FILED
January 22, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH") FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE GAS TURBINE GENERATION FACILITY ("CCGT"); (2) APPROVAL OF ASSOCIATED RATEMAKING AND ACCOUNTING TREATMENT; (3) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR COMPLIANCE PROJECTS TO MEET FEDERALLY MANDATED REQUIREMENTS ("CULLEY 3 COMPLIANCE PROJECT"); (4) AUTHORITY TO TIMELY RECOVER 80% OF THE COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CULLEY 3 COMPLIANCE PROJECTS THROUGH VECTREN SOUTH'S ENVIRONMENTAL COST ADJUSTMENT MECHANISM; (5) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE REVENUE REQUIREMENT FOR COSTS, INCLUDING CAPITAL, OPERATING, MAINTENANCE, DEPRECIATION, TAX AND FINANCING COSTS ON THE CULLEY 3 COMPLIANCE PROJECT WITH CARRYING COSTS AND (B) POST-IN-SERVICE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE CCGT AND CULLEY 3 COMPLIANCE PROJECT UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; (6) ONGOING REVIEW OF THE CCGT; (7) AUTHORITY TO IMPLEMENT A PERIODIC RATE ADJUSTMENT MECHANISM FOR RECOVERY OF COSTS DEFERRED IN ACCORDANCE WITH THE ORDER IN CAUSE NO. 44446; AND (8) AUTHORITY TO ESTABLISH DEPRECIATION RATES FOR THE CCGT AND CULLEY 3 COMPLIANCE PROJECT ALL UNDER IND. CODE §§ 8-1-2-6.7, 8-1-2-23, 8-1-8.4-1 *ET SEQ*, 8-1-8.5-1 *ET SEQ.*, AND 8-1-8.8 -1 *ET SEQ.*	)	**CAUSE NO. 45052**

<u>ORDER OF THE COMMISSION</u>

Presiding Officers:
David E. Ziegner, Commissioner
David Veleta, Administrative Law Judge

On February 20, 2018, Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South" or "the Company") filed its verified petition in this Cause seeking, among other relief, certificates of public convenience and necessity for a new duct-fired F-class 2x1 combined cycle combustion turbine ("CCGT") providing 700 MW of baseload and 150 MW of peaking capacity pursuant to Ind. Code ch. 8-1-8.5 and for certain environmental projects at its Culley Unit 3 generating station pursuant to Ind. Code ch. 8-1-8.4. We convened a prehearing conference on April 3, 2018, and issued a prehearing conference order on April 11, 2018. Petitions to intervene were filed by (1) the Vectren Industrial Group; (2) Valley Watch, Inc., the Citizens Action Coalition of Indiana, Inc., and the Sierra Club ("Joint Intervenors"); (3) the Indiana Coal Council, Inc. ("ICC"), Sunrise Coal, and Alliance Coal, LLC (the "Coal Parties"); (4) SABIC Innovative Plastics Mt. Vernon, LLC, St. Joseph Energy Center, LLP, St. Joseph Phase II LLC, and Evansville Western Railway. All of these petitions to intervene were subsequently granted. A public field hearing was held in Evansville on July 11, 2018, at which time members of the public presented testimony. An evidentiary hearing was commenced on October 9, 2018, at which time evidence was offered by Vectren South, the Office of Utility Consumer Counselor ("OUCC"), the Joint Intervenors, the Vectren Industrial Group, and the Coal Parties. Thereafter, Vectren South presented its rebuttal evidence. The Commission, having heard the evidence and being duly advised, now finds as follows:

1. Notice and Jurisdiction. Due legal and timely notice of the prehearing conference, public field hearing, and evidentiary hearing in this Cause was given and published as required by law. Petitioner is a "public utility" as defined in Ind. Code § 8-1-2-1(a) and Ind. Code § 8-1-8.5-1, an "energy utility" as defined in Ind. Code § 8-1-8.4-3, and an "eligible business" as defined in Ind. Code § 8-1-8.8-6. Petitioner is subject to the jurisdiction of this Commission in the manner and to the extent provided by Indiana law. Pursuant to Ind. Code chs. 8-1-8.5 and 8-1-8.4, Petitioner may seek Commission approval of Certificates of Public Convenience and Necessity pursuant to the chapters. Accordingly, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding in the manner and to the extent provided by laws of the State of Indiana.

2. Petitioner's Characteristics and System. Petitioner is an operating public utility incorporated under the laws of the State of Indiana, with its principal office and place of business in the City of Evansville. Petitioner provides electric and gas utility service to the public in Indiana and is subject to the regulation by this Commission in the manner and to the extent provided by the laws of the State of Indiana. This proceeding pertains to Petitioner's electric utility business. Petitioner renders retail electric utility service to approximately 145,000 customers in seven counties in southwestern Indiana, and owns, operates, manages and controls electric generating, transmission and distribution plant, property and equipment and related facilities which are used and useful for the convenience of the public in the production, transmission, delivery and furnishing of electric energy, heat, light and power for residential, commercial, industrial and municipal uses. Petitioner furnishes such electric utility service to retail customers located in

Vanderburgh, Posey, Gibson, Pike, Warrick, Dubois and Spencer Counties, with a major portion of such customers residing in and around the City of Evansville, Indiana. Vectren South owns and operates 1,248 megawatts ("MW") of total net generating capacity. This generation capacity is primarily derived from the following five (5) coal-fired baseload units providing a total of approximately 1,000 MW: A.B. Brown 1 (245 MW), A.B. Brown 2 (245 MW), F.B. Culley 2 (90 MW), F.B. Culley 3 (270 MW) and Warrick 4 (150 MW[1]). Petitioner procures 100% of its coal supply from mines located in Indiana.

