludes special contracts and includes LP (24.6258%) and BAMP-Auxiliary (1.8495%) rate schedules, pursuant to Cause No. 43354 MCRA 21 S1 Settlement Agreement
[3] Allocation estimates for FAC based on 2024 budgeted sales. Does not consider impact of line losses, special contracts, or other considerations within the FAC calculation
[4] Estimated Renewable Energy Credit (REC) price is $8 per MWh, based on market information

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY dba CENTERPOINT ENERGY INDIANA SOUTH

2 Combustion Turbine Project
Estimated Year 1 Impact
on the Bill of a Residential Standard Customer

Line	Description		Estimated Bill Impact
1	Residential Sales - kWh		1,369,139,663
2	Residential Allocation (Capital)		40.6160%
3	Standard Residential AUPC		1,000
4	Actual AUPC		860
5	Gross Plant Investment	$	323,000,000
6	Pre-Tax Rate of Return		7.53%
7	Pre-Tax Return on Investment (Line 5 x Line 6)	$	24,321,900
8	Depreciation Rate		3.44%
9	Annual Depreciation Expense (Line 5 x Line 8)	$	11,111,200
10	Other Annual O&M Expense - Fixed and Variable[1]	$	5,972,125
11	Cost of Gas[2]	$	8,988,996
12	Cost of Firm Gas Service	$	27,300,000
13	Annual Revenue Requirement with IURT (Sum of Lines 7, 9, 10, 11, & 12 ÷ .9852)	$	78,861,370
14	Residential Rate per kWh (Line 14 x Line 12 ÷ Line 1)	$	0.023394
15	Residential Bill (Standard AUPC assumption 1,000 kWh)	$	23.39
16	Residential Bill (Actual AUPC 860 KWh)	$	20.12

[1] Assumes IRP cost estimate with 150 starts per units

[2] Assumes IRP gas cost and ~6% annual capacity factor in the first year of operation. Reference case annual capacity factor over the IRP time period is ~2%

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a CENTERPOINT ENERGY INDIANA SOUTH
(CENTERPOINT INDIANA SOUTH)

IURC CAUSE NO. 45564

DIRECT TESTIMONY
OF
NELSON BACALAO
PRINCIPAL CONSULTANT, SIEMENS PTI

ON

INTEGRATED RESOURCE PLAN PROCESS AND RESULTS

SPONSORING PETITIONER'S EXHIBIT NO. 6

ATTACHMENT NB-1

DIRECT TESTIMONY OF NELSON BACALAO

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Nelson Bacalao. My business address is 703 Detering St. Apt A Houston TX 77007.

Q. By whom are you employed and in what capacity?

A. I am a Principal Consultant at Siemens PTI ("Siemens PTI").

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting testimony on behalf of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("Petitioner", "CenterPoint Indiana South", "CEI South", or" Company").

Q. Have you previously testified before the Indiana Utility Regulatory Commission (the "Commission") or other public utility commission?

A. Yes, I testified before the Puerto Rico Energy Bureau First and Second IRP, Cases No. CEPR-AP-2015-0002 and CEPR-AP-2018-0001, on behalf of the Puerto Rico Electric Power Authority ("PREPA").

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support CenterPoint Indiana South's 2019/2020 Integrated Resource Plan ("2019/2020 IRP") process, as well as Petitioner's Generation Transition Plan, and address issues related to the cost estimates and assumptions associated with the new Combustion Turbines additions proposed in the Preferred Portfolio from the 2019/2020 IRP.

Q. Please summarize your education and experience relevant to your testimony in this case.

A. My relevant education and experience are discussed within my resume, a copy of which is attached as Petitioner's Exhibit No. 6, Attachment NB-1. I hold a Ph. D. in Electrical

Engineering from the University of British Columbia, Vancouver, BC, Canada, earned in 1987. I hold a Master Engineering (Electrical) degree from Rensselaer Polytechnic Institute in Troy, NY, earned in 1980. I hold an Electrical Engineer degree from Universidad Simon Bolivar in Caracas, Venezuela, earned in 1979. I have been employed by Siemens PTI since January 2006. I am a Principal Consultant based in Houston and my professional experience covers technical and strategic consulting services to utilities, governments, regulators, independent project developers, and the financial community, in domestic as well as international assignments. My work has been centered on power system planning with emphasis on Integrated Resource Planning, integration of renewable generation and the impact on transmission and distribution systems.

Q. Please summarize the history of Siemens PTI and your consulting relationship with CenterPoint Indiana South.

A. Siemens PTI is the consulting unit of Siemens Industry and has been in the power system consulting business since 1969 under the name of Power Technologies Inc. PTI became part of Siemens in January 2006. Siemens PTI's continued growth led to the acquisition of Pace Global Energy Services, to strengthen our capabilities in market analytics and general Energy Business Advisory. Siemens PTI provided support for Petitioner's 2019/2020 IRP and continues to be engaged to provide testimony support. With Siemens PTI, I have provided consulting services to CenterPoint Energy Houston Electric[1] on the areas of interconnection studies and North American Electric Reliability Corporation ("NERC") Compliance (CIP-14).

Q. Please summarize Siemens PTI's role in the 2019/2020 CenterPoint IRP process.

A. Siemens PTI contributed to Petitioner's 2019/2020 IRP process in several key areas. The main contribution was the management and development of the IRP modeling (including some input development), strategic consulting, participation in the stakeholder process, and scorecard development.

[1] CenterPoint Energy Houston Electric is a subsidiary of the same parent company (CenterPoint Energy, Inc.) as CenterPoint Indiana South.

Q. Please describe Siemens PTI's recent experience and expertise in structuring and leading integrated resource planning for utilities such as CenterPoint Indiana South.

A. Siemens PTI is a leading consultant for integrated resource planning, with extensive experience in structuring and facilitating IRPs for utilities throughout the United Stated and Caribbean. The following list represents a selection of recent clients that have engaged Siemens PTI to contribute to their IRP processes: Orlando Utilities Commission (FL), Peninsula Clean Energy (CA), East Bay Community Energy (CA), San Jose Clean Energy (CA), Clean Power Alliance of Southern California (CA), Clean Power San Francisco (CA), Memphis Light Gas and Water (TN), and other utilities and load servicing entities with whom we are under confidentiality agreements in Missouri and other states. Siemens PTI also assisted Petitioner in its 2014 and 2016 IRP processes and is currently assisting another Indiana electric utility with its IRP, currently in the stakeholder process.

Q. What have you done in preparation to develop opinions regarding the 2019/2020 IRP and CenterPoint Indiana South generation plan?

A. I did not have a direct role in preparing the 2019/2020 IRP; hence, I am bringing my independent view of how the process was conducted. In order to conduct my review, I read the IRP reports, and reviewed the various stakeholders' filings and IRP workpapers.

II. MODELING, GENERATION PLANNING, AND SCORECARD

Q. Have you reviewed the documentation filed by CenterPoint Indiana South on the IRP and the corresponding workpapers and models?

A. Yes, I have. The volume of information is quite substantial, and I have sought to became familiar with the rationale used by CEI South to identify the Preferred Portfolio with the support of my colleagues .

Q. Are you aware that the Preferred Portfolio (High Technology) includes the installation of two gas turbines rated 236 MW each?

A. Yes, I am aware of that recommendation of the Preferred Portfolio and reviewed the reasons behind the recommendation.

Q. Describe your view on the approach used in the IRP for selecting the Preferred Portfolio's two gas turbines.

A. In its Order in Cause No. 45052, the Commission explained that long-term risk is an important factor to be considered in the context of generation proposals: "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." Cause No. 45052 Order, p. 20. Petitioner's Witness Steven C. Greenley further addresses this concept in his testimony. I would describe this as the risk of buyer's remorse: the risk that a decision is made today which the Company and stakeholders later regret. Thus, the analysis should provide the decision makers information on the performance that these decisions have under future states of the world and identify which decisions are most likely to perform best and minimize the chances of buyer's remorse or regret.

The approach that Siemens PTI uses to analyze portfolios is to analyze in detail those portfolios that perform best across the relevant metrics and make a recommendation by identifying the portfolio that minimizes the risk. To achieve this, my approach is to review portfolio decisions and identify those that minimize the impact of having it wrong – the impact of an asset becoming "uneconomic" in the Commission's words. I sometimes call this identifying the risk and impact that a decision will later be regretted by the utility, and hence its customers and stakeholders. Based on my review of the analysis done by CEI South, I find it consistent with the approach above and I think the decision to build the two combustion turbines ("CTs") is consistent with the public convenience and necessity in part because it fulfills the Company's needs for capacity and peaking energy with generation resources that the Company and its stakeholders are unlikely to regret.

Q. Can you please elaborate?

A. We are entering a period of tremendous transition in the power generation industry. For decades, the industry has primarily relied upon fossil fuel for its generation resources, more specifically coal. In the recent past and over the coming years, much of that coal-fired generation will be retired as the industry transitions to portfolios consisting much more extensively of renewable resources. Our grid cannot switch entirely to renewable resources, however, because renewables must be supported by dispatchable power. This is not simply because of the intermittency of renewables but also is a function of the contribution that they provide to support the system peak and the required reserves. In the wintertime, with shorter days, there will not be sunlight during the evening peak and even for summer, as more photovoltaic generation is added to the system, net peak displaces to the evening, reducing the contribution of the renewable. So, the challenge becomes identifying the proper mix of renewable resources and dispatchable resources. Dispatchable resources will be more susceptible to regret if gas prices rise; renewable resources will be more susceptible to regret if capacity prices rise. A portfolio that mitigates the risk and impact of regret is a portfolio that navigates well through these often-competing risks. Let's take one risk factor at a time and assess how this decision plays out for the Preferred Portfolio with the CTs[2].

Q. How do the portfolios compare when considering the risk of gas price volatility?

A. The CTs' role in a portfolio is to provide peaking power and reserves. The peaking power functionally refers to the dispatch of generation during those peak load hours when there is insufficient base load generation or renewables in the system to supply the load. This typically occurs in relatively few hours per year. The reserve functionality refers to standing-by to supply the load in case a generation outage occurs. This all means that the CTs, as opposed to other base load generation (e.g., the Combined Cycle generators or Steam Turbine generation), run and burn gas only for a few hours during the year and hence are much less affected by gas price fluctuations. In the specific case of the Preferred Portfolio, the CTs have a very low capacity factor[3], an average of approximately 3% for the planning period for Reference Case conditions, which is much lower than those typical for base load generation (60% or higher). Another way of seeing this is considering that the cost of fuel for peakers typically represents about 2% of the net present value of the revenue requirements ("NPVRR"), thus the gas price may double and only have an effect of 2% increase in the NPVRR.

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[2] These are the other portfolios that had the lower net present value of the revenue requirement ("NPVRR") and performed well across a wide range of factors: Reference Case, Renewable + Flexible Gas, and Renewable 2030 (See Figure 8-8 of the 2019/2020 IRP Volume 1 pg. 251).
[3] Capacity Factor = Energy Produced / (Installed Capacity x hours of the year).

Another aspect to consider is that CTs can be turned on and off with great flexibility which makes them a good companion to intermittent renewables. In contrast, steam gas generation as would be the case of a converted A.B. Brown to gas is much less flexible and can be locked to run at minimum levels as it cannot be turned off and on as frequently. As a reference, the table below shows the NPVRR of the ABB1 + ABB 2 Gas Conversion scenario under reference condition and the present value of the fuel cost for the converted ABB1 and ABB2 and we see that represents 3.6~~5~~% of the NPVRR. On the other hand, for the Preferred Portfolio (i.e., the High Technology Portfolio), the present value of the fuel costs represents 2%, 44% less. We also note in this table that with the exception of the Renewable 2030 Portfolio that stops using gas by 2030, the fuel cost of the Preferred Portfolio as a percentage of their NPVRR is the lowest among the least cost portfolios.

Table 1[4]

	NPVRR M$	**NPV NG Costs for Peaking Units M$**	**NG Cost as % NPVRR**
Bridge ABB1 + ABB2	$2,837 ~~$2,887~~	$101.92	3.6%~~3.5%~~
Preferred Portfolio – High Technology	$2,679	$52.76	2.0%
Renewables 2030	$2,678	$37.78	1.4%
Reference Case	$2,616	$65.47	2.5%
Renewables + Flexible Gas	$2,600	$55.95	2.2%

Q. How does the risk of higher capacity prices affect the portfolios?

A. As I explained previously, those portfolios that are more reliant on dispatchable power face a higher risk from gas price volatility; however, those portfolios more reliant on renewable resources will face a higher risk from capacity price volatility. CenterPoint Indiana South as a Midcontinent Independent System Operator ("MISO") member must meet the MISO Planning Reserve Margin Requirement ("PRMR"). In the IRP, a Planning Reserve Margin based on Unforced Capacity ("UCAP PRMR") requirement of 8.9% of the coincident peak load[5] was used, which is in line with MISO's requirements[6] and must be met by the capacity contributions of the resources in the portfolio or by market capacity

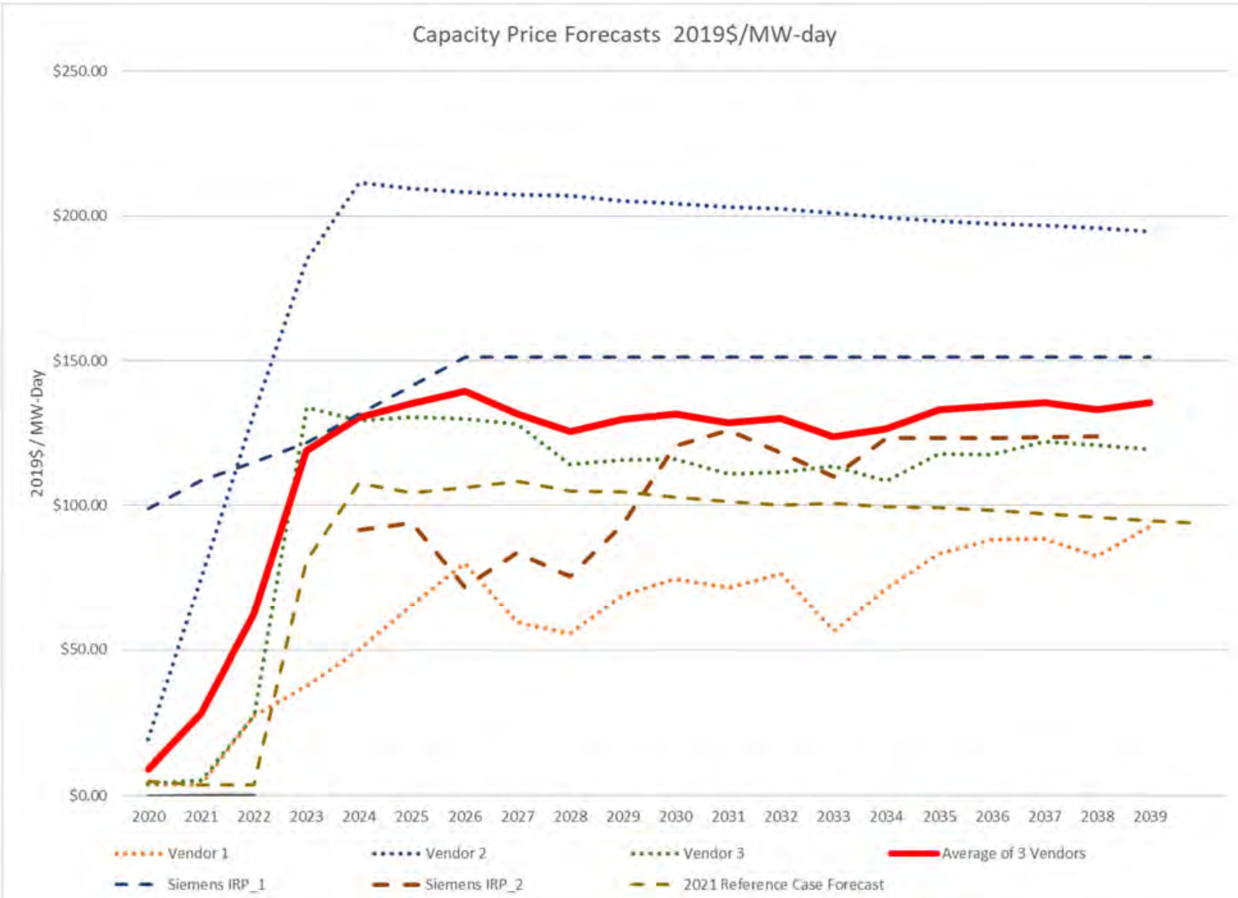
[4] Includes updates to capture fixed cost update to conversion portfolio (Bridge ABB1 + ABB2).
[5] This is CenterPoint Indiana South's load at the time of MISO's system wide peak.
[6] 2019/2020 IRP Volume 1, pg. 160 and MISO's Planning Year 2020-2021 Loss of Load Expectation Study Report.

purchases. Each of the resources owned or contracted by CenterPoint Indiana South contributes to meet the PRMR requirement and gas generators like the CTs contribute between 90% to 95% of its installed capacity to meet it[7]. Any shortfall must be procured in MISO's Capacity Auction, whose prices can be very volatile and difficult to predict as they depend on a tight balance between offer and supply. This can be observed by noting the widespread in the forecast as shown Figure 7-7 of the IRP Volume 1 and reproduced below, where we see that the high forecast is more than double the low forecast and gets close the MISO's ceiling equal to the cost of a new entry ("CONE") to provide the reserves ($257 MW/day).

Another aspect to consider is that in the below while the forecast for Vendor 1, which is PACE (a Siemens Company at the time), is the lowest, forecasts change as vendors have more information and consider the situations of the companies that will have to go to market to secure capacity (either spot or bilateral). In the figure I also added Siemens current Reference Capacity Forecast for MISO and the capacity forecast used for two IRPs in MISO that considered the particularities of the utilities. As noted, all updated forecasts are above those of Vendor 1 (PACE).

[7] Table 8-6 of CEI South IRP Volume 1, pg. 249.

Figure 1



Moreover, there are various risk factors that seem to indicate the potential for higher prices. The Local Resource Zone ("LRZ") 6, where CenterPoint Indiana South is located, does not have enough local resources to meet its Local Reliability Requirements ("LRR") and is dependent on imports from other MISO LRZs[8]. This makes Zone 6 dependent on the generation surplus in other zones, that may or may not materialize, adding practical deliverability risks and price risks. The capacity shortfall in MISO and specifically in Zone 6 is only expected to grow in the coming years, as noted in Petitioner's Witness F. Shane Bradford's testimony.

[8] Figure 5.9 of 2019/2020 IRP Volume 1 pg. 144 and Table 6-1 to 6-3 of MISO's Planning Year 2020-2021 Loss of Load Expectation Study Report.