Vectren South's operations are subject to federal, state and local rules promulgated by, among others, the federal Environmental Protection Agency ("EPA"), the Indiana Department of Environmental Management ("IDEM") and by the Environmental Rules Board of the State of Indiana. Such rules establish environmental compliance standards that govern emissions and discharges from Vectren South's electric generating units.

3. Background. Vectren South Chairman, President and Chief Executive Officer Carl L. Chapman provided an overview of the relief requested. Due to conditions generally facing the electric industry, baseload generation resources are in transition in Indiana and throughout the Midcontinent Independent System Operator ("MISO") region. This is reflected in MISO's recent resource forecast that shows the continued widespread retirement of coal units by the end of 2023 and the move to gas and renewable resources. The IURC Director's Report for the 2016 Integrated Resource Plans noted the anticipated change in the state's resource mix, in part due to the age of coal units, long-term projections for low cost gas supplies, environmental policies driving emission reductions, and declining cost of renewable resources.

In conducting its 2016 Integrated Resource Plan ("IRP"), Vectren South has evaluated the age and condition of its generation fleet, as well as the operational characteristics of the units and resulting inability to dispatch them effectively into the MISO market. Vectren South has further evaluated the impact of environmental regulations on the need for incremental investment to continue to operate these units to serve its customers. This analysis also considered the efficiency of competing technology and the forecast for gas prices. The 2016 IRP results were updated in 2017 (the "2017 Update"). Mr. Chapman described that the 2016 IRP as supplemented by the 2017 Update led the Company to seek in this Cause what is in effect three different certificates of public convenience and necessity ("CPCN"), two of which are in the alternative. Vectren South's proposal is designed to ensure that after the retirement of baseload units, the Company will have baseload capacity sufficient to meet MISO Planning Reserve Margin ("PRM") requirements reliably and serve customers, which will limit exposure to market volatility and congestion costs associated with reliance on off-system resources. First, the Company seeks a CPCN pursuant to Indiana Code ch. 8-1-8.5 for a duct-fired 2x1 F-class combined cycle combustion turbine ("CCGT") that will provide 700 MW of baseload capacity and, because it is duct-fired, 150 MW of peaking capacity. This CCGT will be located at the Brown site adjacent to the existing units, which will be retired. Second, In the alternative to that request, the Company seeks a CPCN for the unfired 2x1 F-class CCGT that will provide 700 MW of baseload capacity and no peaking capacity. Under this alternative scenario, the CCGT will be identical to the first alternative except that it will not be duct-fired. Finally, the Company seeks a CPCN pursuant to Ind. Code ch. 8-1-8.4 for a federally mandated project needed to comply with Coal Combustion Residuals ("CCR")

[1] Represents Petitioner's ½ interest in Warrick 4, a 300 MW unit.

and Effluent Limit Guidelines ("ELG") regulations and thereby keep Culley Unit 3 in service beyond 2023. Culley 3 was selected as the coal unit having the best heat rate, environmental controls and operating history compared to the other existing units. Under this plan, at the end of 2023, the Brown Units, Culley Unit 2 and Warrick Unit 4 would be retired. In addition to the CPCNs, the Company seeks to begin to recover for federally mandated improvements that were approved in Cause No. 44446.

4. <u>Overview of the Evidence.</u>

A. <u>Condition of Current Fleet and Need for Decision</u>.

i. <u>Vectren South</u>. The main drivers behind Vectren South's proposal are the age and operating characteristics of Vectren South's existing baseload capacity and the upcoming deadlines for significant capital investments to address environmental regulations. Mr. Wayne D. Games, Vice President of Power Supply at Vectren South, testified regarding the condition of Vectren South's current generation fleet and the challenges facing the fleet. He testified Vectren South's fleet consists of five (5) coal-fired baseload units totaling 1,000 MW. Mr. Games further testified that growth of renewable energy sources and low natural gas prices have negatively affected MISO's dispatch of Vectren South's coal-fired units. Instead of running continuously, Vectren South's units are now cycled up and down throughout the day, or are shut down altogether, decreasing unit efficiency and increasing wear and tear on the units. Mr. Games testified that because the units were not designed to cycle in this manner, the units cannot effectively compete with gas units in particular, which have far better operating flexibility. Continued market reforms are exacerbating this issue and jeopardizing unit availability and reliability.

Mr. Games also explained that the individual units face additional operating challenges. In particular, the Brown Units rely on scrubbers that utilize a technology that has been abandoned by the industry because of its high variable costs and the vapor it emits which causes corrosion of the unit structure. The scrubbers are already past their expected 30 year design life and present a significant risk to reliability and maintenance costs. He explained that Culley Unit 2 is Vectren South's oldest and smallest unit and that it has the worst heat rate of any coal unit in the state. Finally, he explained the unique circumstances related to the joint operation of the Warrick unit which creates uncertainty as to the duration of its operation.

Ms. Angila Retherford, Vice President of Environmental Affairs and Corporate Sustainability, testified regarding two new major federal regulatory initiatives – ELG and CCR - impacting Vectren South's coal-generating units. Absent substantial investment at all of Vectren South's coal plants, they must cease operations by December 31, 2023. Ms. Retherford described Vectren South's environmental compliance strategy for the Brown and Culley units and testified future compliance costs were modeled in Vectren South's 2016 IRP under the business as usual scenario. Ms. Retherford testified these rules and other existing federal regulatory requirements will require Vectren South to make significant further investment at the Brown and Culley generating facilities to continue their operation. While uncertainty exists regarding the future regulation of carbon emissions, a significant benefit of Vectren South's proposed resource plan is the 60% reduction of carbon emissions by 2024.

ii. The Opposing Parties. While the specific evidence of each of the parties is set forth below, in general, with the exception of the Industrial Group, the other parties submitted testimony that advocated delay in making decisions related to unit retirements.

(a) OUCC. OUCC witnesses Lauren M. Aguilar – Utility Analyst, Anthony A. Alvarez – Utility Analyst and Peter M. Boerger – Senior Utility Analyst testified regarding Vectren South's request for a CPCN to construct the CCGT. These OUCC witnesses testified Vectren South's decision to construct the CCGT is premature because Vectren South has not explored all practical alternatives to extend the life of the A.B. Brown units. OUCC Witness Aguilar ultimately recommended that the decision to build the CCGT be delayed until the end of the 2019 IRP process, in order to allow Vectren South the opportunity to evaluate additional alternatives. The OUCC offered no alternative resource proposal, but argued for a "blended approach" with the possible continued use of existing assets, and suggested that the necessary expenditures to continue use of these assets could be viewed as buying an "option on the future." The OUCC witnesses asserted that deferring any decision until the conclusion of the 2019 IRP process would still allow sufficient time to take action without affecting reliability.

(b) Coal Parties. The Coal Parties' witnesses generally testified that Vectren South should wait to transition its baseload generation from coal to natural gas because the environmental regulations driving the transition, the ELG and CCR rules, are in flux and not yet final. Specifically, the Coal Parties' witnesses testified that recent and anticipated EPA reconsiderations of the ELG and CCR regulations, as well as the potential stay or replacement of the Clean Power Plan ("CPP"), create the potential scenario where Vectren South could operate the Brown and Culley units beyond 2023 without the need to make material investments in compliance measures. Coal Parties witness Michael J. Nasi – Partner with the law firm of Jackson Walker L.L.P. – further testified that Vectren South's decision to retire its coal plants is premature. He recommended that the decision be delayed until the environmental regulations driving the decision are better understood. With respect to the Brown units, the Coal Parties suggested that Vectren should investigate an alternative scrubber technology marketed by a Chinese firm to replace the existing dual alkali scrubbers. This technology which uses ammonia creates material that can be sold as fertilizer with revenues used to offset variable operating costs of the scrubber.

iii. Vectren South Rebuttal. Ms. Retherford, who is also a licensed attorney, testified regarding the risks associated with continuing to operate Vectren South's coal-fired fleet and delaying the decision to construct the proposed CCGT. Ms. Retherford testified that recent legal developments related to the CCR rule have made it impossible for Vectren South to continue operating its coal-fired fleet beyond 2023 without significant capital investment. She testified that the current water discharge permits require, and the groundwater monitoring results at the Brown and Culley ash ponds confirm, that Vectren South must cease discharging coal ash by December 31, 2023, pursuant to the ELG and CCR rules. She also testified that *Utility Solid Waste Activities Group v. Environmental Protection Agency*, 901 F.3d 414 (D.C. Cir. 2018), 2018 U.S. App. LEXIS 23547, confirms that the CCR Rule is final, including the final compliance deadlines at issue in this proceeding. Ms. Retherford testified that pond retirement delay is not an option, and therefore Vectren South must either make investments to comply with the CCR rule or retire the plants before 2024.

In response to the Coal Parties' position that the current administration could alleviate environmental carbon regulations applicable to the coal units, Ms. Retherford testified that the Administration's proposed replacement for CPP does not alleviate the problems. On August 31, 2018, the EPA published its proposed Affordable Clean Energy ("ACE") rule in lieu of CPP. She explained that ACE would increase uncertainty and could actually increase the cost of compliance. For units with high heat rates – such as Brown – ACE would cause significant future compliance costs. Petitioner's Exhibit No. 9-R, pp. 31-40.

Vectren South also presented the testimony of Richard McMahon from Edison Electric Institute ("EEI") regarding the growing importance of Environmental, Sustainability and Governance ("ESG") reporting and metrics to the financial community, and the focus of all public electric utilities on being responsive to these topics and establishing explicit carbon reduction targets as part of their public disclosures. Mr. McMahon described the coordinated electric industry response to the demands for ESG reporting, and provided specific examples of lenders and large institutional investors who are putting pressure on companies to transition from dependence on coal units. He explained that Vectren South's 60% carbon emission reduction was in line with similar targets publicly disclosed by its electric utility peers. He also presented information regarding the industry transition from reliance on coal to use of gas as part of the ability to reduce carbon emissions.