The more heavily reliant a portfolio is on renewable resources, the greater the exposure to capacity price volatility risk. As more solar generation enters the market, the system resource adequacy determinations are likely to evolve from summer peaking to summer/winter peaking or a four seasonal construct as currently considered by MISO[9]. As I noted previously, there is a significant difference in the contribution of solar generation to meet the summer peak versus the winter peak. This is largely a function of the shorter days and the occurrence of the peak after dark. In the summer, much of the evening peak occurs while the sun is still shining; in winter, the evening peak occurs after dark. Additionally, as solar generation penetration increases, the summer peak contribution is also affected. As more renewable enter the system, the peak of the net load[10], which accounts for the reduction of renewable generation, displaces to later in the day when renewable resources also contribute less. This effect is captured in the industry with what is called the Effective Load Carrying Capability ("ELCC"), which is a measure of how much a resource can be depended on to supply the peak. For fossil fuel generation. this value is quite high — typically over 90% of the installed capacity; for solar it is currently 50% in MISO of the installed capacity for summer, and it reduces to only 5% for winter, as explained above. Both values for solar will reduce further as penetration increases. For wind generation, the ELCC is more uniform during the year and in the order of 15% for summer, spring, and fall, and 20% for winter.

As can be appreciated, as more and more fossil fuel generation retires and is replaced with renewables, the need for dispatchable power becomes more pronounced. A construct requiring meeting a winter PRMR requirement would have very low contribution of solar and would have to be met with thermal resources, wind resources, and storage[11]. As we have more and more solar penetration into the overall grid portfolio, this will drive up the cost of capacity in the market. The more reliant a portfolio is on renewables, the more it

[9] RAN Reliability Requirements and Sub-annual Construct (misoenergy.org): https://cdn.misoenergy.org/20210203%20RASC%20Item%2004a%20Subannual%20Construct%20Presentation%20(RASC010,%20011,%20012)517859.pdf.
[10] The net load is the effective load of the system accounting for the effects of the renewable generation output.
[11] See Figure 8-6 and 8-7 of the 2019/2020 IRP Volume 1 pg. 249 for ELCC of thermal, wind and solar and its projections.

will rely on capacity purchases. If capacity prices rise more than forecasted, it increases the risk that a particular decision will be regretted.

The Preferred Portfolio with the two CTs is much less susceptive to the impact on changes in capacity prices as it has the lowest forecasted amount of capacity purchases of the four least cost portfolios[12] and hence it has the lowest exposure to this risk. The table below shows for the four least cost portfolios and for the case where A.B. Brown is converted to gas, the average market capacity purchases, the present value of the associated cost and how much it represents as a percentage of the Net Present Value for the portfolio revenue requirements ("NPVRR"). We observe that the Renewable 2030 has the greatest exposure followed by the Reference Case and Renewable + Flexible Gas, A.B. Brown Conversion ((Bridge ABB1 and Bridge ABB1 +ABB2) and the preferred portfolio (High Technology) has the least exposure.

Table 2[13]

Scenario	Average Capacity Purchases (2020-2039) MW	NPV of Capacity Purchases Cost M$	% NPVRR	NPVRR M$
Renewables 2030	137~~152~~	53.51~~62.05~~	2.0%~~2.3%~~	2,678
Reference Case	111~~124~~	39.78~~46.12~~	1.5%~~1.8%~~	2,616
Renewables + Flexible Gas	109~~121~~	39.18~~45.43~~	1.5%~~1.7%~~	2,600
Bridge ABB1	108	39.70	1.5%	2,683
Bridge ABB1 + ABB2	46~~207~~	11.97~~50.97~~	0.4%~~1.8%~~	2,837
Preferred Portfolio- High Technology	5~~33~~	2.59~~2.97~~	0.1%~~0.1%~~	2,679

Another aspect to consider is that the ELCC of storage declines as penetration increases[14] and the Preferred Portfolio would be only marginally affected by a reduction of ELCC of

[11] Renewable + Flexible Gas

[13] Includes updates to capture fixed cost update to conversion portfolios (Bridge ABB1 and Bridge ABB1 + ABB2). Also includes updates to capacity purchases and capacity purchase values.

[14] Storage was conservatively modeled in the IRP with a constant ELCC of 95%, however this value is likely to decline as more storage is added to system. For example, on a recent study for NY we are using 75% for a 4 hours battery as recommended by NYSO for penetrations greater than 1000 MW (see Expanding Cap. Eligibility:

storage as it only has 50 MW installed in 2039, which is not the case for the Renewable 2030 that has 360 MW of storage by 2031. Simply put, as the level of storage increases in the MISO Market, the level of accredited capacity would go down. It is the same phenomenon discussed regarding solar resources. This risk was not considered within the IRP but is an important factor to consider when evaluating a portfolio that relies heavily on storage.

Q. What conclusions do you derive from the above?

A. I conclude that the Preferred Portfolio with two CTs has very low exposure to the risk of high fuel prices while providing almost full protection to the risk of high capacity prices. The Preferred Portfolio has nearly the least exposure when considering gas price risk, with only Renewables 2030 being less exposed. On the capacity side, the Preferred Portfolio has the lowest risk of exposure ~~and by a large margin~~. Notably, the Renewables 2030 is most exposed on the capacity side. The Preferred Portfolio navigates these two competing variables very well and better than the other portfolios. In other words, compared to other portfolios, the effects of being wrong and regretting the decision are less pronounced.

Q. How does the possibility of battery storage affect the analysis?

A. Storage is a useful tool that can help address solar's inherent incapability to meet the system peaks and shift energy to those times when the sun is not shining. To address whether battery storage would have been a more economical solution than constructing two CTs, CenterPoint Indiana South conducted a sensitivity analysis where the CTs were replaced by storage that would provide similar amounts of reserve as the CTs. The storage was selected from a bid received on the All source RFP[15] and consisted of eight modules with 76.2 MW of three-hour storage each, totaling 609.6 MW. With expected ELCC of

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https://www.nyiso.com/documents/20142/5375692/Expanding%20Capacity%20Eligibility%20030719.pdf/19c4ea0d-4827-2e7e-3c32-cf7e36e6e34a) and in an study for CAISO a value as low as 54% was identified for high levels of storage penetration (see Energy Storage Capacity Value on the CAISO System: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/2019-20%20IRP%20Astrape%20Battery%20ELCC%20Analysis.pdf).

[15] See Section 6.1.1 of the 2019/2020 IRP Volume 1 pg. 149.

71%, the resulting capacity value of 434.3 MW is slightly higher than the capacity value of the two CTs (409 MW).

Q. Have you reviewed that sensitivity analysis?

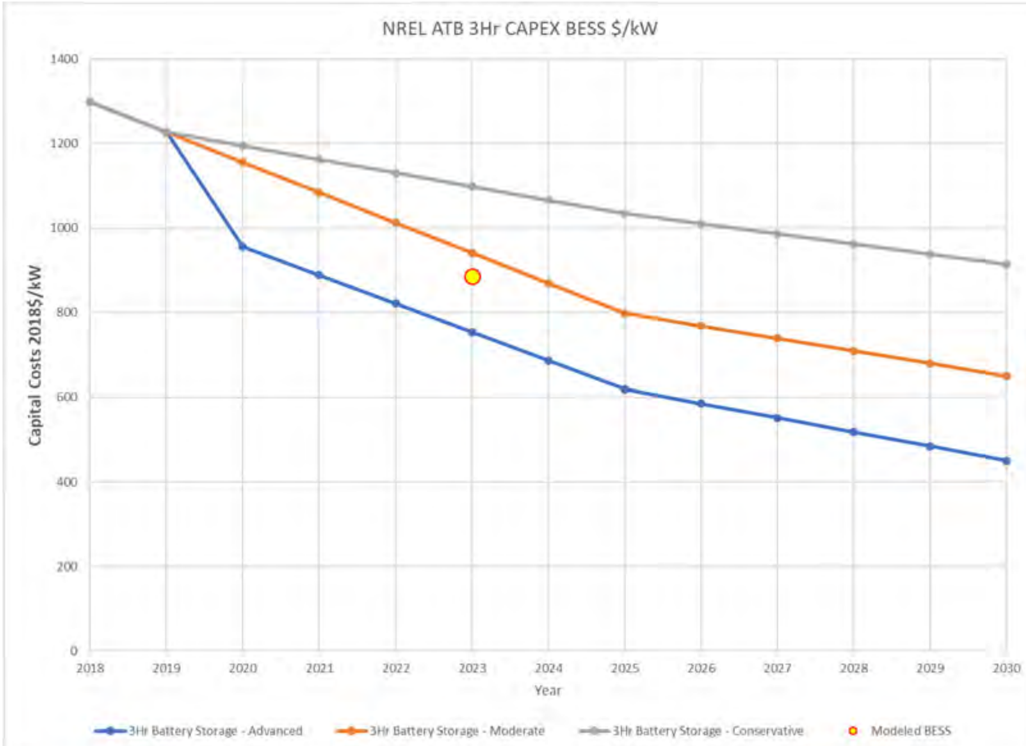
A. Yes. I reviewed the sensitivity calculations and identified that the building storage resulted in an increase of 5% on the NPVRR of the portfolio. This was driven by the higher capital and fixed O&M costs of the storage that are approximately 54% higher than corresponding costs of the CTs and result in an 17% increase in the overall capital and fixed O&M costs component of the NPVRR. This increase in cost is partly compensated by a reduction in fuel costs (5% reduction) and emissions cost (2% reduction).

Q. Are the prices for storage assumed in CenterPoint Indiana South's sensitivity analysis reasonable?

A. Yes. First, these are actual prices that were submitted in response to an actual RFP. But given the importance of the Storage PPA costs in driving the results above, I further compared this cost with the 2020 NREL's ATB forecast[16]. To get a comparable capital cost in $/kW, I subtracted from the PPA yearly payments the expected component for Fixed O&M costs (using the ATB forecast) and then determined the implied capital using the same discount rate used in the IRP with a 15 year life. I further considered that CenterPoint Indiana South would have to enter this contract approximately two years ahead of the in-service date of the project (i.e., 2023). The figure below shows the result of the analysis where we note that the cost is below the expected trend (Moderate) and somewhat higher than the minimum expected costs (Advanced), thus confirming the adequacy of the values used in Petitioner's 2019/2020 IRP. In short, I agree with the conclusion that additional storage will be more costly than the two CTs and attempting to replace one or both CTs with storage would be an uneconomic decision.

[16] https://atb.nrel.gov/electricity/2020/data.php.

Figure 2



Q. Are there other issues that should be considered besides economics when evaluating storage as a potential alternative?

A. Yes. As discussed earlier, the ELCC of storage may not be constant over time and as the penetration increases, it could decrease and possibly significantly as identified in the California Independent System Operator (CALISO) study and in the New York Independent System Operator (NYISO) studies (see footnote 14~~12~~ *supra*). Moreover, the storage considered was three hours duration and any real-life requirement with longer duration requirements could not be met. This is not the case with the CTs that can be in service for extended periods of time.

In summary, I think that the selection of battery energy storage in lieu of the CTs is not a robust solution and there is greater risk that it will result in higher costs and reduced services to CEI South's customers.

I think this summarizes well why I am of the opinion that CenterPoint Indiana South's decision to build the two CTs is a prudent decision for CenterPoint Indiana South and its customers and is in the public interest.

Q. Can you describe the Balanced Scorecard Methodology used in CenterPoint Indiana South's IRP?

A. The Balanced Scorecard is a method to present the results of an otherwise complex analysis effectively and concisely. Across the top are the key objectives to be assessed and this includes affordability typically measured by the NPVRR; environmental factors for example CO_2 emissions minimization; and risk factors such as risk of the NPVRR being higher than expected, or overreliance on an energy and capacity market that can be volatile. There can be other factors in the Balanced Scorecard, and I understand that the factors used by CenterPoint Indiana South were vetted via an extensive stakeholder process.

In the scorecard, each line contains the results for different portfolios allowing comparison.

The scorecard can be based on deterministic results, but in most advanced procedures the results of the Monte Carlo stochastic simulations are used. This was the case in CenterPoint Indiana South's IRP, which allowed, for example, to show the cost uncertainty by looking at the 95th percentile (i.e., the cost or value that would be exceeded only 5% of the time) across 200 iterations[17].

I have used the Balanced Scorecard in multiple assessments and in my opinion, it is a powerful tool to visualize the performance of multiple portfolios at a glance. The scorecard typically uses shades of the color green to depict favorable outcome and by inspection it is relatively easy to identify the best performing portfolios, allowing the identification of what is sometimes called the decision set, i.e., those portfolios that behave best in

[17] The 95th percentile is the value that is exceeded only 5% of the time and the greater the difference of this value to the mean is indication of the sensitivity of the portfolio to one or more uncertainties. CenterPoint Indiana South considered the following variable uncertain (stochastics); Load (energy and peak), natural gas (high uncertainty variable), coal, CO_2 emissions costs, capital costs for solar, wind, BESS, CCGTs and CTs.

comparison with the rest and are likely to contain the preferred portfolio and should be studied closely[18]. In the case of CenterPoint Indiana South's IRP, the Reference Case, the Renewable + Flexible Gas, the Renewable 2030 and the High Technology are clearly members of this decision set[19].

Q. Is the Monte Carlo 95th percentile approach the only way that cost risk can be analyzed?

A. No, there are other ways and I also looked at them to conclude that CenterPoint Indiana South's proposal to build the two CTs is prudent.

First, I look at how the different Portfolios NPVRR changes when subjected to different "states of the world" as described in the Scenarios that CenterPoint Indiana South considered[20]. For each of those scenarios, there is always a Portfolio that performs best (i.e., has the lowest NPVRR and performed well across other metrics) and would be the preferred decision if we had perfect foresight; this is sometimes called the No-Regret Portfolio for the given state of the world. Then I compare the other Portfolios under this state of the world (or future) and assess the difference with respect of the No Regret Portfolio and the difference is the degree of "Regret". With this approach we can factor the degree that different Portfolios benefit from a favorable outcome (e.g., a portfolio that could benefit more from a reduction in capital costs of renewable and storage than others)[21] and by how much they are shielded from adverse outcomes.

Using the results reported in in the IRP, I determined the Regret as defined above and calculated the simple average of the regret across the scenarios considered. Below I show the results of this assessment. This is a simple average of the deltas from the lowest NPVRR under the five different scenarios evaluated in the IRP. In other words, this

[18] See for example the MLGW IRP (http://www.mlgw.com/images/content/files/pdf/MLGW-IRP-Final-Report_Siemens-PTI_R108-20.pdf) Exhibit 10 and subsequent analysis of Portfolios 5, 9 and 10 together with the TVA option that were included in the decision set.
[19] Figure 8-8 of Volume I of the 2019/2020 IRP.
[20] See Figure 2.5 of the 2019/2020 IRP pg. 94.
[21] The convenience of assessing the upside of Portfolios was also expressed in the Director's report where it indicates that "[CenterPoint Indiana South] uses the 95th percentile as the metric for cost uncertainty. This is reasonable but it ignores the uncertainty around the potential for lower-than-expected cost. It is possible that a portfolio has more downside cost benefit than other portfolios, but this was not considered by [CenterPoint Indiana South]."

analysis is focused purely on NPVRR, and each of the various scenarios are equally rated. For example, it assumes the risk of the "Low Regulation" scenario is the same as the risk of the "High Regulation." We see below that Renewable + Flexible Gas has the lowest average regret, i.e., the chances of regretting the decision under an adverse future are lower. This Portfolio is followed by the Reference and then the Renewable 2030, the Bridge ABB1 and High Tech (Preferred Portfolio) that are ~~very~~ fairly close.

Table 3[22]

Regret assessment $000

Portfolio	Base Case	80% CO2 Reduction by 2050	High Technology	High Regulation	Low Regulation	Avg of Regret	Rank
P08 Renewables + Peak Gas	$ -	$ -	$ -	$ 123,706	$ 54,284	$ 35,598	1
Reference	$ 13,616	$ 26,834	$ 29,121	$ 191,970	$ -	$ 52,308	2
P09 Renewables 2030	$ 78,052	$ 55,902	$ 180,539	$ -	$ 239,400	$ 110,779	3
P10 - High Tech Portfolio	$ 85,673	$ 76,146	$ 64,432	$ 272,291	$ 69,030	$ 113,515	4
P04 Bridge ABB1	$ 126,615	$ 119,854	$ 148,333	$ 264,141	$ 121,692	$ 156,127	5
P06 Diverse Small CCGT	$ 162,751	$ 108,325	$ 140,662	$ 290,895	$ 140,938	$ 168,714	6
P02 - Bridge BAU- 2029	$ 234,682	$ 177,416	$ 254,987	$ 367,092	$ 25,078	$ 211,851	7
P03 Bridge ABB1 CCGT	$ 354,435	$ 291,880	$ 335,363	$ 463,461	$ 338,444	$ 356,717	9
P05 BridgeABB1 & ABB2	$ 287,200	$ 260,647	$ 298,705	$ 393,455	$ 268,644	$ 301,730	8
P01 BAU	$ 540,376	$ 430,441	$ 579,651	$ 653,076	$ 32,426	$ 447,194	10

Portfolio	Base Case	80% CO2 Reduction by 2050	High Technology	High Regulation	Low Regulation	Avg of Regret	Rank
P08 Renewables + Peak Gas	$ -	$ -	$ -	$ 123,706	$ 36,223	$ 31,986	1
Reference	$ 42,565	$ 44,895	$ 47,183	$ 210,031	$ -	$ 68,935	2
P09 Renewables 2030	$ 78,052	$ 55,902	$ 180,539	$ -	$ 221,339	$ 107,166	3
P04 Bridge ABB1	$ 101,080	$ 94,319	$ 122,798	$ 238,606	$ 78,096	$ 126,980	4
P10 - High Tech Portfolio	$ 103,734	$ 94,207	$ 82,493	$ 290,352	$ 69,030	$ 127,964	5
P06 Diverse Small CCGT	$ 180,813	$ 126,386	$ 158,724	$ 308,956	$ 140,938	$ 183,163	6
P02 - Bridge BAU- 2029	$ 252,743	$ 195,478	$ 273,049	$ 385,153	$ 25,078	$ 226,300	7
P03 Bridge ABB1 CCGT	$ 322,024	$ 259,469	$ 302,953	$ 431,050	$ 287,972	$ 320,694	9
P05 BridgeABB1 & ABB2	$ 254,789	$ 228,236	$ 266,294	$ 361,044	$ 218,172	$ 265,707	8
P01 BAU	$ 558,437	$ 448,502	$ 597,712	$ 671,137	$ 32,426	$ 461,643	10

[22] Includes updates to capture fixed cost update to conversion portfolios (P04 Bridge ABB1, P03 Bridge ABB1 CCGT, and P05 Bride ABB1 & ABB2).

Q. This analysis would seem to suggest the Renewable + Flexible Gas would have the least adverse impact if the decision were later regretted under this simple analysis. Is that the correct reading?