As to the potential for alternative scrubbers, Vectren South witness Paul Farber – Principal of P. Farber & Associates, LLC – testified regarding the shortcomings of the technologies presented by Sunrise Coal witness Dombrowski and OUCC witness Aguilar and explained why, from an operational and financial perspective, it would not be prudent for Vectren South to adopt those technologies. With respect to the ammonia based scrubber technology presented by witness Dombrowski, Mr. Farber testified the technology has very limited deployment in the United States and would present a number of operational challenges if installed at baseload coal-fired units like A.B. Brown. These uncertainties and risks posed by adoption of this technology include its cost, its impact on operation of the units (including that it might cause Vectren South to be out of compliance with regulations for other constituents such as mercury and particulate matter absent further types of investments), the unknown ability to sell fertilizer output, and the complications associated with dealing with vendors with no domestic history. He discussed in depth the substantial operational burden and health and Homeland Security risk associated with handling the large amount of ammonia required by such a scrubber. Mr. Farber concluded that the Coal Parties had failed to provide any evidence that the capital costs of this scrubber technology would be any less than the scrubber modeled in Vectren South's 2017 IRP Update. In rebuttal testimony, Jon K. Luttrell, Senior Vice President, Utility Operations and President of Vectren Utility Holdings, Inc., also discussed the cyber security complications and risks posed by adoption of Chinese scrubber technology.

Mr. Farber also responded to OUCC witness Aguilar's criticism that Vectren South "only" evaluated wet limestone and her presentation of potential costs for other technologies. Mr. Farber testified that dry scrubbing is not an applicable technology at A.B. Brown for technical and economic reasons, and therefore it was logical for Vectren South to evaluate wet limestone technology at A.B. Brown. He also testified the cost estimates presented by Ms. Aguilar are not comparable cost estimates to replace the existing scrubbers at Brown Units 1 and 2.

Mr. Games testified on rebuttal that there simply is no time to delay a decision and await the outcome of another IRP. The Vectren South coal units must be retired or retrofitted by December 31, 2023. Given that there has been nothing to suggest more delay would change the overall economics that the F-class 2x1 CCGT is part of the lowest cost solution under every scenario, there is no reason to believe that modeling in the next IRP would change that result. Mr. Games provided an exhibit setting forth a timeline showing that a delay to allow the next IRP to proceed would leave Vectren South with essentially no baseload capacity for almost three years. Petitioner's Exhibit No. 4-R, Attachment WDG-3R. During that entire period, Vectren South customers would be completely exposed to the market for capacity and energy. Per the redirect examination of Justin M. Joiner, Director of Regulatory Policy and MISO Affairs for Vectren Utility Holdsings, Inc. ("VUHI"), this would be during the period when MISO is projecting its largest capacity shortfall for Zone 6 (Indiana). Tr., p. J-19. The Commission's Director's Report states "[a]n appropriate planning aspiration is to maintain flexibility while also waiting as long as reasonably possible to commit to a resource." Joint Intervenors' Exhibit 2, Attachment TFC-6, p. 49. Mr. Games testified on cross-examination that Vectren South has waited as long as reasonably possible. Tr., p. E-47.

B. Modeling and Results.

Only two parties presented modeling evidence and results. Vectren South presented the modeling from the 2017 Update and the 2016 IRP. Sunrise Coal Witness Philip Hayet presented alternative modeling whereby Vectren South's Preferred Portfolio was delayed by seven years in order to allow existing coal units to continue to operate beyond 2023. Other parties offered criticism of Vectren South's modeling but presented no alternative modeling.

i. 2016 IRP.

Vectren South's case was filed in the context of a proposed new rule to govern the IRP process. While our new rule was not effective during the 2016 IRPs, all participating electric utilities complied. This new process is significantly more transparent. It includes the participation of stakeholders, the convening of public meetings, and the submission of and response to comments. Mr. Matt Rice, Director – Research and Energy Technologies, testified regarding Vectren South's IRP process and the results of that process. Mr. Rice described Vectren's approach to its 2016 IRP process and testified the Company engaged several industry experts, including Burns & McDonnell and Pace Global, to conduct technical modeling. Mr. Rice testified Vectren South worked with these experts and IRP stakeholders to conduct scenario analysis to evaluate fifteen portfolios, each representing a different mix of supply and demand side resources to meet customer load over a 20-year time horizon. He further testified Vectren South worked with Pace Global to conduct a risk analysis and evaluate the fifteen portfolios using a balanced scorecard approach. From this analysis, the Company identified the "preferred portfolio" which consisted of replacing all existing coal fired generation other than Culley Unit 3 as well as gas peaking units Northeast 1 and 2 and Broadway 1 by 2024 with an F-class .05 Fired CCGT. Mr. Rice testified the Company incorporated stakeholder input throughout the process and described the steps Vectren South took to engage stakeholders both before and during the process. This engagement included having stakeholders develop two portfolios which were then modeled and included in the risk analysis.

Mr. Matthew Lind – Associate Project Manager, Burns & McDonnell – described the modeling Burns & McDonnell conducted in the 2016 IRP on behalf of Vectren South to evaluate its resource needs over the next twenty years. He testified the results of Burns & McDonnell's modeling identified a low-cost portfolio that ceased coal operations at Vectren South's coal fired facilities (A.B. Brown Units 1 and 2, F.B. Culley Units 2 and 3, and Warrick Unit 4) and replaced this capacity and energy with the combined cycle facility proposed here along with a simple cycle facility. Mr. Gary Vicinus – Managing Director for Utilities at Pace Global – described Pace Global's role in identifying and defining the objectives, metrics and risks in order to select the preferred portfolio among the many options. He testified Pace Global used a balanced scorecard approach to apply a risk analysis to a selection of portfolios ultimately to recommend a preferred portfolio. Mr. Vicinus further testified regarding revisions Pace Global made to its risk analysis and explained that, even with these revisions, the risk analysis indicated the preferred portfolio was the best approach.