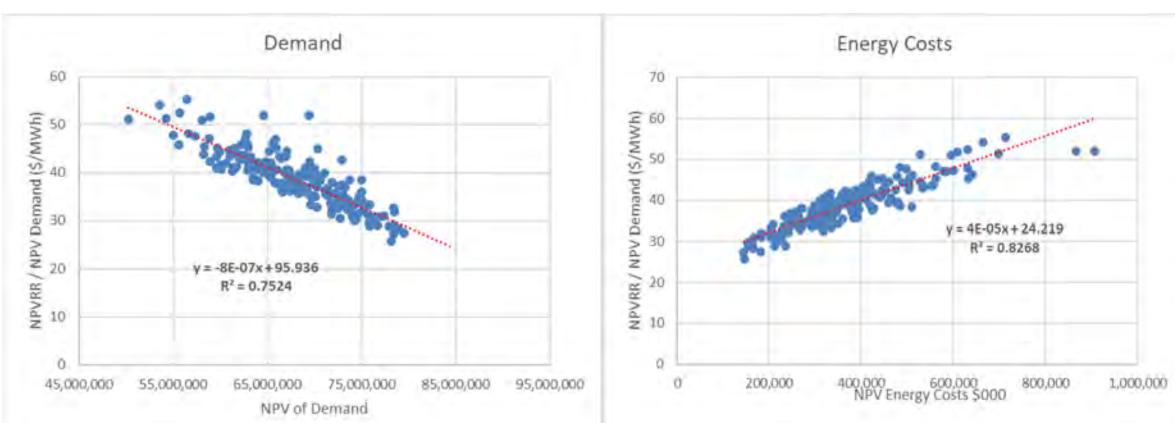
A. Yes, but with a qualification. Looking into this I noted that except for the Renewable 2030 and the Bridge ABB1, all the lowest regret Portfolios had a 236 MW CT built in 2024 and the Renewable + Flexible Gas had another built in 2033 versus the Preferred Portfolio that had it built together with the first unit. Thus, the option to delay the construction of the second turbine to 2033 in accordance with the Renewable + Flexible Gas should be considered. I investigated this and realized that first there are important construction efficiencies in building the two CTs together. As shown in Attachment 1.2 of Appendix 2 of the 2019/2020 IRP Volume 2, the cost of building the first unit (F Class Frame CT) is estimated to be in 2019$, $173 million and the cost of the second unit would be $121 million if they are developed at the same time, thus the construction efficiencies translate into $52 million savings. When I reviewed how the second unit was modeled, I noted that in both Portfolios, the fixed costs that include the capital recovery (amortization) were about the same, in fact the fixed cost for the second unit in the Renewable + Flexible Gas Portfolio was 98% of the cost for the same unit in the Preferred Portfolio. However, if the second unit were to be built later, these construction efficiencies would not be realized and the difference between the portfolios would be smaller. This benefit from construction efficiencies is not reflected in the table above. This difference alone, if included in the above analysis, would reduce the differences between the Preferred Portfolio and the Renewable + Flexible Gas to about 1.5%. Another aspect that would reduce the difference between the Portfolios is that Renewable + Flexible Gas Portfolio supplies a smaller load as it has 1% Energy Efficiency 2024 – 2026 compared with the High Technology (0.75%) and that it includes the retirement of F.B. Culley 3 in 2033 – 2034. If these additional factors were included in the High Technology case, the difference would be smaller and in the order of 1%.

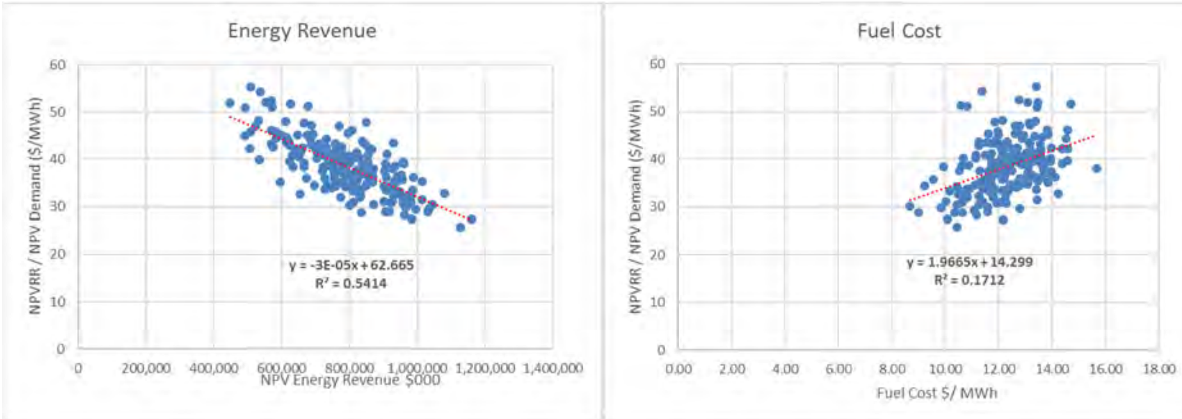
Building simultaneously the two turbines also minimizes the market capacity risks that as I elaborated earlier are substantial. It minimizes disturbance on the system as there would major work being carried out at A.B. Brown once, and it preserves the interconnection rights that CenterPoint Indiana South has at A.B. Brown. As I noted previously, the simple averaging I have presented assumes the risk of all different scenarios is equal. I will demonstrate some of these differences later in my testimony.

Q. Are there other approaches to evaluating the impact of the risk of choosing the wrong portfolio?

A. Yes. Another approach that I find useful is to identify the variables that most affect a Portfolio by reviewing the results of the Monte Carlo analysis. In this case, I look at how the average cost of the Portfolio under analysis changes as a function of uncertain variables. The Average Cost is determined by dividing the NPVRR by the NPV of the energy demand. I did this for the Preferred Portfolio and found that there is a clear correlation with the demand; higher demand to allocate the same fixed costs results in lower average costs per MWh, see first graph below that has on the X-axis the NPV of the Demand and the Y-axis the Average Cost. Also, there is a clear correlation with the Energy Cost (second graph) and with the Market Sales (third graph), as the first drives up the average cost up and second being an income rather than a cost. drives the average cost down. However, we note that changes in the fuel costs ($/MWh of NPV of Demand) are only weakly associated with changes in the Average Cost as can be noted in the fourth graph where we see a "blob" rather than a trend and we note the low R^2 (0.17) hence changes in fuel cost is not a significant risk for this Portfolio. I touched on this issue previously, when I evaluated the percentage of the NPVRR that was represented by fuel costs. But this analysis shows that the relatively limited risk of gas price volatility is fairly static: it correlates weakly with the portfolio costs.

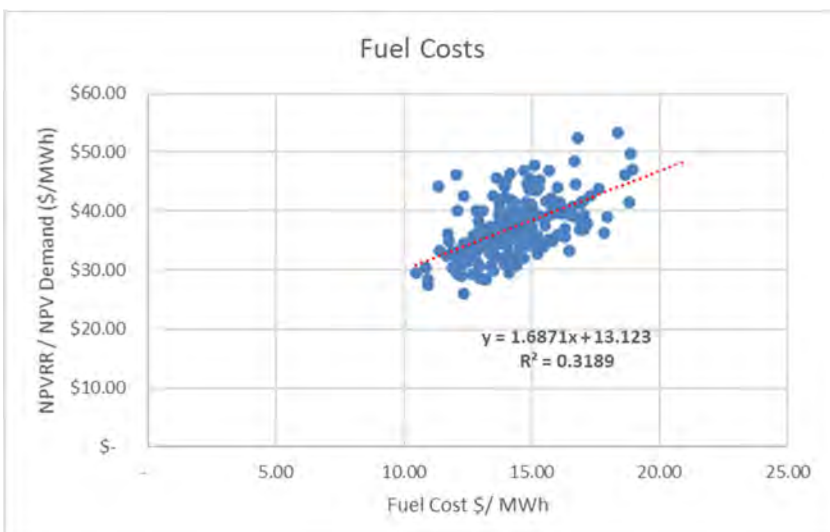
Figure 3





To further illustrate this, I did the same exercise for the Portfolio where case where there is a small CCGT (433 MW) by 2026. This portfolio was expected to be still weakly correlated with the fuel prices but to a greater degree than the preferred portfolio as it has more fuel assets and this is shown in the figure below where we note an R^2 of 0.32, almost double that of the Preferred Scenario. So, for this gas conversion option, the risk of gas price is more closely correlated to the portfolio's average costs than the Preferred Portfolio and hence gas volatility has much greater impact.

Figure 4



Q. Are there other aspects that you would like to highlight about the decision to build the two CTs?

A. Yes, I find that the decision to build the two CTs adds flexibility to CenterPoint Indiana South's generation assets to deal with uncertainties that can affect demand growth or the future development of the CenterPoint Indiana South's and MISO's generation portfolio.

The CTs provide diversity in generation technologies and have option to be converted in the future.

Q. Let's focus for a moment on the analysis of continued operations of A.B. Brown with upgraded emissions controls in the IRP. Is it a fair criticism to claim that the analysis was biased against the continued operation as the analysis considering the capital cost concentrated in 2025 rather than amortized over the life of the asset?

A. No, I don't think it makes a difference at all and it was really the preference of the modeler. There is a time value of money and this works both ways in discounting for NPV calculations and for annualization of investments so it can be recovered over the life of the asset. We do this using the Capital Cost Recovery factor ("CCR") that multiplied by the capital investment of an asset converts it into a uniform stream of payments throughout the life of the asset. This was done for the capital investment of solar, wind and new generation offered to the model as candidates for selection. However, in the case of the A.B. Brown upgrades the modeler had the actual expected cashflow and modeled as such. This is shown in the figure below. The NPV of this cashflow stream is (2019) $401.2 million at a discount rate of 7.71% equal to the CEI South's weighted average cost of capital used in the IRP[23].

[23] See pg. 257 of Volume I of the CEI South 2019/2020 IRP.

Figure 5

The analyst could have annualized the CapEx component above using the same discount rate above and 16 years amortization (the units would retire by the end of 2039) and produce a cashflow like the one below which has exactly the same NPV (2019) $401.2 million. Thus, there was no bias against the continuation of A.B. Brown, just the economics.

Figure 6

Q Should CenterPoint Indiana South have amortized the new CTs proposed in the Preferred Portfolio over a much shorter life?

A. No, I don't think so. Even if in the future Indiana or the EPA were to adopt a net-zero policy as for example New York's CLCPA that requires the state's generation to be zero emissions by 2040[24], there is still a role for peaking generation like the CTs, which could be burning renewable natural gas ("RNG"), Green-Hydrogen or another net-zero emissions fuel. I was part of the team that conducted a study for the NY Research and Development Authority ("NYSERDA") to assess how the grid would evolve leading to a 100% emissions grid by 2040[25]. In the study we found that the optimal expansion plan was a mix of storage and thermal generation that by 2040 would use RNG at a cost of $23/MMBTU and subject to an availability limit of 32TBTU/year. We found that in the optimal plan there would be approximately 17,200 MW of thermal generation in the system, including some of the existing generation that did no retire and new CTs and combined cycle plants added as part of the expansion plan[26].

For this reason, I don't think it is necessary or prudent to reduce the life of the assets as proposed.

Q As stated in "Response of CAC, Earthjustice, and Vote Solar to the Director's Draft Report for Vectren's 2019/2020 Integrated Resource Plan", do you agree that CenterPoint Indiana South's resource adequacy approach is inconsistent with the outcomes of MISO's policy change on the topic?

A. No, I don't think the changes in MISO policy will have a significant impact on the plans. Upon my review of the models, I appreciated that CenterPoint Indiana South made sure that the portfolios would likely meet both summer and winter requirements, and any seasonal requirement for that matter. Yes, as noted in CAC, et. al. response, CenterPoint Indiana South used the same PRMR of 8.8% of the MISO coincident peak across all months, however I don't expect that this approximation will result in the plans being inadequate as I illustrate below.

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[24] The New York Climate Leadership and Community Protection Act sets a goal of having a 100% emissions free electricity by 2040 (CLCPA) (see https://climate.ny.gov/-/media/CLCPA/Files/CLCPA-Fact-Sheet.pdf).

[25] See Appendix E: Zero Emissions Electric Gris in New York by 2040 https://brattlefiles.blob.core.windows.net/files/20842_initial_report_on_the_new_york_power_grid_study.pdf.

[26] See Table 4-1 of Appendix E referenced in the prior footnote.

First, Aurora's optimization ensured that there were enough resources to meet the most stringent yearly condition, which as expected happened in August of each year. This is shown in the figures below for 2030 for the Renewable+ Peak Gas, Renewable 2030 and High Technology portfolio, where the peak demand and reserve requirements are compared with the available capacity from resources across the year. In these figures the red line is the CEI South's coincident demand, and the dashed line includes on top of that the minimum reserve (8.9%) that Aurora maintained over this demand. This is compared with the capacity contribution, i.e., the ELCC I mentioned earlier, of all the resources in the portfolio including market capacity purchases that add up to a blue line "Total Resources" in the graphs.

As can be observed in the graphs even though the ELCC of renewable dropped in late fall, winter, and early spring (see the reduction in the top green area representing the renewable and effect in Total Resources - blue line), this drop in Total Resources is more than compensated in by the concurrent drop in demand resulting in greater margins between the requirement (dotted line) and the availability (blue line). This is particularly clear for the Renewable + Flexible Gas and Renewable 2030, where we see that in August the dotted line and the blue line coincide, and "Capacity Market Purchases" were required (red band) that in an "Annual" construct needs to be maintained throughout the year. A similar situation is observed for the Renewable 2030, where again we see that during August the available total resources (blue line) meet the requirements (dotted line) and capacity purchases are required. We also note that in winter the margin of the resources over the requirement is small. Finally, we see that for the High Technology case the available resources were always above this year requirements and no market capacity purchases were necessary.

Figure 7

Renewable + Flexible Gas Portfolio Demand, Reserves and Resources (MW).

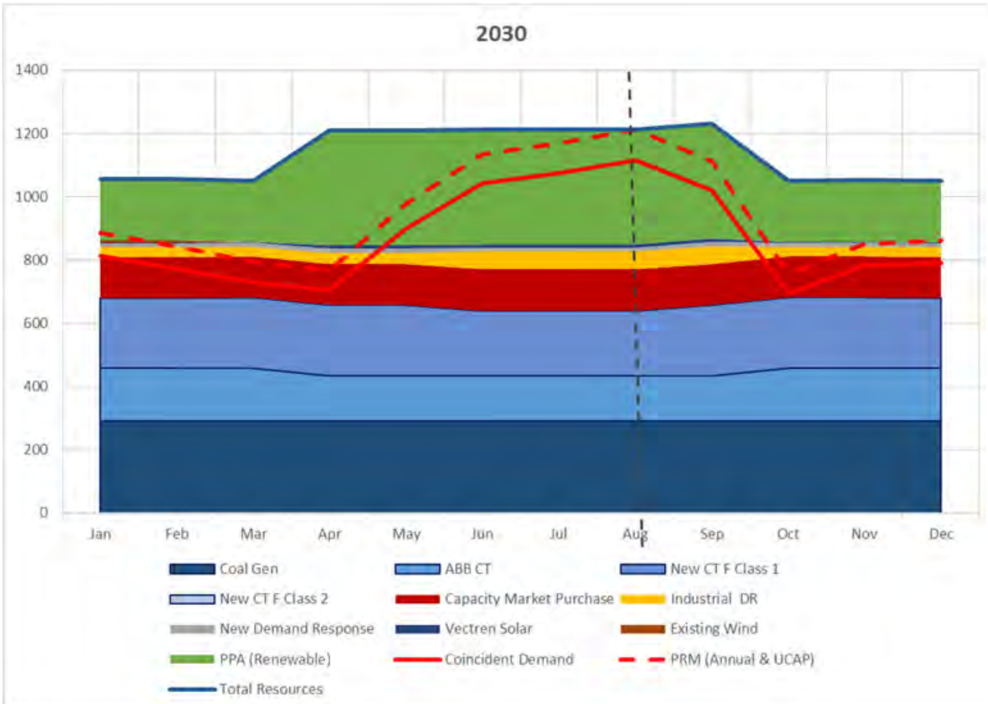


Figure 8

Renewable 2030 Demand, Reserves and Resources (MW).

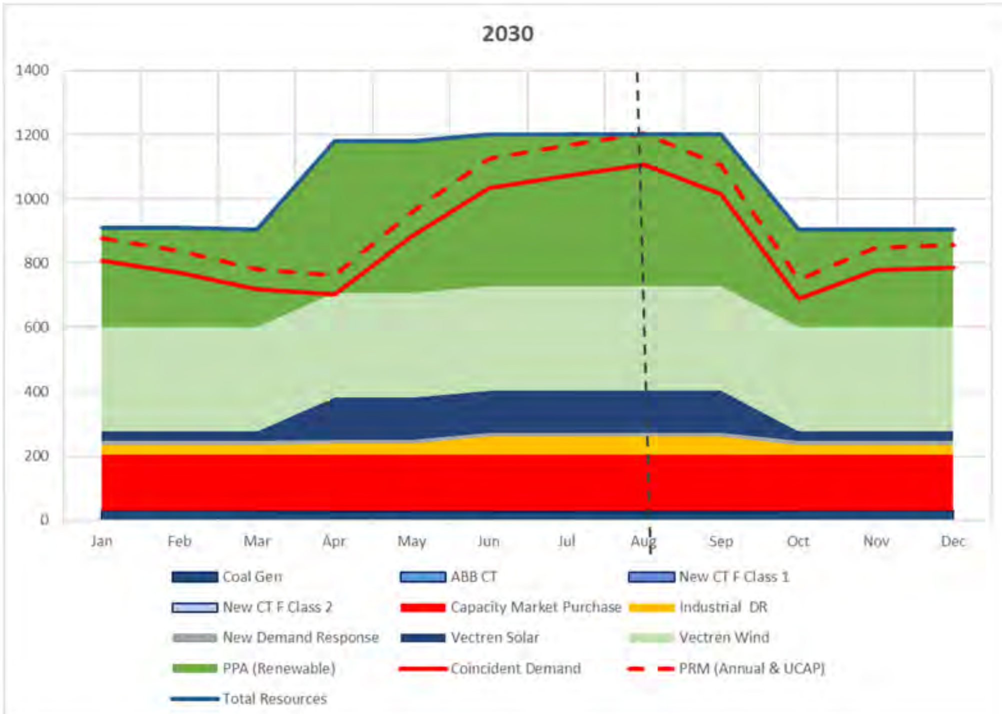
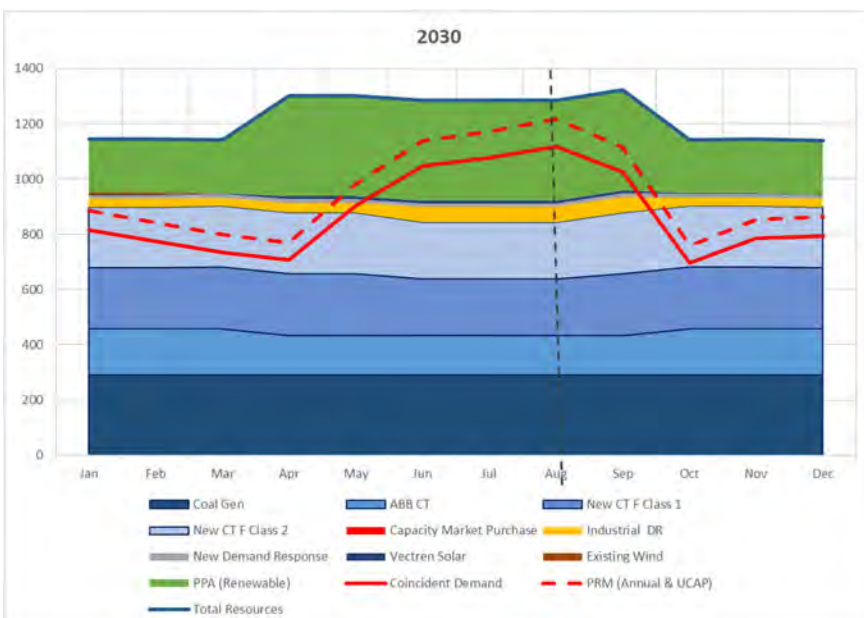


Figure 9

High Technology Portfolio Demand, Reserves and Resources (MW).



In summary, the August requirement defined the capacity needs of the portfolio and to meet it market capacity purchases are required on the Renewable + Peak and Renewables 2030 portfolio.

Q. Please continue with your response to the comment of CAC/Earthjustice and Vote Solar, do you think a MISO Seasonal Construct would have a major impact?

A. MISO has not yet defined what will be the final seasonal PRMR, however it is possible to illustrate how this may affect the Portfolios using the information shared by MISO on the "RAN Reliability Requirements and Sub-annual Construct"[27]. In MISO's document on page 23, the LRZ 6's Local Reliability Requirements ("LRR") (i.e., the amount of local resources to maintain an expectation that at maximum once every ten years there will not be enough resources to meet the load) are provided; and on page 31, the seasonal MISO wide PRMR% (UCAP) are also provided. On an annual basis for LRZ 6's and hence CEI South's, PRMR is given by the MISO System Wide PRMR. In MISO each LRZ needs to meet the largest of the MISO System-wide PRMR or a local reserve level called the Local Clearing Requirement (LCR), calculated as the Local Reliability Requirement less the LRZ's ability to import resources from MISO, which is given by the Zonal Import Ability (ZIA). Maintaining LRZ 6's Zonal Import Ability ("ZIA"), it is possible show that on a seasonal basis LRZ 6's PRMR should be given by the MISO System Wide PRMR, i.e., it is greater than LRZ 6's LCR. The figure below shows an illustrative impact of a MISO seasonal PRMR (UCAP based) of 7.1% in Summer, 18.5% for Winter, 22.3% for Spring and 13.8% for Fall for the 2030 demand and as before a comparison is made with the available resources. As can be observed the highest requirements occur in January, May, August, and September and are met by the available portfolio resources on those seasons. The only exception to the above is the Renewable 2030 for winter which may need to acquire a small amount of additional market capacity (~44 MW) to meet the requirement.

[27] RAN Reliability Requirements and Sub-annual Construct (misoenergy.org): https://cdn.misoenergy.org/20210203%20RASC%20Item%2004a%20Subannual%20Construct%20Presentation%20(RASC010,%20011,%20012)517859.pdf.

Figure 10

Renewable + Flexible Gas Portfolio Demand, Reserves and Resources (MW).

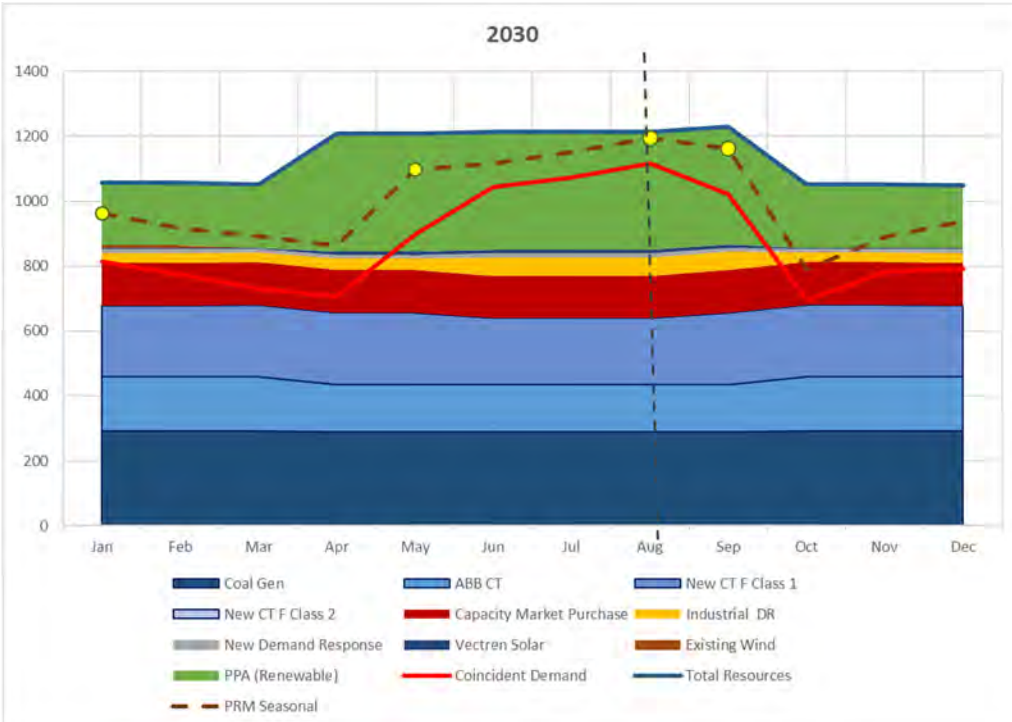


Figure 11

Renewable 2030 Demand, Reserves and Resources (MW).

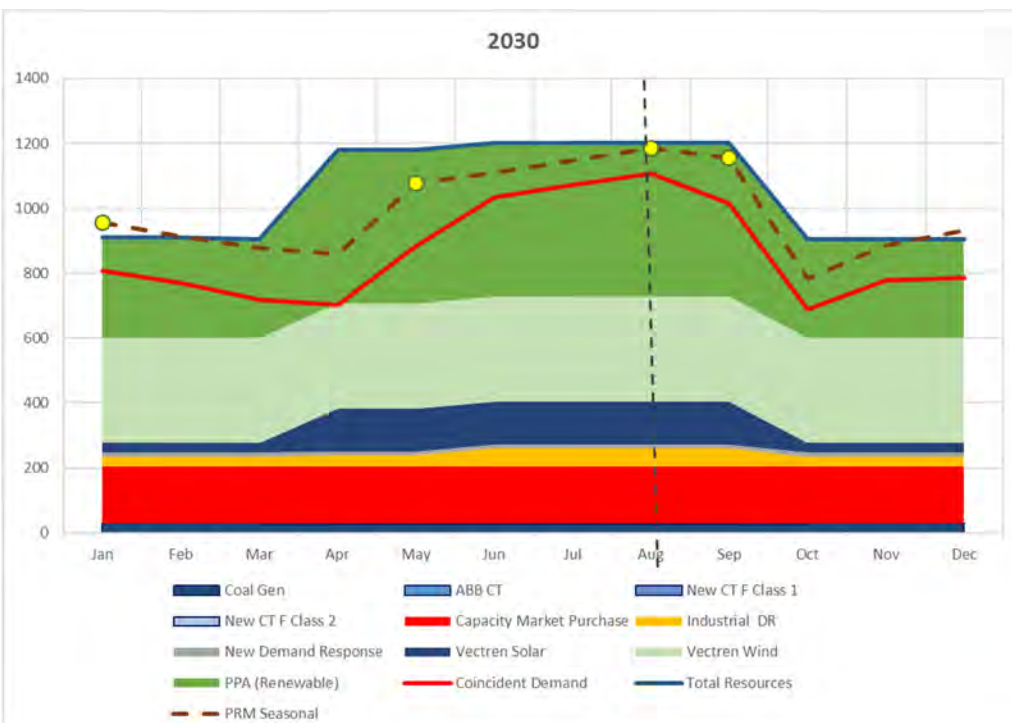
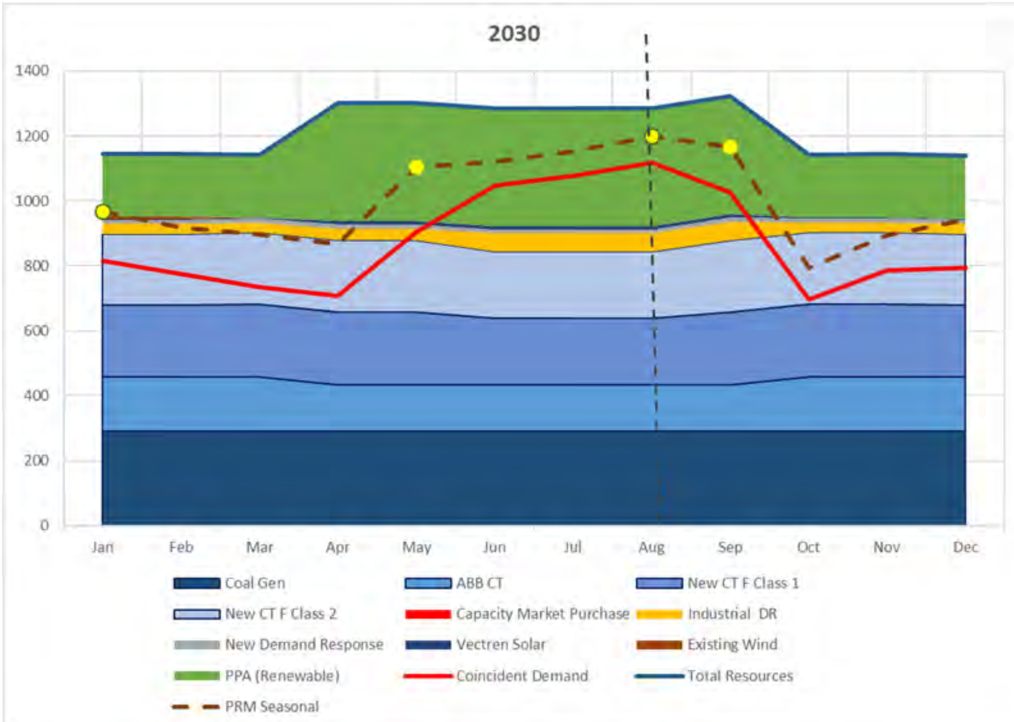


Figure 12

High Technology Portfolio Demand, Reserves and Resources (MW).



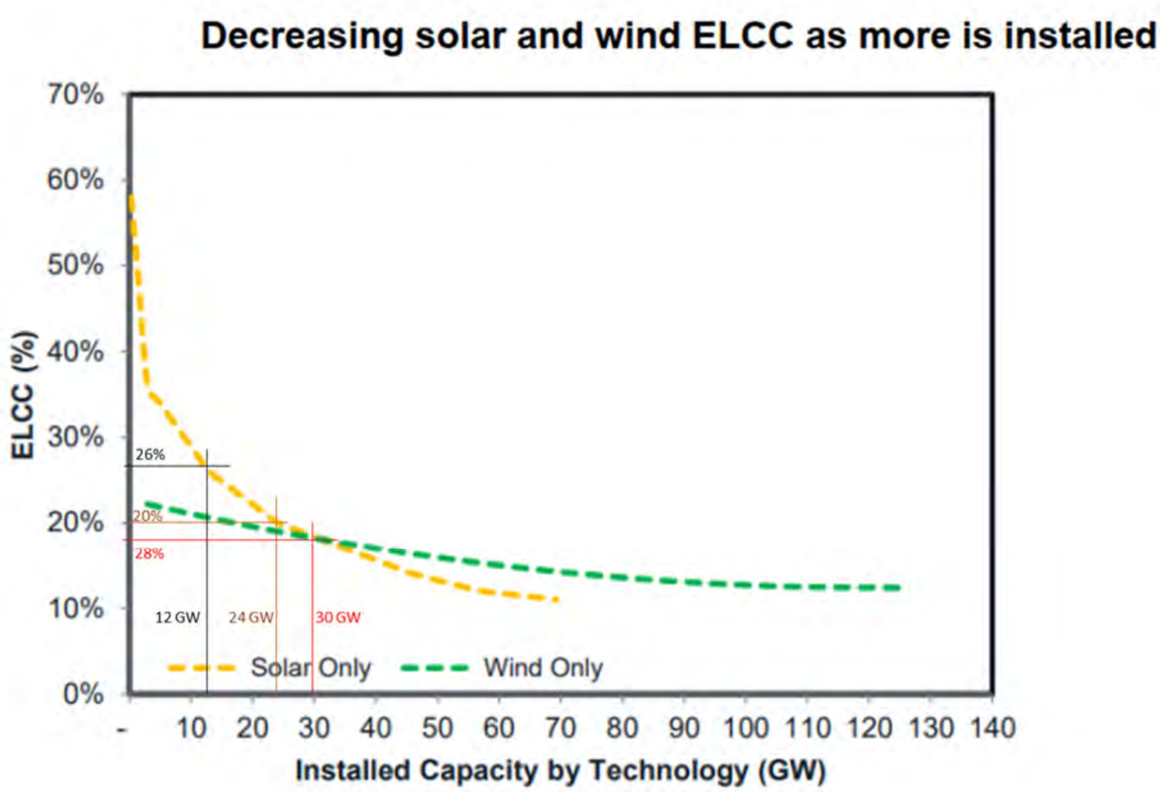
In summary the analysis above leads me to the conclusion that CenterPoint Indiana South's Preferred Portfolio as defined should fare well under a seasonal construct as well. Note again, the red band on Renewable + Flexible Gas and Renewables portfolios that show the capacity purchases, compared to the Preferred Portfolio.

Q **As stated in "Response of CAC, Earthjustice, and Vote Solar to the Director's Draft Report for Vectren's 2019/2020 Integrated Resource Plan", do you agree that the ELCC of Solar and Wind is understated and if CenterPoint Indiana South had used more appropriate values only one CT would be necessary?**

A. No, as I mentioned earlier the ELCC of renewable resources and storage decreases with the penetration and in this context, penetration is the amount of generation installed in the system as a whole, in this case MISO, not LRZ 6 or CEI South. For 2025 CenterPoint Indiana South used a ELCC for solar of 26% for summer and 6% for winter and reducing to 20% Summer and 4% winter for 2033, which is aligned with reasonable forecast of solar. As shown in Figure 5-5 of the IRP, derived from MISO´s Renewable Integration

Impact Assessment (RIAA) Assumptions Document and reproduced below[28], we see that MISO expects that solar will have an ELCC of 26% by the time the solar generation installed in its footprint reaches slightly over 12 GW and a value of 20% by the time the solar generation installed reaches slightly over 24 GW.

Figure 13



It is reasonable to expect that the higher rather than the lower forecast will materialize. By the end of 2020 MISO there were approximately 1,492 MW of solar generation in its footprint[29] and over 36 GW of solar in its interconnection queue[30]. Based on this alone it is reasonable to expect that by 2025 there will be more than 12 GW of solar in MISO's footprint and that by 2033 there should be 30 GW or more.

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[28] See MISO Renewable Integration Impact Assessment (RIIA) assumptions document V6, https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v7429759.pdf.

[29] Planning Year 2020-2021 Wind and Solar Capacity Credit (https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf).

[30] See MTEP 2020 pg. 23 https://cdn.misoenergy.org//MTEP20%20Full%20Report485662.pdf.

However, this is not the only evidence I see of the reasonableness of this assumption. MISO's Futures, which have the goal to provide bookends for the different generation technologies[31], forecast that for 2033 there will be a minimum of 7.2 GW of Solar on the pessimistic Limited Fleet Change ("LFC") Future, increasing to 13.5 GW of Solar in the Continued Fleet Change ("CFC") Future, 30.4 GW of Solar in the Accelerated Fleet Change ("AFC") Future, reaching a maximum of 42.7 GW in the Distributed and Emerging Technologies ("DET") Future. This is a quite wide range, but once combined with the status of the interconnection queue and the current tendency for an acceleration of solar generation as municipalities, states and utilities address the challenges of climate change; it stands to reason that the future solar generation should be more aligned with AFC or even the DET forecasts.

Hence and looking at the figure above we see that with 30 GW or more of solar in MISO's system a solar ELCC of 20% or lower is to be expected.

For winter, MISO currently uses a solar ELCC of 5%[32] and this will reduce as penetration increases.

Based on the above, I disagree with the statement that on the High Technology Portfolio there would be adequate reserves with only one CT. To illustrate this, I show below the gap between the Total Resources (blue curve) and capacity needs (dotted brown curve) for 2033 using the illustrative seasonal PRMR. As can be observed there are gaps across all seasons.

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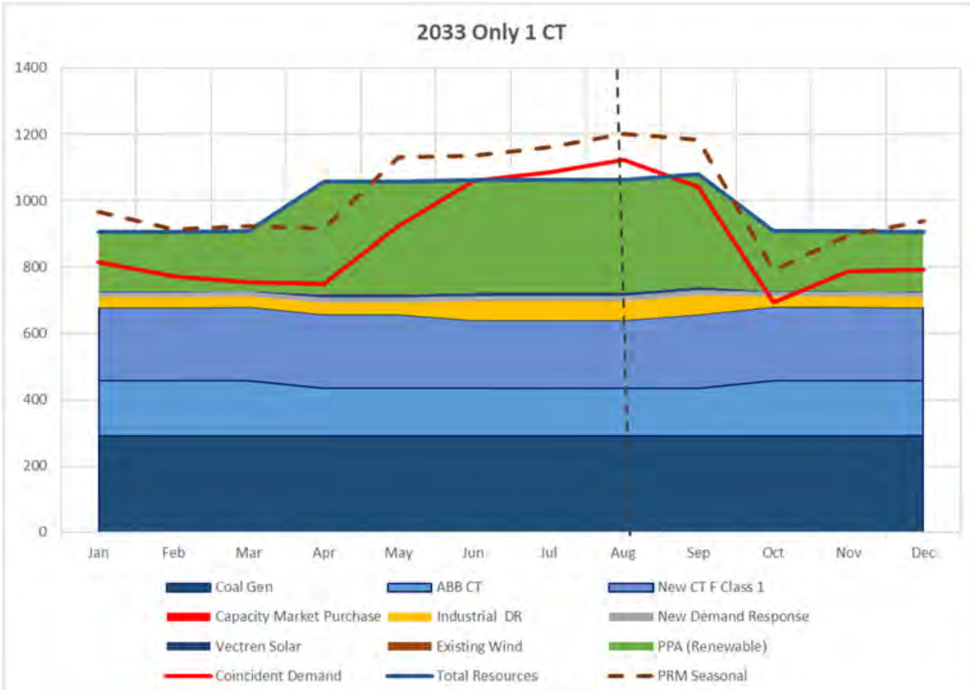
[31] See MTEP 2020 pg. 28 https://cdn.misoenergy.org//MTEP20%20Full%20Report485662.pdf.
[32] See page 24 of MISO RAN Reliability Requirements and Sub-annual Construct (misoenergy.org): https://cdn.misoenergy.org/20210203%20RASC%20Item%2004a%20Subannual%20Construct%20Presentation%20(RASC010,%20011,%20012)517859.pdf.

Figure 14

High Technology Portfolio Demand, Reserves and Resources (MW); 2033 with One CT.



III. CONCLUSION

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, at the present time.

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a CENTERPOINT ENERGY INDIANA SOUTH
(CENTERPOINT INDIANA SOUTH)

IURC CAUSE NO. 45564

DIRECT TESTIMONY
OF
NELSON BACALAO
PRINCIPAL CONSULTANT, SIEMENS PTI

ON

INTEGRATED RESOURCE PLAN PROCESS AND RESULTS

SPONSORING PETITIONER'S EXHIBIT NO. 6

ATTACHMENT NB-1

DIRECT TESTIMONY OF NELSON BACALAO

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Nelson Bacalao. My business address is 703 Detering St. Apt A Houston TX 77007.

Q. By whom are you employed and in what capacity?

A. I am a Principal Consultant at Siemens PTI ("Siemens PTI").

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting testimony on behalf of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("Petitioner", "CenterPoint Indiana South", "CEI South", or" Company").