We received the 2016 IRP into evidence. We also received comments from the Joint Intervenors as well as the Draft and Final Director's Report. Thirty-six different technologies (representing an assortment of renewables, storage, natural gas, and coal) were modeled and screened on equal footing using a busbar, or levelized cost of electricity, comparison, and then a Strategist portfolio optimization. Petitioner's Exhibit No. 5, Attachment MAR-1, pp. 79 and 166. Fifteen different portfolios emerged from this iterative process as potential solutions. *Id*., p. 81. Some portfolios included a CCGT; some did not. Some continued reliance on coal; some abandoned coal. Varying degrees of renewables and storage were included. Two stakeholder portfolios were modeled. Out of this modeling, the optimal portfolio in terms of cost was a switch to nearly all gas, with the fired F-class 2x1 CCGT serving as the foundation of the "heavy gas" portfolio." *Id*., p. 82. Under every scenario (base and large load, high and low regulatory, high and low economics, high technology), the modeling always produced the lowest cost portfolio solution (i.e., optimal) as including the fired 2x1 F-class CCGT. *Id*., pp. 204-210.

Mr. Rice described the preferred portfolio and explained why it ranked the best on the balanced scorecard. He testified it performed the best because the portfolio is diversified as it contemplates keeping FB Culley 3 (a coal unit) and existing wind contracts, building a CCGT and introducing solar and continuing to offer energy efficiency. He further testified it is among the lower cost portfolios (within 4% of the predominantly gas lowest cost portfolio) and ultimately performed best overall when viewed across multiple measures on the balanced scorecard. Because the all-gas portfolio represented the lowest cost portfolio, it is the retention of Culley Unit 3 and the accelerated addition of the 50 MW solar project that increases the costs of the Preferred Portfolio over the lowest cost all-gas portfolio. Retention of coal and the addition of solar are essential to diversity.

ii. 2017 Update.

Mr. Lind testified Vectren South requested Burns & McDonnell to update the 2016 IRP modeling and the re-evaluated low-cost portfolio was consistent with the low-cost portfolio identified in the 2016 IRP. He explained that several modeling inputs were updated, including the capital cost for solar resources, variable production costs and revenue requirements for existing units, an assumed operation of Warrick Unit 4 through 2023, and updated cost assumptions for capacity, energy, natural gas, coal, and energy efficiency. Petitioner's Exhibit No. 6, pp. 9-10.

OUCC witness Peter Boerger testified regarding Vectren South's 2017 Update economic modeling. Mr. Boerger testified that Vectren South's 2017 Update did not adequately consider viable options for serving its customers—including making use of existing resources and adequately considering the addition of a smaller CCGT unit rather than the 2x1 unit being proposed. Mr. Boerger also testified Vectren South's modeling of the proposed CCGT understated its capital cost by $200 million, an error which disadvantaged other options in Vectren South's modeling. Mr. Boerger ultimately recommended Vectren South reevaluate its future needs and model additional alternatives.

CAC witness Tyler Comings – Senior Researcher at Applied Economics Clinic – testified on behalf of the Joint Intervenors. Mr. Comings criticized Vectren South's modeling, testifying it was too convoluted to yield a sufficiently transparent or credible result. He testified Vectren South used too many models in the selection of the preferred portfolio and that the use of many models created ample opportunity for flawed and/or inconsistent input assumptions and other settings that could create bias in favor of the preferred plan. Mr. Comings ultimately recommended Vectren South's petition be denied because, in his view, the Company did not provide sufficient justification for its choice to build the CCGT and continue the operation of Culley 3.

Indiana Coal Council witness Emily Medine – Principal in the consulting firm of Energy Venture Analysis, Inc. – also testified regarding Vectren South's modeling. Witness Medine testified Vectren South should have fully updated its 2016 IRP analysis, including its scenario analysis, in order to confirm its preferred resource portfolio. She further testified that such an update should include a broader analysis (including sensitivity analyses) of the relevant assumptions and factors as of a time as close to Vectren South filing its Petition as possible. Ms. Medine attributed the decision to build a CCGT to financial motivations and also opined that approval of the CCGT might be a condition to closing the Vectren South merger transaction.[2] Ms. Medine recommended that Vectren South's Petition be rejected because Vectren South has failed to show that proceeding with building the CCGT at this time is prudent, less risky and a better decision for both customers and the environment.

Mr. Lind responded to Mr. Boerger's testimony about an alleged $200 million "error." He explained that approximately $67 million of the alleged error identified by Mr. Boerger was due to Mr. Boerger's mistaken assumption about whether modeled option costs are stated in 2017 dollars or nominal dollars in the year of incurrence. Petitioner's Exhibit No. 6-R, p. 3. The remainder is due to Mr. Boerger's efforts to compare apples and oranges. As Mr. Lind explained,

[2] While this case was pending, it was announced publicly that Vectren South's holding company was the subject of an acquisition at the holding company level, which is the subject of Cause No. 45109.

the modeling was done prior to the more refined cost estimates for the CCGT that were developed for this case. Rather than based on a design level accuracy of plus/minus 50%, the CCGT design has been refined to a plus/minus 10%. All of the other portfolios were still at plus/minus 50%. As Mr. Lind explained, to compare the other less refined portfolios to the more refined CCGT would require some additional risk factor for the other portfolios. Petitioner's Exhibit No. 6-R, pp. 4-5. But even if one includes the updated cost estimate, Mr. Lind testified that it doesn't change that the lowest cost portfolios still include the fired CCGT. Mr. Lind prepared additional modeling involving coal-to-gas conversion (which we will describe later) and which did include the more refined CCGT cost estimate. While this additional modeling used the more precise CCGT cost and therefore impacted every portfolio that included the CCGT by increasing the overall net present value ("NPV") by $54 million, the portfolios that included the CCGT were still the lowest cost portfolios compared to portfolios that did not include the CCGT. *Id*., pp. 5-6. Regarding the use of the models, witnesses Lind and Vicinus confirmed that the process and modeling for Vectren South's IRP and risk analysis were consistent with the resource planning approach Pace and Burns & McDonnell have used for numerous other utilities.

(iv) Size of the Proposed CCGT. Joint Intervenors' witness Tyler Comings testified regarding the size of the proposed CCGT. Witness Comings testified that Vectren South has not provided a sufficient justification to build a CCGT of the size included in its proposal. Witness Comings also criticized Vectren South's Request for Proposals ("RFP") (which we will describe in greater detail later) which sought resources between 600 and 800 MW, because he believed the Company could have considered combinations of small resources that added up to 600 MW. He further testified that considering smaller options would limit the market risk exposure for ratepayers, as well as permit a combination of bids to make up a least cost alternative. Mr. Comings testified that in order to reduce ratepayers' risk, Vectren South should explore cost effective alternatives that do not require intensive capitalization, but still provide benefits to ratepayers.

OUCC witness Anthony Alvarez also testified regarding the size Vectren South is proposing for the CCGT. Mr. Alvarez testified that Vectren South currently has excess supply, and there is no resource shortfall or inadequacy that supports Vectren's proposed 850 MW CCGT. He also questioned the load forecast used in the IRP and testified Vectren South has excess supply after serving its peak load and therefore has excess capacity to offer into the market and serve new customers.

Industrial Group witness Michael Gorman also testified regarding the size of Vectren South's proposed CCGT. Mr. Gorman testified Vectren South's proposal to build an 850 MW CCGT will result in excess capacity and have a compound impact on Vectren South's cost of service because the plan increases the costs of new generation resources and results in unrecovered stranded costs from the retired resources. Mr. Gorman recommended the Commission implement mitigation measures to reduce the cost burden on customers related to stranded costs and the cost of the new CCGT, as is discussed in more detail in the Commission Discussion and Findings Section. He also recommended the Commission modify the off-system sales margin treatment so that 100% of future wholesale revenues be provided to customers to offset the cost of the proposed resource plan.

Vectren South witness Carl Chapman testified on rebuttal regarding Vectren South's decision to construct an 850 MW CCGT. Mr. Chapman explained the CCGT is essentially two units -- a 700 MW baseload unit to replace 730 MWs of retiring coal unit capacity and 150 MWs of duct fired peaking capacity to replace older peaking units and provide available low cost capacity for growth and wholesale sales opportunity. The additional peaking capacity is provided by the decision to duct-fire the CCGT. The incremental cost of duct-firing the CCGT is $15 million, and that decision must be made at the time the CCGT is constructed (i.e., it cannot be added at a later time.) Mr. Chapman testified that if only the unfired 700 MW baseload CCGT is built, then by 2025, the Company has a projected surplus above MISO's PRM (which fluctuates) of only 51 MW. He further testified that by 2030, the surplus is only 5 MWs and by 2031 the Company will fail to meet its PRM. He testified that by 2036, Vectren South will be short 39 MWs, and all of this assumes Vectren South will not add significant new load. Mr. Chapman testified that with its low capital cost, firing makes sense from a customer perspective. For an incremental cost of 2%, the firing provides a 21% increase in capacity. Nevertheless, if the Commission approves the baseload 700 MW CCGT without firing, Vectren South will proceed to construct the unfired CCGT to replace its baseload coal units. He stated that Vectren South would also consider investing the incremental $15 million to duct fire the unit and be at risk to recoup its investment via retention of the wholesale revenue produced by that peaking capacity.

Mr. Chapman also testified regarding Industrial Group witness Gorman's recommendation that Vectren South pass off-system sales margins on to retail customers. Mr. Chapman testified that Vectren South has decided to commit to provide 100% of wholesale sales revenue from the CCGT (baseload and peaking) to customers. Mr. Chapman explained that once the CCGT is placed in rate base, the benefits from the wholesale revenue produced by the unit will go to reduce customer costs. Mr. Chapman testified that providing 100% of wholesale revenue to customers further improves the NPV of the CCGT, will provide a larger offset to customer costs in general, and adds even more support to the $15 million incremental investment to duct fire the unit.