Q. Have you previously testified before the Indiana Utility Regulatory Commission (the "Commission") or other public utility commission?

A. Yes, I testified before the Puerto Rico Energy Bureau First and Second IRP, Cases No. CEPR-AP-2015-0002 and CEPR-AP-2018-0001, on behalf of the Puerto Rico Electric Power Authority ("PREPA").

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support CenterPoint Indiana South's 2019/2020 Integrated Resource Plan ("2019/2020 IRP") process, as well as Petitioner's Generation Transition Plan, and address issues related to the cost estimates and assumptions associated with the new Combustion Turbines additions proposed in the Preferred Portfolio from the 2019/2020 IRP.

Q. Please summarize your education and experience relevant to your testimony in this case.

A. My relevant education and experience are discussed within my resume, a copy of which is attached as Petitioner's Exhibit No. 6, Attachment NB-1. I hold a Ph. D. in Electrical

Engineering from the University of British Columbia, Vancouver, BC, Canada, earned in 1987. I hold a Master Engineering (Electrical) degree from Rensselaer Polytechnic Institute in Troy, NY, earned in 1980. I hold an Electrical Engineer degree from Universidad Simon Bolivar in Caracas, Venezuela, earned in 1979. I have been employed by Siemens PTI since January 2006. I am a Principal Consultant based in Houston and my professional experience covers technical and strategic consulting services to utilities, governments, regulators, independent project developers, and the financial community, in domestic as well as international assignments. My work has been centered on power system planning with emphasis on Integrated Resource Planning, integration of renewable generation and the impact on transmission and distribution systems.

Q. Please summarize the history of Siemens PTI and your consulting relationship with CenterPoint Indiana South.

A. Siemens PTI is the consulting unit of Siemens Industry and has been in the power system consulting business since 1969 under the name of Power Technologies Inc. PTI became part of Siemens in January 2006. Siemens PTI's continued growth led to the acquisition of Pace Global Energy Services, to strengthen our capabilities in market analytics and general Energy Business Advisory. Siemens PTI provided support for Petitioner's 2019/2020 IRP and continues to be engaged to provide testimony support. With Siemens PTI, I have provided consulting services to CenterPoint Energy Houston Electric[1] on the areas of interconnection studies and North American Electric Reliability Corporation ("NERC") Compliance (CIP-14).

Q. Please summarize Siemens PTI's role in the 2019/2020 CenterPoint IRP process.

A. Siemens PTI contributed to Petitioner's 2019/2020 IRP process in several key areas. The main contribution was the management and development of the IRP modeling (including some input development), strategic consulting, participation in the stakeholder process, and scorecard development.

[1] CenterPoint Energy Houston Electric is a subsidiary of the same parent company (CenterPoint Energy, Inc.) as CenterPoint Indiana South.

Q. Please describe Siemens PTI's recent experience and expertise in structuring and leading integrated resource planning for utilities such as CenterPoint Indiana South.

A. Siemens PTI is a leading consultant for integrated resource planning, with extensive experience in structuring and facilitating IRPs for utilities throughout the United Stated and Caribbean. The following list represents a selection of recent clients that have engaged Siemens PTI to contribute to their IRP processes: Orlando Utilities Commission (FL), Peninsula Clean Energy (CA), East Bay Community Energy (CA), San Jose Clean Energy (CA), Clean Power Alliance of Southern California (CA), Clean Power San Francisco (CA), Memphis Light Gas and Water (TN), and other utilities and load servicing entities with whom we are under confidentiality agreements in Missouri and other states. Siemens PTI also assisted Petitioner in its 2014 and 2016 IRP processes and is currently assisting another Indiana electric utility with its IRP, currently in the stakeholder process.

Q. What have you done in preparation to develop opinions regarding the 2019/2020 IRP and CenterPoint Indiana South generation plan?

A. I did not have a direct role in preparing the 2019/2020 IRP; hence, I am bringing my independent view of how the process was conducted. In order to conduct my review, I read the IRP reports, and reviewed the various stakeholders' filings and IRP workpapers.

II. <u>MODELING, GENERATION PLANNING, AND SCORECARD</u>

Q. Have you reviewed the documentation filed by CenterPoint Indiana South on the IRP and the corresponding workpapers and models?

A. Yes, I have. The volume of information is quite substantial, and I have sought to became familiar with the rationale used by CEI South to identify the Preferred Portfolio with the support of my colleagues .

Q. Are you aware that the Preferred Portfolio (High Technology) includes the installation of two gas turbines rated 236 MW each?

A. Yes, I am aware of that recommendation of the Preferred Portfolio and reviewed the reasons behind the recommendation.

Q. Describe your view on the approach used in the IRP for selecting the Preferred Portfolio's two gas turbines.

A. In its Order in Cause No. 45052, the Commission explained that long-term risk is an important factor to be considered in the context of generation proposals: "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." Cause No. 45052 Order, p. 20. Petitioner's Witness Steven C. Greenley further addresses this concept in his testimony. I would describe this as the risk of buyer's remorse: the risk that a decision is made today which the Company and stakeholders later regret. Thus, the analysis should provide the decision makers information on the performance that these decisions have under future states of the world and identify which decisions are most likely to perform best and minimize the chances of buyer's remorse or regret.

The approach that Siemens PTI uses to analyze portfolios is to analyze in detail those portfolios that perform best across the relevant metrics and make a recommendation by identifying the portfolio that minimizes the risk. To achieve this, my approach is to review portfolio decisions and identify those that minimize the impact of having it wrong – the impact of an asset becoming "uneconomic" in the Commission's words. I sometimes call this identifying the risk and impact that a decision will later be regretted by the utility, and hence its customers and stakeholders. Based on my review of the analysis done by CEI South, I find it consistent with the approach above and I think the decision to build the two combustion turbines ("CTs") is consistent with the public convenience and necessity in part because it fulfills the Company's needs for capacity and peaking energy with generation resources that the Company and its stakeholders are unlikely to regret.

Q. Can you please elaborate?

A. We are entering a period of tremendous transition in the power generation industry. For decades, the industry has primarily relied upon fossil fuel for its generation resources, more specifically coal. In the recent past and over the coming years, much of that coal-fired generation will be retired as the industry transitions to portfolios consisting much more extensively of renewable resources. Our grid cannot switch entirely to renewable resources, however, because renewables must be supported by dispatchable power. This is not simply because of the intermittency of renewables but also is a function of the contribution that they provide to support the system peak and the required reserves. In the wintertime, with shorter days, there will not be sunlight during the evening peak and even for summer, as more photovoltaic generation is added to the system, net peak displaces to the evening, reducing the contribution of the renewable. So, the challenge becomes identifying the proper mix of renewable resources and dispatchable resources. Dispatchable resources will be more susceptible to regret if gas prices rise; renewable resources will be more susceptible to regret if capacity prices rise. A portfolio that mitigates the risk and impact of regret is a portfolio that navigates well through these often-competing risks. Let's take one risk factor at a time and assess how this decision plays out for the Preferred Portfolio with the CTs[2].

Q. How do the portfolios compare when considering the risk of gas price volatility?

A. The CTs' role in a portfolio is to provide peaking power and reserves. The peaking power functionally refers to the dispatch of generation during those peak load hours when there is insufficient base load generation or renewables in the system to supply the load. This typically occurs in relatively few hours per year. The reserve functionality refers to standing-by to supply the load in case a generation outage occurs. This all means that the CTs, as opposed to other base load generation (e.g., the Combined Cycle generators or Steam Turbine generation), run and burn gas only for a few hours during the year and hence are much less affected by gas price fluctuations. In the specific case of the Preferred Portfolio, the CTs have a very low capacity factor[3], an average of approximately 3% for the planning period for Reference Case conditions, which is much lower than those typical for base load generation (60% or higher). Another way of seeing this is considering that the cost of fuel for peakers typically represents about 2% of the net present value of the revenue requirements ("NPVRR"), thus the gas price may double and only have an effect of 2% increase in the NPVRR.

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[2] These are the other portfolios that had the lower net present value of the revenue requirement ("NPVRR") and performed well across a wide range of factors: Reference Case, Renewable + Flexible Gas, and Renewable 2030 (See Figure 8-8 of the 2019/2020 IRP Volume 1 pg. 251).
[3] Capacity Factor = Energy Produced / (Installed Capacity x hours of the year).

Another aspect to consider is that CTs can be turned on and off with great flexibility which makes them a good companion to intermittent renewables. In contrast, steam gas generation as would be the case of a converted A.B. Brown to gas is much less flexible and can be locked to run at minimum levels as it cannot be turned off and on as frequently. As a reference, the table below shows the NPVRR of the ABB1 + ABB 2 Gas Conversion scenario under reference condition and the present value of the fuel cost for the converted ABB1 and ABB2 and we see that represents 3.6% of the NPVRR. On the other hand, for the Preferred Portfolio (i.e., the High Technology Portfolio), the present value of the fuel costs represents 2%, 44% less. We also note in this table that with the exception of the Renewable 2030 Portfolio that stops using gas by 2030, the fuel cost of the Preferred Portfolio as a percentage of their NPVRR is the lowest among the least cost portfolios.

Table 1[4]

	NPVRR M$	NPV NG Costs for Peaking Units M$	NG Cost as % NPVRR
Bridge ABB1 + ABB2	$2,837	$101.92	3.6%
Preferred Portfolio – High Technology	$2,679	$52.76	2.0%
Renewables 2030	$2,678	$37.78	1.4%
Reference Case	$2,616	$65.47	2.5%
Renewables + Flexible Gas	$2,600	$55.95	2.2%

Q. How does the risk of higher capacity prices affect the portfolios?

A. As I explained previously, those portfolios that are more reliant on dispatchable power face a higher risk from gas price volatility; however, those portfolios more reliant on renewable resources will face a higher risk from capacity price volatility. CenterPoint Indiana South as a Midcontinent Independent System Operator ("MISO") member must meet the MISO Planning Reserve Margin Requirement ("PRMR"). In the IRP, a Planning Reserve Margin based on Unforced Capacity ("UCAP PRMR") requirement of 8.9% of the coincident peak load[5] was used, which is in line with MISO's requirements[6] and must be met by the capacity contributions of the resources in the portfolio or by market capacity

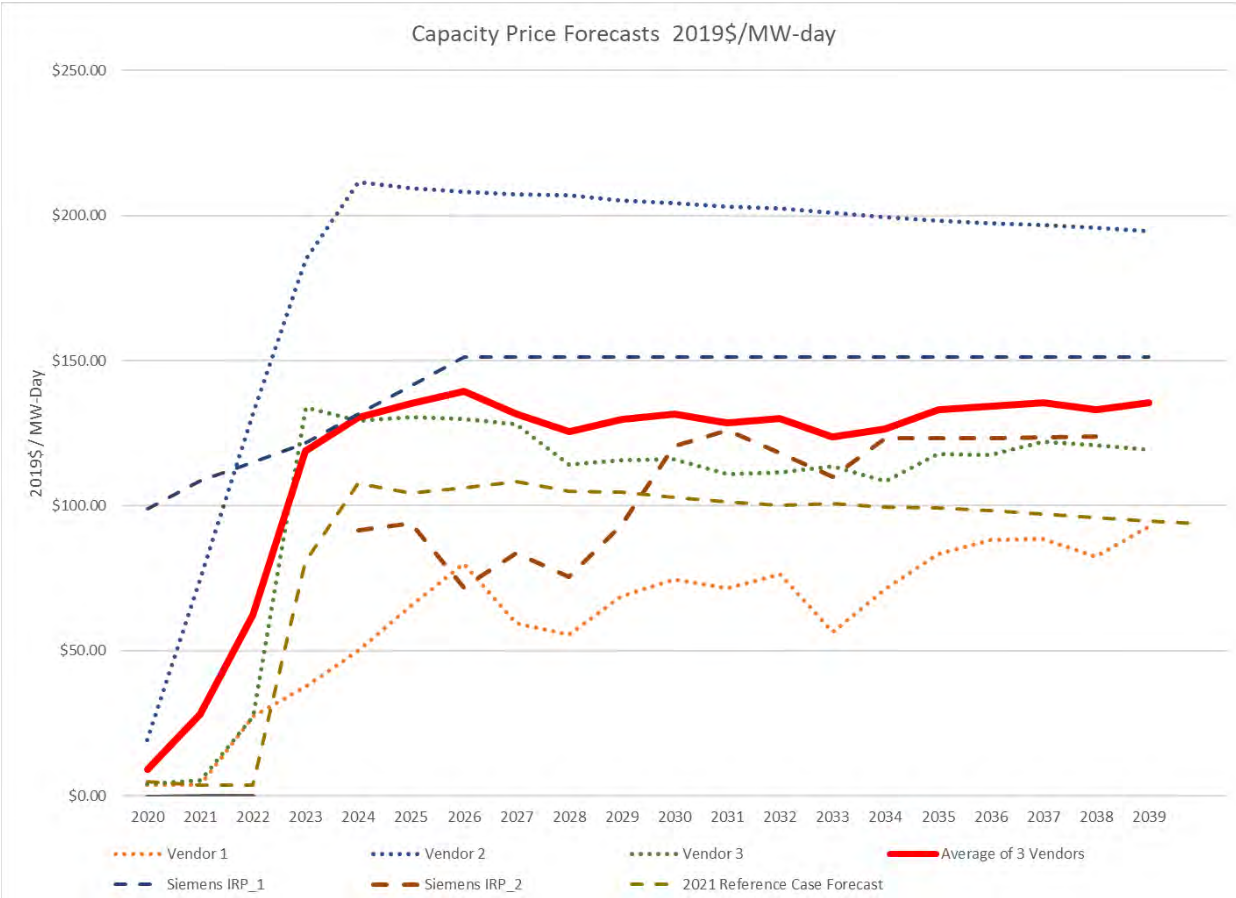
[4] Includes updates to capture fixed cost update to conversion portfolio (Bridge ABB1 + ABB2).
[5] This is CenterPoint Indiana South's load at the time of MISO's system wide peak.
[6] 2019/2020 IRP Volume 1, pg. 160 and MISO's Planning Year 2020-2021 Loss of Load Expectation Study Report.

purchases. Each of the resources owned or contracted by CenterPoint Indiana South contributes to meet the PRMR requirement and gas generators like the CTs contribute between 90% to 95% of its installed capacity to meet it[7]. Any shortfall must be procured in MISO's Capacity Auction, whose prices can be very volatile and difficult to predict as they depend on a tight balance between offer and supply. This can be observed by noting the widespread in the forecast as shown Figure 7-7 of the IRP Volume 1 and reproduced below, where we see that the high forecast is more than double the low forecast and gets close the MISO's ceiling equal to the cost of a new entry ("CONE") to provide the reserves ($257 MW/day).

Another aspect to consider is that in the below while the forecast for Vendor 1, which is PACE (a Siemens Company at the time), is the lowest, forecasts change as vendors have more information and consider the situations of the companies that will have to go to market to secure capacity (either spot or bilateral). In the figure I also added Siemens current Reference Capacity Forecast for MISO and the capacity forecast used for two IRPs in MISO that considered the particularities of the utilities. As noted, all updated forecasts are above those of Vendor 1 (PACE).

[7] Table 8-6 of CEI South IRP Volume 1, pg. 249.

Figure 1



Moreover, there are various risk factors that seem to indicate the potential for higher prices. The Local Resource Zone ("LRZ") 6, where CenterPoint Indiana South is located, does not have enough local resources to meet its Local Reliability Requirements ("LRR") and is dependent on imports from other MISO LRZs[8]. This makes Zone 6 dependent on the generation surplus in other zones, that may or may not materialize, adding practical deliverability risks and price risks. The capacity shortfall in MISO and specifically in Zone 6 is only expected to grow in the coming years, as noted in Petitioner's Witness F. Shane Bradford's testimony.

[8] Figure 5.9 of 2019/2020 IRP Volume 1 pg. 144 and Table 6-1 to 6-3 of MISO's Planning Year 2020-2021 Loss of Load Expectation Study Report.

The more heavily reliant a portfolio is on renewable resources, the greater the exposure to capacity price volatility risk. As more solar generation enters the market, the system resource adequacy determinations are likely to evolve from summer peaking to summer/winter peaking or a four seasonal construct as currently considered by MISO[9]. As I noted previously, there is a significant difference in the contribution of solar generation to meet the summer peak versus the winter peak. This is largely a function of the shorter days and the occurrence of the peak after dark. In the summer, much of the evening peak occurs while the sun is still shining; in winter, the evening peak occurs after dark. Additionally, as solar generation penetration increases, the summer peak contribution is also affected. As more renewable enter the system, the peak of the net load[10], which accounts for the reduction of renewable generation, displaces to later in the day when renewable resources also contribute less. This effect is captured in the industry with what is called the Effective Load Carrying Capability ("ELCC"), which is a measure of how much a resource can be depended on to supply the peak. For fossil fuel generation. this value is quite high — typically over 90% of the installed capacity; for solar it is currently 50% in MISO of the installed capacity for summer, and it reduces to only 5% for winter, as explained above. Both values for solar will reduce further as penetration increases. For wind generation, the ELCC is more uniform during the year and in the order of 15% for summer, spring, and fall, and 20% for winter.

As can be appreciated, as more and more fossil fuel generation retires and is replaced with renewables, the need for dispatchable power becomes more pronounced. A construct requiring meeting a winter PRMR requirement would have very low contribution of solar and would have to be met with thermal resources, wind resources, and storage[11]. As we have more and more solar penetration into the overall grid portfolio, this will drive up the cost of capacity in the market. The more reliant a portfolio is on renewables, the more it

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[9] RAN Reliability Requirements and Sub-annual Construct (misoenergy.org): https://cdn.misoenergy.org/20210203%20RASC%20Item%2004a%20Subannual%20Construct%20Presentation%20(RASC010,%20011,%20012)517859.pdf.

[10] The net load is the effective load of the system accounting for the effects of the renewable generation output.

[11] See Figure 8-6 and 8-7 of the 2019/2020 IRP Volume 1 pg. 249 for ELCC of thermal, wind and solar and its projections.

will rely on capacity purchases. If capacity prices rise more than forecasted, it increases the risk that a particular decision will be regretted.

The Preferred Portfolio with the two CTs is much less susceptive to the impact on changes in capacity prices as it has the lowest forecasted amount of capacity purchases of the four least cost portfolios[12] and hence it has the lowest exposure to this risk. The table below shows for the four least cost portfolios and for the case where A.B. Brown is converted to gas, the average market capacity purchases, the present value of the associated cost and how much it represents as a percentage of the Net Present Value for the portfolio revenue requirements ("NPVRR"). We observe that the Renewable 2030 has the greatest exposure followed by the Reference Case and Renewable + Flexible Gas, A.B. Brown Conversion ((Bridge ABB1 and Bridge ABB1 +ABB2) and the preferred portfolio (High Technology) has the least exposure.

Table 2[13]

Scenario	Average Capacity Purchases (2020-2039) MW	NPV of Capacity Purchases Cost M$	% NPVRR	NPVRR M$
Renewables 2030	137	53.51	2.0%	2,678
Reference Case	111	39.78	1.5%	2,616
Renewables + Flexible Gas	109	39.18	1.5%	2,600
Bridge ABB1	108	39.70	1.5%	2,683
Bridge ABB1 + ABB2	46	11.97	0.4%	2,837
Preferred Portfolio- High Technology	5	2.59	0.1%	2,679

Another aspect to consider is that the ELCC of storage declines as penetration increases[14] and the Preferred Portfolio would be only marginally affected by a reduction of ELCC of

[11] Renewable + Flexible Gas

[13] Includes updates to capture fixed cost update to conversion portfolios (Bridge ABB1 and Bridge ABB1 + ABB2). Also includes updates to capacity purchases and capacity purchase values.

[14] Storage was conservatively modeled in the IRP with a constant ELCC of 95%, however this value is likely to decline as more storage is added to system. For example, on a recent study for NY we are using 75% for a 4 hours battery as recommended by NYSO for penetrations greater than 1000 MW (see Expanding Cap. Eligibility:

storage as it only has 50 MW installed in 2039, which is not the case for the Renewable 2030 that has 360 MW of storage by 2031. Simply put, as the level of storage increases in the MISO Market, the level of accredited capacity would go down. It is the same phenomenon discussed regarding solar resources. This risk was not considered within the IRP but is an important factor to consider when evaluating a portfolio that relies heavily on storage.

Q. What conclusions do you derive from the above?

A. I conclude that the Preferred Portfolio with two CTs has very low exposure to the risk of high fuel prices while providing almost full protection to the risk of high capacity prices. The Preferred Portfolio has nearly the least exposure when considering gas price risk, with only Renewables 2030 being less exposed. On the capacity side, the Preferred Portfolio has the lowest risk of exposure. Notably, the Renewables 2030 is most exposed on the capacity side. The Preferred Portfolio navigates these two competing variables very well and better than the other portfolios. In other words, compared to other portfolios, the effects of being wrong and regretting the decision are less pronounced.

Q. How does the possibility of battery storage affect the analysis?

A. Storage is a useful tool that can help address solar's inherent incapability to meet the system peaks and shift energy to those times when the sun is not shining. To address whether battery storage would have been a more economical solution than constructing two CTs, CenterPoint Indiana South conducted a sensitivity analysis where the CTs were replaced by storage that would provide similar amounts of reserve as the CTs. The storage was selected from a bid received on the All source RFP[15] and consisted of eight modules with 76.2 MW of three-hour storage each, totaling 609.6 MW. With expected ELCC of 71%, the resulting capacity value of 434.3 MW is slightly higher than the capacity value of the two CTs (409 MW).

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https://www.nyiso.com/documents/20142/5375692/Expanding%20Capacity%20Eligibility%20030719.pdf/19c4ea0d-4827-2e7e-3c32-cf7e36e6e34a) and in an study for CAISO a value as low as 54% was identified for high levels of storage penetration (see Energy Storage Capacity Value on the CAISO System: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/2019-20%20IRP%20Astrape%20Battery%20ELCC%20Analysis.pdf).

[15] See Section 6.1.1 of the 2019/2020 IRP Volume 1 pg. 149.

Q. Have you reviewed that sensitivity analysis?

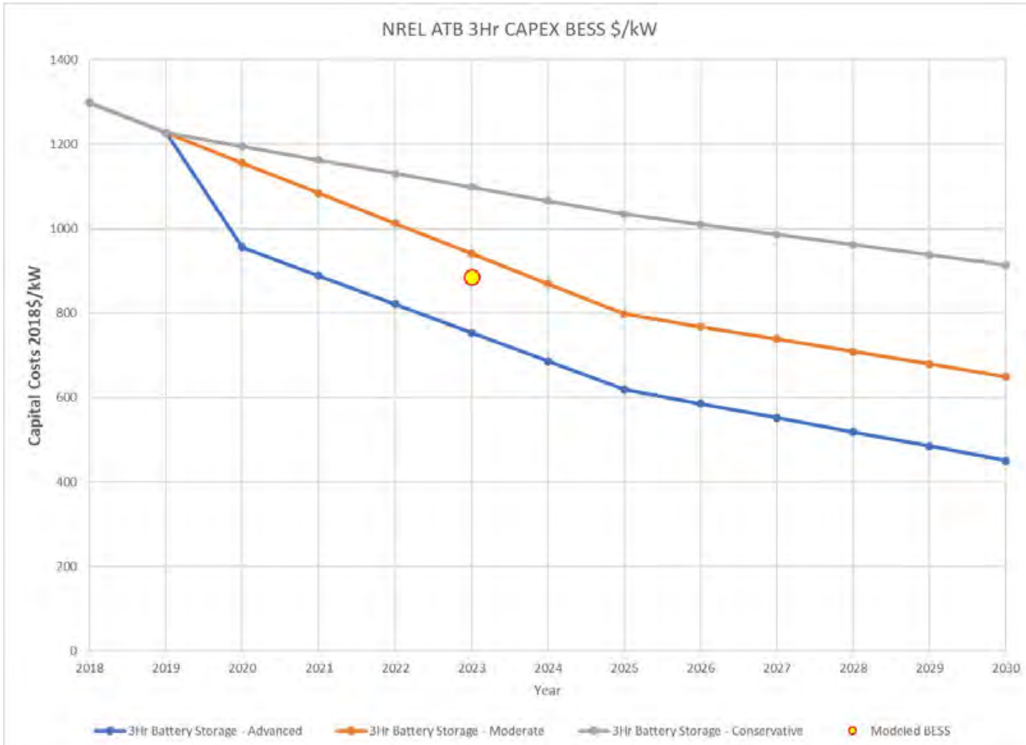
A. Yes. I reviewed the sensitivity calculations and identified that the building storage resulted in an increase of 5% on the NPVRR of the portfolio. This was driven by the higher capital and fixed O&M costs of the storage that are approximately 54% higher than corresponding costs of the CTs and result in an 17% increase in the overall capital and fixed O&M costs component of the NPVRR. This increase in cost is partly compensated by a reduction in fuel costs (5% reduction) and emissions cost (2% reduction).

Q. Are the prices for storage assumed in CenterPoint Indiana South's sensitivity analysis reasonable?

A. Yes. First, these are actual prices that were submitted in response to an actual RFP. But given the importance of the Storage PPA costs in driving the results above, I further compared this cost with the 2020 NREL's ATB forecast[16]. To get a comparable capital cost in $/kW, I subtracted from the PPA yearly payments the expected component for Fixed O&M costs (using the ATB forecast) and then determined the implied capital using the same discount rate used in the IRP with a 15 year life. I further considered that CenterPoint Indiana South would have to enter this contract approximately two years ahead of the in-service date of the project (i.e., 2023). The figure below shows the result of the analysis where we note that the cost is below the expected trend (Moderate) and somewhat higher than the minimum expected costs (Advanced), thus confirming the adequacy of the values used in Petitioner's 2019/2020 IRP. In short, I agree with the conclusion that additional storage will be more costly than the two CTs and attempting to replace one or both CTs with storage would be an uneconomic decision.

[16] https://atb.nrel.gov/electricity/2020/data.php.

Figure 2



Q. Are there other issues that should be considered besides economics when evaluating storage as a potential alternative?

A. Yes. As discussed earlier, the ELCC of storage may not be constant over time and as the penetration increases, it could decrease and possibly significantly as identified in the California Independent System Operator (CALISO) study and in the New York Independent System Operator (NYISO) studies (see footnote 14 *supra*). Moreover, the storage considered was three hours duration and any real-life requirement with longer duration requirements could not be met. This is not the case with the CTs that can be in service for extended periods of time.

In summary, I think that the selection of battery energy storage in lieu of the CTs is not a robust solution and there is greater risk that it will result in higher costs and reduced services to CEI South's customers.

I think this summarizes well why I am of the opinion that CenterPoint Indiana South's decision to build the two CTs is a prudent decision for CenterPoint Indiana South and its customers and is in the public interest.

Q. Can you describe the Balanced Scorecard Methodology used in CenterPoint Indiana South's IRP?

A. The Balanced Scorecard is a method to present the results of an otherwise complex analysis effectively and concisely. Across the top are the key objectives to be assessed and this includes affordability typically measured by the NPVRR; environmental factors for example CO_2 emissions minimization; and risk factors such as risk of the NPVRR being higher than expected, or overreliance on an energy and capacity market that can be volatile. There can be other factors in the Balanced Scorecard, and I understand that the factors used by CenterPoint Indiana South were vetted via an extensive stakeholder process.

In the scorecard, each line contains the results for different portfolios allowing comparison.

The scorecard can be based on deterministic results, but in most advanced procedures the results of the Monte Carlo stochastic simulations are used. This was the case in CenterPoint Indiana South's IRP, which allowed, for example, to show the cost uncertainty by looking at the 95th percentile (i.e., the cost or value that would be exceeded only 5% of the time) across 200 iterations[17].

I have used the Balanced Scorecard in multiple assessments and in my opinion, it is a powerful tool to visualize the performance of multiple portfolios at a glance. The scorecard typically uses shades of the color green to depict favorable outcome and by inspection it is relatively easy to identify the best performing portfolios, allowing the identification of what is sometimes called the decision set, i.e., those portfolios that behave best in

[17] The 95th percentile is the value that is exceeded only 5% of the time and the greater the difference of this value to the mean is indication of the sensitivity of the portfolio to one or more uncertainties. CenterPoint Indiana South considered the following variable uncertain (stochastics); Load (energy and peak), natural gas (high uncertainty variable), coal, CO_2 emissions costs, capital costs for solar, wind, BESS, CCGTs and CTs.

comparison with the rest and are likely to contain the preferred portfolio and should be studied closely[18]. In the case of CenterPoint Indiana South's IRP, the Reference Case, the Renewable + Flexible Gas, the Renewable 2030 and the High Technology are clearly members of this decision set[19].

Q. Is the Monte Carlo 95th percentile approach the only way that cost risk can be analyzed?

A. No, there are other ways and I also looked at them to conclude that CenterPoint Indiana South's proposal to build the two CTs is prudent.

First, I look at how the different Portfolios NPVRR changes when subjected to different "states of the world" as described in the Scenarios that CenterPoint Indiana South considered[20]. For each of those scenarios, there is always a Portfolio that performs best (i.e., has the lowest NPVRR and performed well across other metrics) and would be the preferred decision if we had perfect foresight; this is sometimes called the No-Regret Portfolio for the given state of the world. Then I compare the other Portfolios under this state of the world (or future) and assess the difference with respect of the No Regret Portfolio and the difference is the degree of "Regret". With this approach we can factor the degree that different Portfolios benefit from a favorable outcome (e.g., a portfolio that could benefit more from a reduction in capital costs of renewable and storage than others)[21] and by how much they are shielded from adverse outcomes.

Using the results reported in in the IRP, I determined the Regret as defined above and calculated the simple average of the regret across the scenarios considered. Below I show the results of this assessment. This is a simple average of the deltas from the lowest NPVRR under the five different scenarios evaluated in the IRP. In other words, this

[18] See for example the MLGW IRP (http://www.mlgw.com/images/content/files/pdf/MLGW-IRP-Final-Report_Siemens-PTI_R108-20.pdf) Exhibit 10 and subsequent analysis of Portfolios 5, 9 and 10 together with the TVA option that were included in the decision set.

[19] Figure 8-8 of Volume I of the 2019/2020 IRP.

[20] See Figure 2.5 of the 2019/2020 IRP pg. 94.

[21] The convenience of assessing the upside of Portfolios was also expressed in the Director's report where it indicates that "[CenterPoint Indiana South] uses the 95th percentile as the metric for cost uncertainty. This is reasonable but it ignores the uncertainty around the potential for lower-than-expected cost. It is possible that a portfolio has more downside cost benefit than other portfolios, but this was not considered by [CenterPoint Indiana South]."

analysis is focused purely on NPVRR, and each of the various scenarios are equally rated. For example, it assumes the risk of the "Low Regulation" scenario is the same as the risk of the "High Regulation." We see below that Renewable + Flexible Gas has the lowest average regret, i.e., the chances of regretting the decision under an adverse future are lower. This Portfolio is followed by the Reference and then the Renewable 2030, the Bridge ABB1 and High Tech (Preferred Portfolio) that are fairly close.

Table 3[22]

Regret assessment $000

Portfolio	Base Case	80% CO2 Reduction by 2050	High Technology	High Regulation	Low Regulation	Avg of Regret	Rank
P08 Renew ables + Peak Gas	$ -	$ -	$ -	$ 123,706	$ 36,223	$ 31,986	1
Reference	$ 42,565	$ 44,895	$ 47,183	$ 210,031	$ -	$ 68,935	2
P09 Renew ables 2030	$ 78,052	$ 55,902	$ 180,539	$ -	$ 221,339	$ 107,166	3
P04 Bridge ABB1	$ 101,080	$ 94,319	$ 122,798	$ 238,606	$ 78,096	$ 126,980	4
P10 - High Tech Portfolio	$ 103,734	$ 94,207	$ 82,493	$ 290,352	$ 69,030	$ 127,964	5
P06 Diverse Small CCGT	$ 180,813	$ 126,386	$ 158,724	$ 308,956	$ 140,938	$ 183,163	6
P02 - Bridge BAU- 2029	$ 252,743	$ 195,478	$ 273,049	$ 385,153	$ 25,078	$ 226,300	7
P03 Bridge ABB1 CCGT	$ 322,024	$ 259,469	$ 302,953	$ 431,050	$ 287,972	$ 320,694	9
P05 BridgeABB1 & ABB2	$ 254,789	$ 228,236	$ 266,294	$ 361,044	$ 218,172	$ 265,707	8
P01 BAU	$ 558,437	$ 448,502	$ 597,712	$ 671,137	$ 32,426	$ 461,643	10

Q. This analysis would seem to suggest the Renewable + Flexible Gas would have the least adverse impact if the decision were later regretted under this simple analysis. Is that the correct reading?

A. Yes, but with a qualification. Looking into this I noted that except for the Renewable 2030 and the Bridge ABB1, all the lowest regret Portfolios had a 236 MW CT built in 2024 and the Renewable + Flexible Gas had another built in 2033 versus the Preferred Portfolio that had it built together with the first unit. Thus, the option to delay the construction of the second turbine to 2033 in accordance with the Renewable + Flexible Gas should be considered. I investigated this and realized that first there are important construction efficiencies in building the two CTs together. As shown in Attachment 1.2 of Appendix 2

[22] Includes updates to capture fixed cost update to conversion portfolios (P04 Bridge ABB1, P03 Bridge ABB1 CCGT, and P05 Bride ABB1 & ABB2).

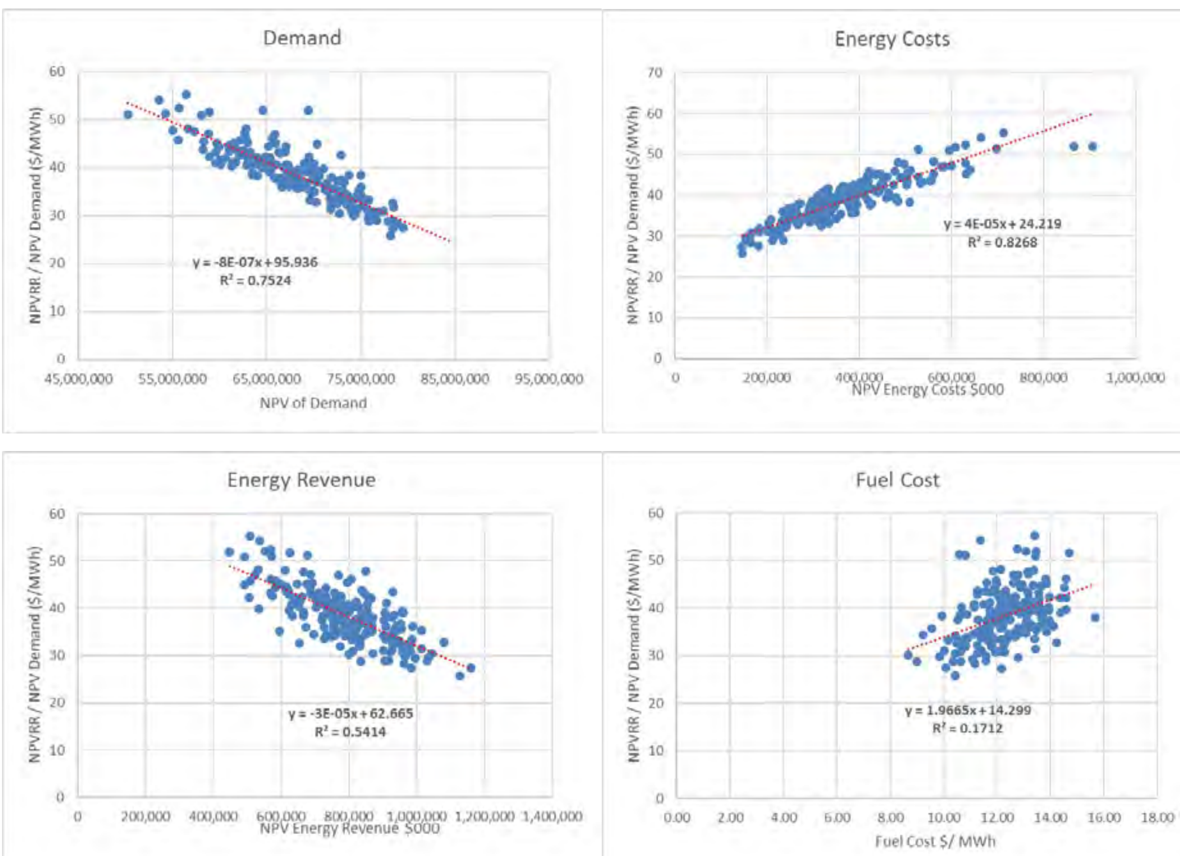
of the 2019/2020 IRP Volume 2, the cost of building the first unit (F Class Frame CT) is estimated to be in 2019$, $173 million and the cost of the second unit would be $121 million if they are developed at the same time, thus the construction efficiencies translate into $52 million savings. When I reviewed how the second unit was modeled, I noted that in both Portfolios, the fixed costs that include the capital recovery (amortization) were about the same, in fact the fixed cost for the second unit in the Renewable + Flexible Gas Portfolio was 98% of the cost for the same unit in the Preferred Portfolio. However, if the second unit were to be built later, these construction efficiencies would not be realized and the difference between the portfolios would be smaller. This benefit from construction efficiencies is not reflected in the table above. This difference alone, if included in the above analysis, would reduce the differences between the Preferred Portfolio and the Renewable + Flexible Gas to about 1.5%. Another aspect that would reduce the difference between the Portfolios is that Renewable + Flexible Gas Portfolio supplies a smaller load as it has 1% Energy Efficiency 2024 – 2026 compared with the High Technology (0.75%) and that it includes the retirement of F.B. Culley 3 in 2033 – 2034. If these additional factors were included in the High Technology case, the difference would be smaller and in the order of 1%.

Building simultaneously the two turbines also minimizes the market capacity risks that as I elaborated earlier are substantial. It minimizes disturbance on the system as there would major work being carried out at A.B. Brown once, and it preserves the interconnection rights that CenterPoint Indiana South has at A.B. Brown. As I noted previously, the simple averaging I have presented assumes the risk of all different scenarios is equal. I will demonstrate some of these differences later in my testimony.