C. <u>Coal Parties' Modeling</u>. Indiana Coal Council, Inc. witness Philip Hayet – Vice President of J. Kennedy and Associates, Inc. – testified regarding Vectren South's 2016 IRP modeling and the 2017 Update. Mr. Hayet testified that Vectren South's modeling analyses were flawed due to errors, inconsistencies, and a lack of consideration of important factors. Mr. Hayet performed his own analysis and testified that using the same model with certain corrections, including a deferral of a decision to add a CCGT, produced a slightly lower cost result on a NPV basis. He predicated his modeling on the assumption that the Brown 2 scrubber will continue to operate reliably through 2030. He ultimately recommended that Vectren South defer its decision to construct the CCGT.

On rebuttal, Vectren South witness Matthew Lind testified regarding Indiana Coal Council witness Hayet's alternative modeling. Mr. Lind testified that when Mr. Hayet's modeling is corrected for obvious errors, it reaches the same preferred portfolio conclusion as Vectren South's modeling. Mr. Lind provided corrections to Mr. Hayet's modeling in the form of an updated Strategist model and spreadsheets documenting the corrections. Mr. Lind outlined each of the errors he identified in Mr. Hayet's modeling and the impact of the individual errors on his analysis. The first of several errors he identified was that Mr. Hayet had failed to include cost escalation during the seven years of delay that he was urging and that correcting this error alone would change

Mr. Hayet's overall conclusion that delay would be less costly. Mr. Lind also testified regarding the cumulative effect of addressing all of the errors. As part of this analysis, Mr. Lind testified that he included the increased cost of the CCGT to reflect the more recent cost estimates based on a plus or minus 10% confidence level. He testified that when correcting Mr. Hayet's modeling for all of these errors and inconsistencies, the NPV favors the Company's preferred portfolio, even under Mr. Hayet's no carbon regulation scenario. Witness Hayet corrected his testimony after Mr. Lind filed his rebuttal to add the escalation during the period of delay he was urging, and this correction changed his original conclusion that delay was less expensive. ICC Exhibit No. 2, p. 27 (corrected). Mr. Hayet did not address the other modeling issues raised by Mr. Lind.

Mr. Games' rebuttal testimony also addressed witness Hayet's assumption that the Brown 2 unit and scrubber could be operated without added cost and reliability risk through 2030. Apart from the reliability issues created by the frequent cycling of the unit, he explained the structural damage resulting from the corrosive environment created by the unique characteristics of these scrubbers, and based on his direct experience with this equipment, Mr. Games concluded that he could not agree that it would be prudent to continue to operate the Brown 2 scrubber for another 12 years beyond 2018.

D. Renewables and All-Source RFP. Joint Intervenor witness Tyler Comings criticized the costs assumed in Vectren South's modeling for most renewable energy sources. Mr. Comings testified that Vectren's forecast of the capital costs of future wind resources is higher than he would have recommended for the type of planning analysis and its forecast of the fixed O&M costs are lower. Mr. Comings recommended the use of the National Renewable Energy Laboratory's Annual Technology Baseline ("ATB") to develop the forecasts. With respect to future solar resources, Mr. Comings testified Vectren South's forecasts are too high for both the capital and fixed O&M costs. Mr. Comings recommended the reliance on the ATB to develop wind and solar price forecasts. Joint Intervenors' Exhibit No. 2, p. 38. For utility-scale PV, he testified that the ATB midpoint projection would be appropriate. As part of his discussion of renewable costs, he noted that Northern Indiana Public Service Company ("NIPSCO") had recently conducted an RFP and obtained solar and wind bids. Mr. Comings testified that Vectren South's overestimation of renewable costs compared to the ATB data biased the modeling results against renewable resources in favor of non-renewable resources, such as natural gas.

On rebuttal, Mr. Lind responded to Mr. Comings' testimony related to the cost of renewables included in Vectren South's modeling. With respect to wind resources, Mr. Lind noted that prior to revising his testimony, Mr. Comings' originally filed testimony included an inaccurate and inappropriate comparison of assumed capital cost for wind resources between Vectren South and ATB because Mr. Comings failed to account for the declining cost curve over time utilized by Vectren South. Mr. Lind testified that when Mr. Comings updated his testimony to reflect this decline, he recognized that Vectren South's wind costs are only "slightly higher" than what Mr. Comings recommends. Mr. Lind further testified that even with this correction, Mr. Comings' comparison to the ATB figures is incorrect because the ATB figure excludes a 2.1% construction finance factor and is thus understated. Mr. Lind testified that when the 2.1% construction finance factor is included, the ATB capital cost will exceed Vectren South's modeled capital cost for wind over more than half of the planning period. Mr. Lind pointed out that Vectren South assumed a higher capacity factor than the ATB survey and also assumed lower O&M costs compared to the

ATB survey, and as a result, it is likely that the wind prices recommended by Mr. Comings are actually higher than those modeled by Vectren South.

With respect to Mr. Comings' criticisms of Vectren South's solar costs, Mr. Lind testified Mr. Comings again failed to account for the declining cost curve over time in the original version of his testimony. Mr. Lind further testified that while Mr. Comings did update his comparison to reflect the decline, he did not update it to include the 2.1% construction finance factor in the ATB comparison. Moreover, Mr. Lind explained that the national survey costs relied upon by Mr. Comings were presented on a direct current (DC) basis, whereas the 2017 IRP Update stated cost in terms of alternating current (AC), thus requiring that Comings' costs be converted to AC to allow for a valid comparison to be made. When correcting for these additional errors, Mr. Lind testified the solar costs used by Mr. Comings and Vectren South are nearly consistent over the last half of the study period and fairly similar from 2024 onward, which is the point at which capacity is needed.