Q. Are there other approaches to evaluating the impact of the risk of choosing the wrong portfolio?

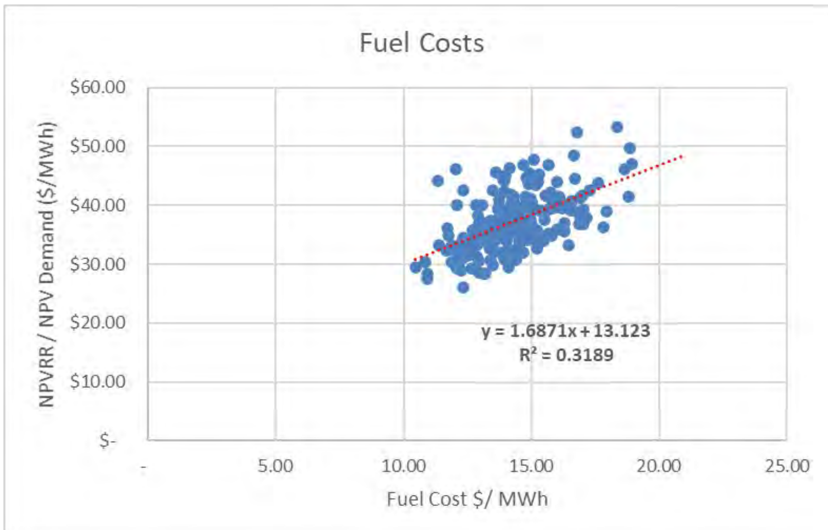
A. Yes. Another approach that I find useful is to identify the variables that most affect a Portfolio by reviewing the results of the Monte Carlo analysis. In this case, I look at how the average cost of the Portfolio under analysis changes as a function of uncertain variables. The Average Cost is determined by dividing the NPVRR by the NPV of the energy demand. I did this for the Preferred Portfolio and found that there is a clear correlation with the demand; higher demand to allocate the same fixed costs results in lower average costs per MWh, see first graph below that has on the X-axis the NPV of the Demand and the Y-axis the Average Cost. Also, there is a clear correlation with the Energy Cost (second graph) and with the Market Sales (third graph), as the first drives up the average cost up and second being an income rather than a cost. drives the average cost down. However, we note that changes in the fuel costs ($/MWh of NPV of Demand) are only weakly associated with changes in the Average Cost as can be noted in the fourth graph where we see a "blob" rather than a trend and we note the low R^2 (0.17) hence changes in fuel cost is not a significant risk for this Portfolio. I touched on this issue previously, when I evaluated the percentage of the NPVRR that was represented by fuel costs. But this analysis shows that the relatively limited risk of gas price volatility is fairly static: it correlates weakly with the portfolio costs.

Figure 3



To further illustrate this, I did the same exercise for the Portfolio where case where there is a small CCGT (433 MW) by 2026. This portfolio was expected to be still weakly correlated with the fuel prices but to a greater degree than the preferred portfolio as it has more fuel assets and this is shown in the figure below where we note an R^2 of 0.32, almost double that of the Preferred Scenario. So, for this gas conversion option, the risk of gas price is more closely correlated to the portfolio's average costs than the Preferred Portfolio and hence gas volatility has much greater impact.

Figure 4



Q. Are there other aspects that you would like to highlight about the decision to build the two CTs?

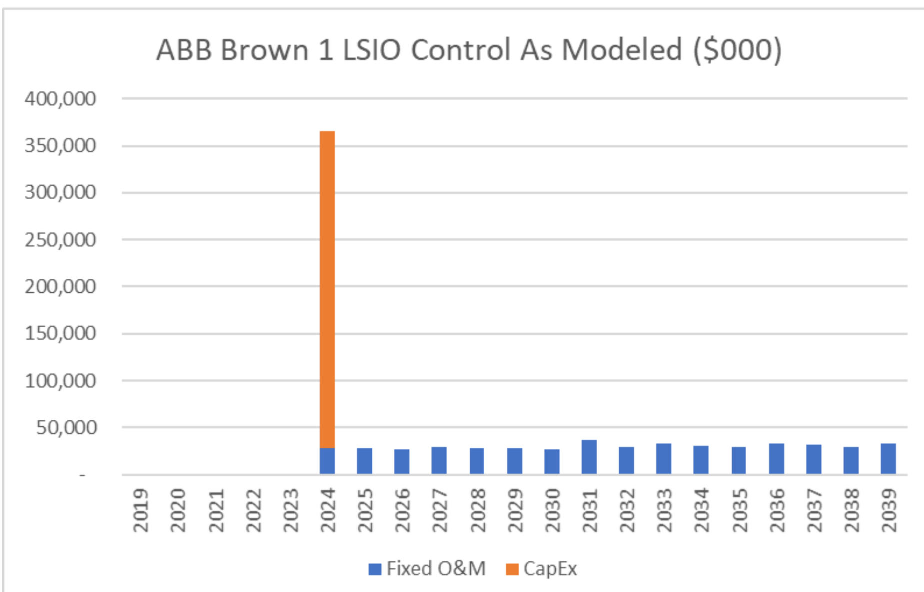
A. Yes, I find that the decision to build the two CTs adds flexibility to CenterPoint Indiana South's generation assets to deal with uncertainties that can affect demand growth or the future development of the CenterPoint Indiana South's and MISO's generation portfolio.

The CTs provide diversity in generation technologies and have option to be converted in the future.

Q. Let's focus for a moment on the analysis of continued operations of A.B. Brown with upgraded emissions controls in the IRP. Is it a fair criticism to claim that the analysis was biased against the continued operation as the analysis considering the capital cost concentrated in 2025 rather than amortized over the life of the asset?

A. No, I don't think it makes a difference at all and it was really the preference of the modeler. There is a time value of money and this works both ways in discounting for NPV calculations and for annualization of investments so it can be recovered over the life of the asset. We do this using the Capital Cost Recovery factor ("CCR") that multiplied by the capital investment of an asset converts it into a uniform stream of payments throughout the life of the asset. This was done for the capital investment of solar, wind and new generation offered to the model as candidates for selection. However, in the case of the A.B. Brown upgrades the modeler had the actual expected cashflow and modeled as such. This is shown in the figure below. The NPV of this cashflow stream is (2019) $401.2 million at a discount rate of 7.71% equal to the CEI South's weighted average cost of capital used in the IRP[23].

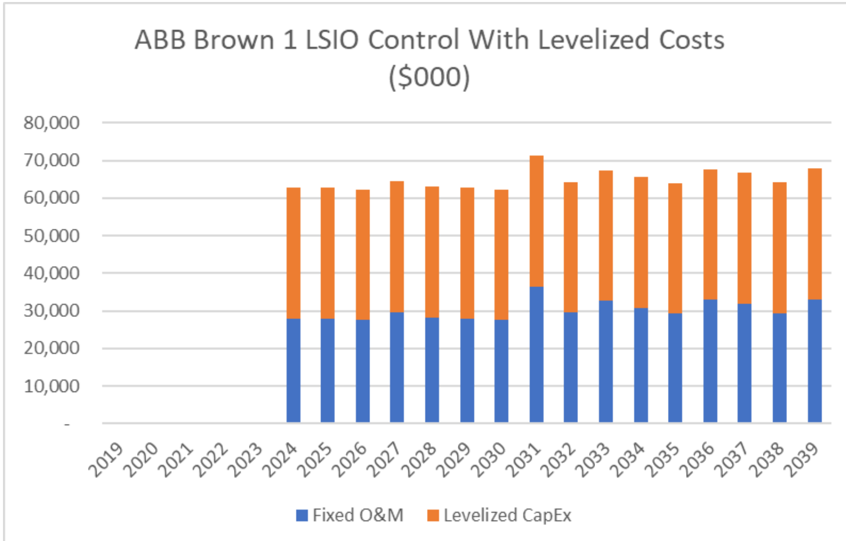
Figure 5



The analyst could have annualized the CapEx component above using the same discount rate above and 16 years amortization (the units would retire by the end of 2039) and produce a cashflow like the one below which has exactly the same NPV (2019) $401.2 million. Thus, there was no bias against the continuation of A.B. Brown, just the economics.

[23] See pg. 257 of Volume I of the CEI South 2019/2020 IRP.

Figure 6



Q **Should CenterPoint Indiana South have amortized the new CTs proposed in the Preferred Portfolio over a much shorter life?**

A. No, I don't think so. Even if in the future Indiana or the EPA were to adopt a net-zero policy as for example New York's CLCPA that requires the state's generation to be zero emissions by 2040[24], there is still a role for peaking generation like the CTs, which could be burning renewable natural gas ("RNG"), Green-Hydrogen or another net-zero emissions fuel. I was part of the team that conducted a study for the NY Research and Development Authority ("NYSERDA") to assess how the grid would evolve leading to a 100% emissions grid by 2040[25]. In the study we found that the optimal expansion plan was a mix of storage and thermal generation that by 2040 would use RNG at a cost of $23/MMBTU and subject to an availability limit of 32TBTU/year. We found that in the optimal plan there would be approximately 17,200 MW of thermal generation in the system, including some of the existing generation that did no retire and new CTs and combined cycle plants added as part of the expansion plan[26].

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[24] The New York Climate Leadership and Community Protection Act sets a goal of having a 100% emissions free electricity by 2040 (CLCPA) (see https://climate.ny.gov/-/media/CLCPA/Files/CLCPA-Fact-Sheet.pdf).
[25] See Appendix E: Zero Emissions Electric Gris in New York by 2040 https://brattlefiles.blob.core.windows.net/files/20842_initial_report_on_the_new_york_power_grid_study.pdf.
[26] See Table 4-1 of Appendix E referenced in the prior footnote.

For this reason, I don't think it is necessary or prudent to reduce the life of the assets as proposed.

Q As stated in "Response of CAC, Earthjustice, and Vote Solar to the Director's Draft Report for Vectren's 2019/2020 Integrated Resource Plan", do you agree that CenterPoint Indiana South's resource adequacy approach is inconsistent with the outcomes of MISO's policy change on the topic?

A. No, I don't think the changes in MISO policy will have a significant impact on the plans. Upon my review of the models, I appreciated that CenterPoint Indiana South made sure that the portfolios would likely meet both summer and winter requirements, and any seasonal requirement for that matter. Yes, as noted in CAC, et. al. response, CenterPoint Indiana South used the same PRMR of 8.8% of the MISO coincident peak across all months, however I don't expect that this approximation will result in the plans being inadequate as I illustrate below.

First, Aurora's optimization ensured that there were enough resources to meet the most stringent yearly condition, which as expected happened in August of each year. This is shown in the figures below for 2030 for the Renewable+ Peak Gas, Renewable 2030 and High Technology portfolio, where the peak demand and reserve requirements are compared with the available capacity from resources across the year. In these figures the red line is the CEI South's coincident demand, and the dashed line includes on top of that the minimum reserve (8.9%) that Aurora maintained over this demand. This is compared with the capacity contribution, i.e., the ELCC I mentioned earlier, of all the resources in the portfolio including market capacity purchases that add up to a blue line "Total Resources" in the graphs.

As can be observed in the graphs even though the ELCC of renewable dropped in late fall, winter, and early spring (see the reduction in the top green area representing the renewable and effect in Total Resources - blue line), this drop in Total Resources is more than compensated in by the concurrent drop in demand resulting in greater margins between the requirement (dotted line) and the availability (blue line). This is particularly clear for the Renewable + Flexible Gas and Renewable 2030, where we see that in August the dotted line and the blue line coincide, and "Capacity Market Purchases" were required

(red band) that in an "Annual" construct needs to be maintained throughout the year. A similar situation is observed for the Renewable 2030, where again we see that during August the available total resources (blue line) meet the requirements (dotted line) and capacity purchases are required. We also note that in winter the margin of the resources over the requirement is small. Finally, we see that for the High Technology case the available resources were always above this year requirements and no market capacity purchases were necessary.

Figure 7

Renewable + Flexible Gas Portfolio Demand, Reserves and Resources (MW).

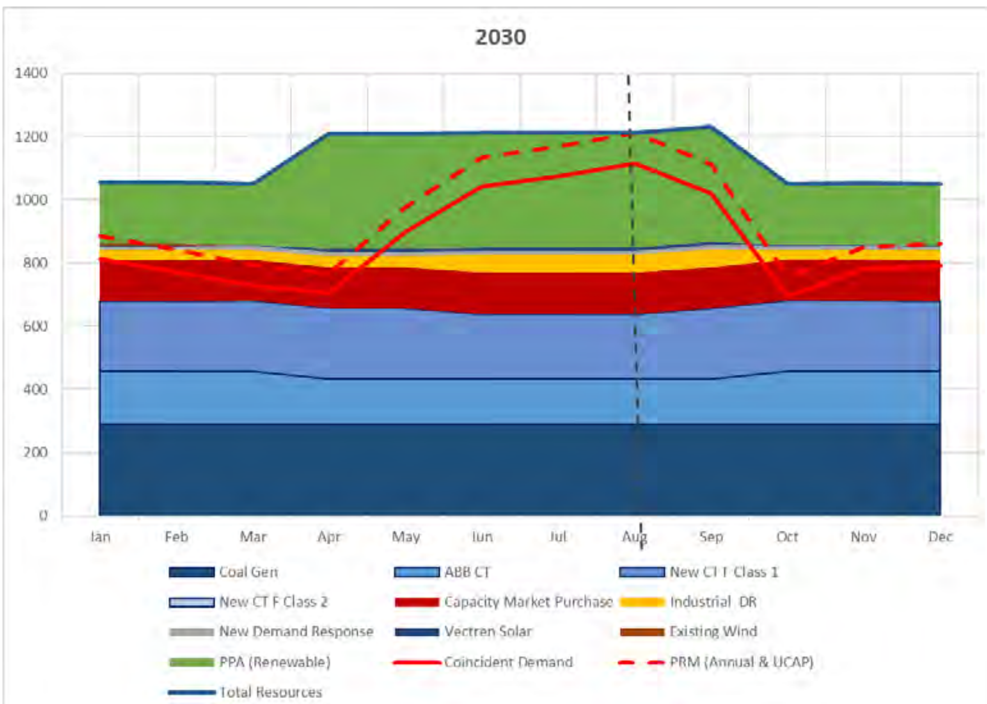


Figure 8

Renewable 2030 Demand, Reserves and Resources (MW).

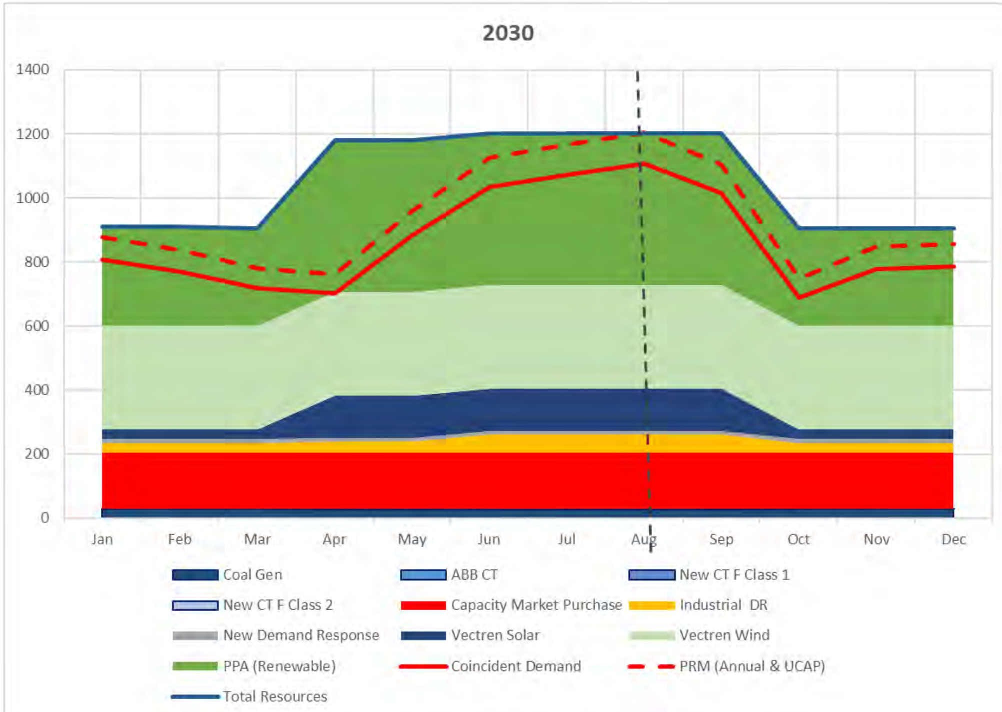
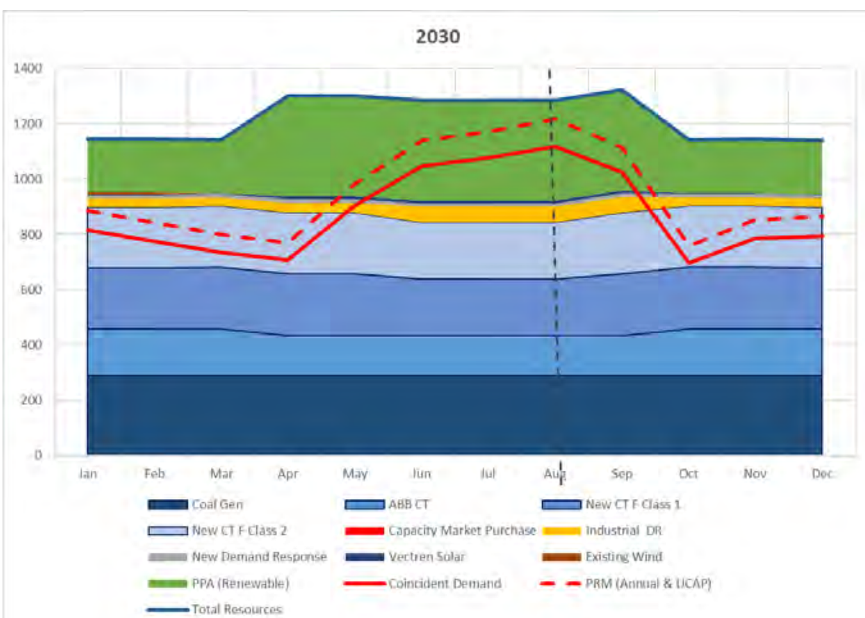


Figure 9

High Technology Portfolio Demand, Reserves and Resources (MW).



In summary, the August requirement defined the capacity needs of the portfolio and to meet it market capacity purchases are required on the Renewable + Peak and Renewables 2030 portfolio.

Q. Please continue with your response to the comment of CAC/Earthjustice and Vote Solar, do you think a MISO Seasonal Construct would have a major impact?

A. MISO has not yet defined what will be the final seasonal PRMR, however it is possible to illustrate how this may affect the Portfolios using the information shared by MISO on the "RAN Reliability Requirements and Sub-annual Construct"[27]. In MISO's document on page 23, the LRZ 6's Local Reliability Requirements ("LRR") (i.e., the amount of local resources to maintain an expectation that at maximum once every ten years there will not be enough resources to meet the load) are provided; and on page 31, the seasonal MISO wide PRMR% (UCAP) are also provided. On an annual basis for LRZ 6's and hence CEI South's, PRMR is given by the MISO System Wide PRMR. In MISO each LRZ needs to meet the largest of the MISO System-wide PRMR or a local reserve level called the Local Clearing Requirement (LCR), calculated as the Local Reliability Requirement less the LRZ's ability to import resources from MISO, which is given by the Zonal Import Ability (ZIA). Maintaining LRZ 6's Zonal Import Ability ("ZIA"), it is possible show that on a seasonal basis LRZ 6's PRMR should be given by the MISO System Wide PRMR, i.e., it is greater than LRZ 6's LCR. The figure below shows an illustrative impact of a MISO seasonal PRMR (UCAP based) of 7.1% in Summer, 18.5% for Winter, 22.3% for Spring and 13.8% for Fall for the 2030 demand and as before a comparison is made with the available resources. As can be observed the highest requirements occur in January, May, August, and September and are met by the available portfolio resources on those seasons. The only exception to the above is the Renewable 2030 for winter which may need to acquire a small amount of additional market capacity (~44 MW) to meet the requirement.

[27] RAN Reliability Requirements and Sub-annual Construct (misoenergy.org): https://cdn.misoenergy.org/20210203%20RASC%20Item%2004a%20Subannual%20Construct%20Presentation%20(RASC010,%20011,%20012)517859.pdf.

Figure 10

Renewable + Flexible Gas Portfolio Demand, Reserves and Resources (MW).

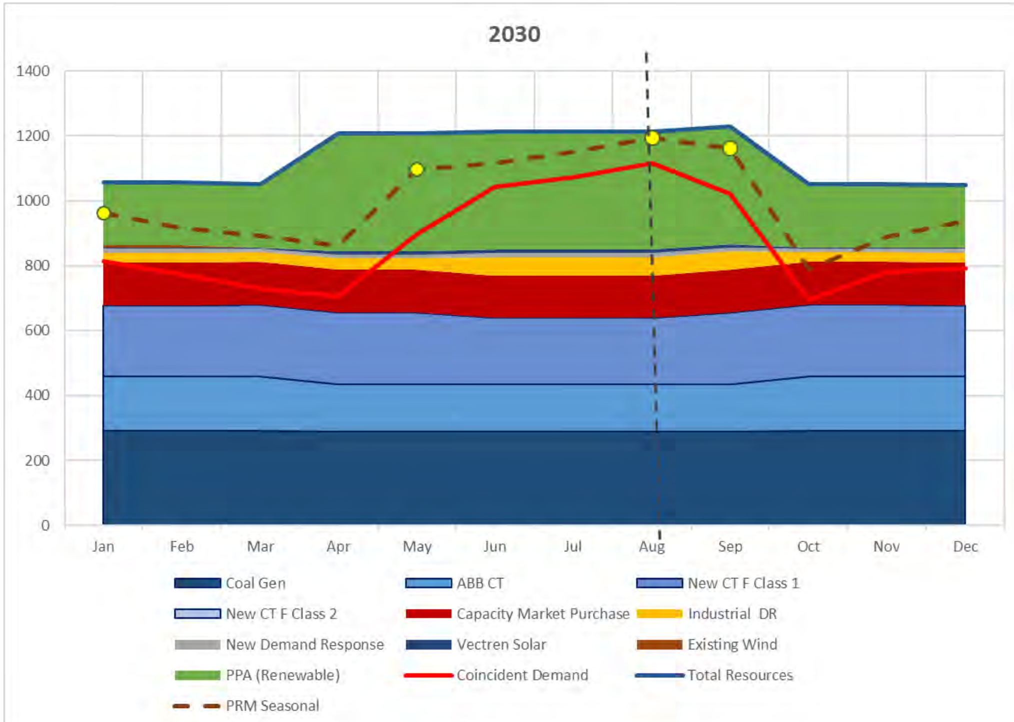


Figure 11

Renewable 2030 Demand, Reserves and Resources (MW).

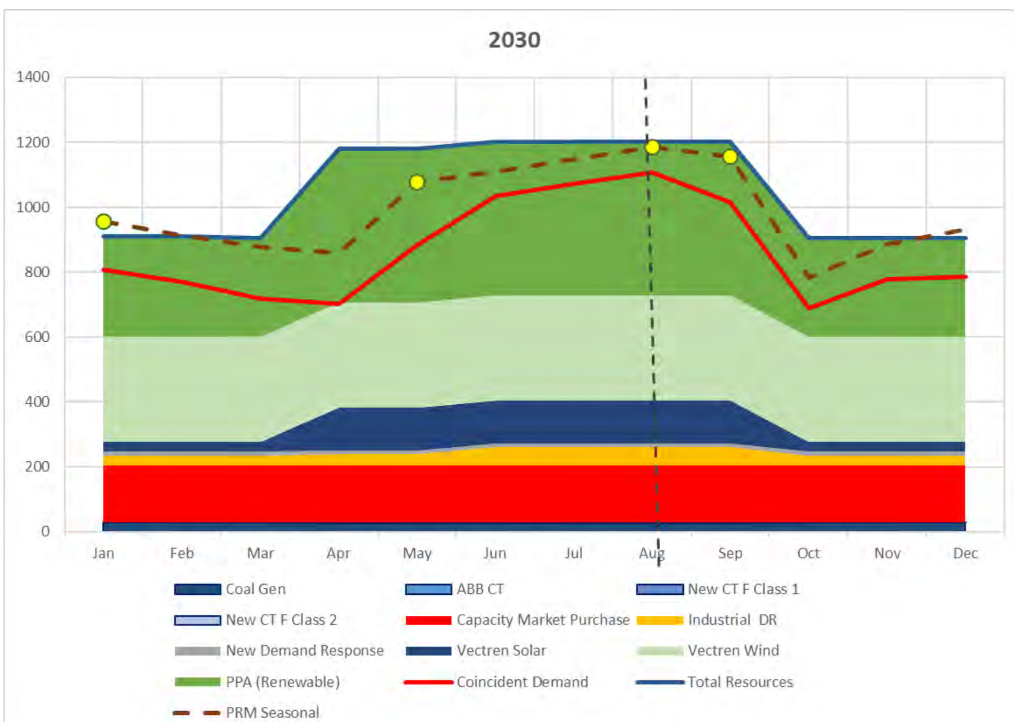
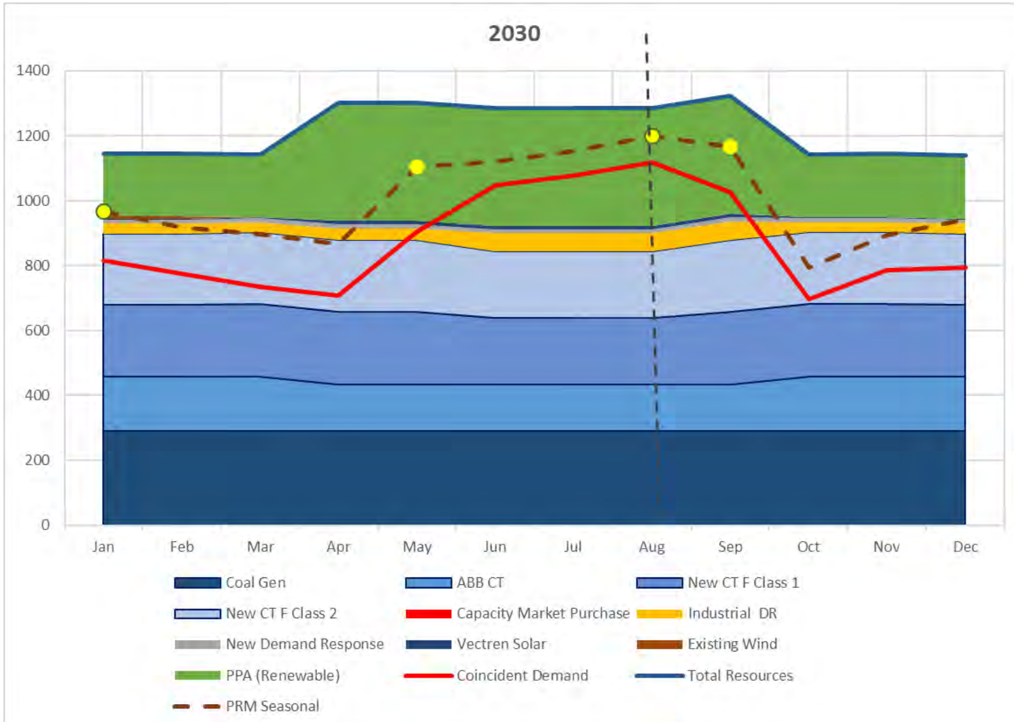


Figure 12

High Technology Portfolio Demand, Reserves and Resources (MW).



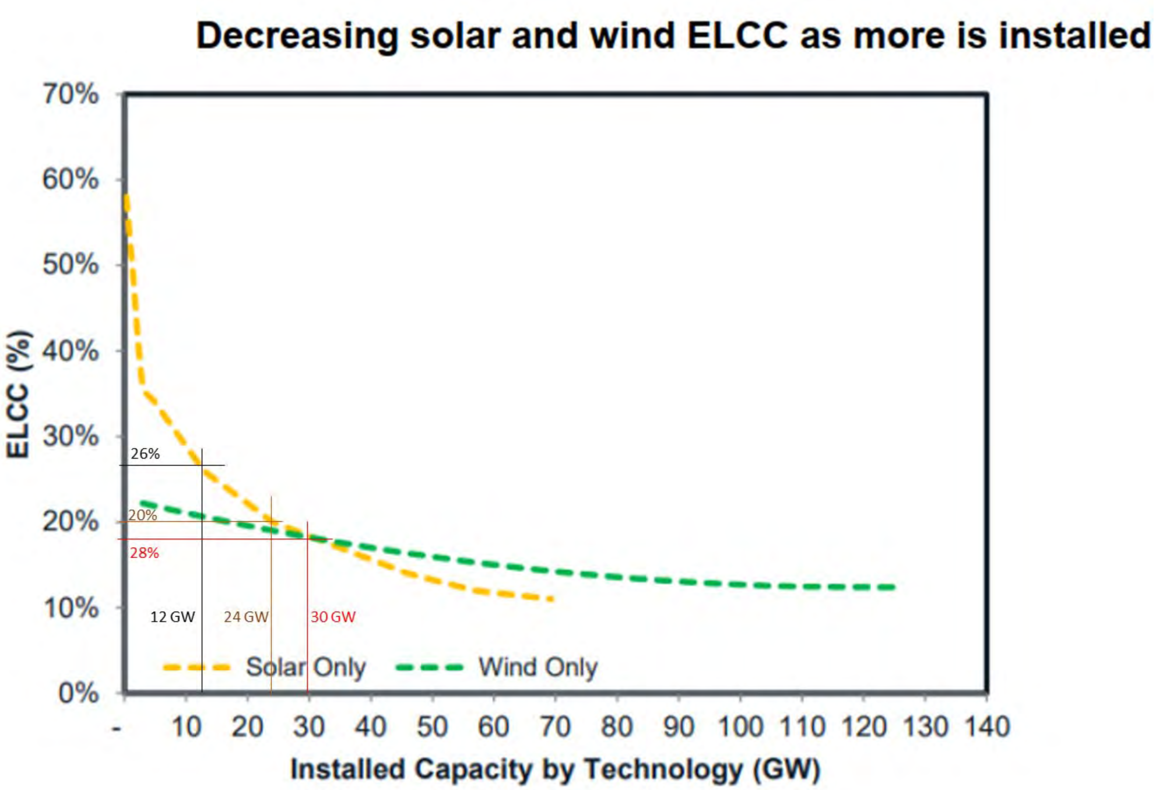
In summary the analysis above leads me to the conclusion that CenterPoint Indiana South's Preferred Portfolio as defined should fare well under a seasonal construct as well. Note again, the red band on Renewable + Flexible Gas and Renewables portfolios that show the capacity purchases, compared to the Preferred Portfolio.

Q As stated in "Response of CAC, Earthjustice, and Vote Solar to the Director's Draft Report for Vectren's 2019/2020 Integrated Resource Plan", do you agree that the ELCC of Solar and Wind is understated and if CenterPoint Indiana South had used more appropriate values only one CT would be necessary?

A. No, as I mentioned earlier the ELCC of renewable resources and storage decreases with the penetration and in this context, penetration is the amount of generation installed in the system as a whole, in this case MISO, not LRZ 6 or CEI South. For 2025 CenterPoint Indiana South used a ELCC for solar of 26% for summer and 6% for winter and reducing to 20% Summer and 4% winter for 2033, which is aligned with reasonable forecast of solar. As shown in Figure 5-5 of the IRP, derived from MISO´s Renewable Integration

Impact Assessment (RIAA) Assumptions Document and reproduced below[28], we see that MISO expects that solar will have an ELCC of 26% by the time the solar generation installed in its footprint reaches slightly over 12 GW and a value of 20% by the time the solar generation installed reaches slightly over 24 GW.

Figure 13



It is reasonable to expect that the higher rather than the lower forecast will materialize. By the end of 2020 MISO there were approximately 1,492 MW of solar generation in its footprint[29] and over 36 GW of solar in its interconnection queue[30]. Based on this alone it is reasonable to expect that by 2025 there will be more than 12 GW of solar in MISO's footprint and that by 2033 there should be 30 GW or more.

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[28] See MISO Renewable Integration Impact Assessment (RIIA) assumptions document V6, https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v7429759.pdf.
[29] Planning Year 2020-2021 Wind and Solar Capacity Credit (https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf).
[30] See MTEP 2020 pg. 23 https://cdn.misoenergy.org//MTEP20%20Full%20Report485662.pdf.

However, this is not the only evidence I see of the reasonableness of this assumption. MISO's Futures, which have the goal to provide bookends for the different generation technologies[31], forecast that for 2033 there will be a minimum of 7.2 GW of Solar on the pessimistic Limited Fleet Change ("LFC") Future, increasing to 13.5 GW of Solar in the Continued Fleet Change ("CFC") Future, 30.4 GW of Solar in the Accelerated Fleet Change ("AFC") Future, reaching a maximum of 42.7 GW in the Distributed and Emerging Technologies ("DET") Future. This is a quite wide range, but once combined with the status of the interconnection queue and the current tendency for an acceleration of solar generation as municipalities, states and utilities address the challenges of climate change; it stands to reason that the future solar generation should be more aligned with AFC or even the DET forecasts.

Hence and looking at the figure above we see that with 30 GW or more of solar in MISO's system a solar ELCC of 20% or lower is to be expected.

For winter, MISO currently uses a solar ELCC of 5%[32] and this will reduce as penetration increases.

Based on the above, I disagree with the statement that on the High Technology Portfolio there would be adequate reserves with only one CT. To illustrate this, I show below the gap between the Total Resources (blue curve) and capacity needs (dotted brown curve) for 2033 using the illustrative seasonal PRMR. As can be observed there are gaps across all seasons.

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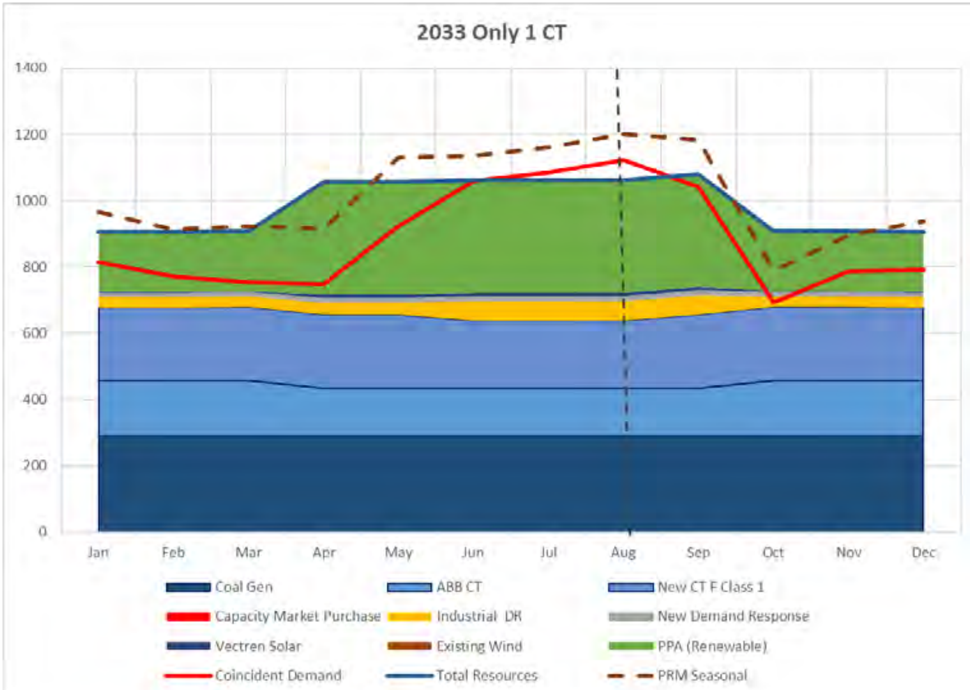
[31] See MTEP 2020 pg. 28 https://cdn.misoenergy.org//MTEP20%20Full%20Report485662.pdf.
[32] See page 24 of MISO RAN Reliability Requirements and Sub-annual Construct (misoenergy.org): https://cdn.misoenergy.org/20210203%20RASC%20Item%2004a%20Subannual%20Construct%20Presentation%20(RASC010,%20011,%20012)517859.pdf.

Figure 14

High Technology Portfolio Demand, Reserves and Resources (MW); 2033 with One CT.



III. CONCLUSION

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, at the present time.

agreement and associated negotiated rate letter agreement; (iv) Zone 3-3 Summer No-Notice ("3-3 SNS") service agreement and associated negotiated rate letter agreement; and (v) Firm Lateral Service ("FLS-FT") service agreement and associated negotiated rate letter agreement (collectively the "Firm Agreements").

Q. What is the primary term of the agreement?

A. The primary term of the Firm Agreements shall be effective beginning upon the first day of the month following the date on which TGT's Project is capable of delivering the Maximum Contract Quantities from Petitioner's Primary Receipt Points to Petitioner's Primary Delivery Points and the Project has been placed into service, as determined in TGT's sole discretion ("Service Commencement Date") and shall continue in full force and effect for a primary term of twenty (20) years.

III. GAS TRANSPORTATION AND LATERAL OPTIONS

Q. Please describe the process that CenterPoint Indiana South undertook to engage pipeline companies and the desired pipeline services.

A. Through an informal Request for Proposal ("RFP"), CenterPoint Indiana South engaged pipeline companies seeking proposals for the following desired pipeline services:

- Desire to replace coal-fired power plant with a natural gas turbine power plant.
- May require new pipeline construction if upstream pipeline does not have available capacity.
- Need quick start up options (20 minutes or less) and non-ratable gas flow options.
- No-Notice firm supply is highly desired since no nomination is needed for quick start up.
- Diverse Supply – ability to provide flexible receipt points from both the North and South on pipeline system.
- Long term agreement – 20 years.
- Firm mainline capacity to meet full requirements up to 5,417 MMBTU/hour.
- Ability to finish build out with first flow in early 2024.

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- Long term agreement – 20 years.
- Firm mainline capacity to meet full requirements up to 5,417 MMBTU/hour.
- Ability to finish build out with first flow in early 2024.

VERIFICATION

I, Matthew A. Rice, Director of Indiana Electric Regulatory and Rates for Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South, under the penalty of perjury, affirm that the answers in the foregoing Direct Testimony are true to the best of my knowledge, information and belief.

Matthew A. Rice
Director of Indiana Electric Regulatory and Rates