Mr. Lind also testified regarding the impact of network upgrades and congestion costs on a portfolio that would rely more heavily on renewables. Mr. Lind testified that a portfolio which would rely heavily on renewables to supply power to Vectren South's customers is more likely to source some or all of these resources remote to Vectren South's service territory given the acreage required for such projects, the grid issues that can be encountered, and the enhanced production that can be obtained in certain locations (e.g., northern Indiana). Mr. Lind explained that when significant amounts of power are sourced from off-system resources, congestion costs to Vectren South's customers increase substantially. Because such costs were not part of the 2017 IRP Update assumptions, Mr. Lind concluded that any small differences between the solar costs presented by Mr. Comings and those modeled by Vectren South would be more than offset by the congestion costs associated with greater reliance on such resources. Finally, Mr. Lind noted that even assuming lower renewable costs could be achieved, such resources would likely displace Culley Unit 3's 270 MWs of capacity because that could be done incrementally to reduce the effects of network upgrades and congestion, whereas the CCGT would remain the optimal low cost choice to replace the remaining 730 MWs of retiring coal capacity in 2023. Further, wind and solar are intermittent sources of power; given that Culley Unit 3 would be Vectren South's only baseload capacity under its preferred portfolio, dispatchable baseload generation from a CCGT provides greater flexibility to respond to intermittent resources.

E. **<u>Capacity Price Forecasts</u>**. Mr. Comings testified regarding Vectren South's ability to purchase future needed capacity from the MISO market. Mr. Comings testified that Vectren South overestimated future capacity prices in MISO in its modeling, and in reality, the MISO market has had an oversupply of resources and tempered demand, leading to low capacity prices. He testified the Company's assumption of higher capacity prices is critical, because it makes the economics of building a new resource more attractive. He concluded that Vectren South was placing risk on its customers if the price of capacity is lower. To reach his conclusion, he relied on the MISO auction clearing results for Zone 6 (Indiana) for the past five years. <u>Joint Intervenors' Exhibit No. 2</u>, p. 25. Indiana Coal Council witness Hayet had a similar criticism of Vectren South's modeled capacity prices. He agreed that the cost of new entry ("CONE") served as the upper end of future capacity prices but that, also based on MISO historic auction clearing prices, it was inappropriate for future assumed capacity prices to approximate CONE. Instead, witness Hayet proposed to use 75% of CONE.

On rebuttal, Vectren South witness Joiner responded to Mr. Comings' testimony related to Vectren South's alleged overestimation of MISO capacity prices. Mr. Joiner testified he disagreed with Mr. Comings' contention that Vectren South should assume it will be able to purchase capacity and energy from the MISO market at low prices based upon recent market conditions. Mr. Joiner explained that the MISO market has been volatile in recent years and is experiencing shrinking capacity, and such factors have prompted MISO to evaluate changes to its market structure. Mr. Joiner testified that MISO's recent and pending market reform initiatives, including MISO's Resource Availability and Need ("RAN"), are aimed at increasing capacity and energy prices to incentivize new generation development and are thus leading to higher prices as capacity tightens. As such, Mr. Joiner testified that while MISO's historical capacity and energy prices are indicators of recent trends, contrary to Mr. Comings' MISO auction clearing price testimony, they are not good indicators of expected, long-term future pricing. Moreover, the reported potential for a capacity shortfall by 2024 shows the risk of increased market prices. Notably, we agreed with this conclusion in *Indianapolis Power & Light Co.*, Cause No. 44794 (IURC 4/26/2017), p. 2, 2017 Ind. PUC LEXS 114, *4 ("the MISO auction clearing price is not indicative of the value of capacity for planning purposes and does not invalidate the assumption in IPL's economic analysis.")

F. Refueling Options. OUCC witness Boerger recommended that Vectren model a smaller 440 MW CCGT option in conjunction with gas refueling of one or both Brown units in order to consider a lower capital cost alternative. This option, which replaces retired coal units with a smaller gas baseload unit, was consistent with his stated concern that implementation of large quantities of intermittent renewables could create grid difficulties and that the extension of the life of small coal units is not common in the industry.

Mr. Lind's rebuttal presented the results of additional modeling in response to the OUCC's interest in further analysis related to resource plan options including coal-to-gas conversion that would make use of the Brown unit boilers. Burns & McDonnell performed that modeling and analyzed four additional portfolios, each where the conversion of one or more units to natural gas was considered. Mr. Lind testified that this updated rebuttal modeling used the more refined cost estimates (at the plus/minus 10% confidence level) for the CCGT for comparison with the coal-to-gas conversion portfolios (which were stated at plus/minus 50% accuracy.) Mr. Lind described the results of the updated analysis and testified that when compared with the coal-to-gas conversion portfolios, the preferred portfolio still produces a lower NPV and projected customer cost. Witness Games explained that this is due in part to the high heat rates of refueled units which result in very poor dispatch rates and resulting reliance on the market for energy needs. He explained that such a portfolio would result in customers significantly depending on market purchases for energy. Witness Games testified the fuel cost per MWhr from a converted gas plant is roughly $20 more expensive than the cost from the proposed CCGT when gas price is $4.000/dkt. He showed the much higher heat rates and lower capacity factors at converted plants that were completed between 2013 through the first quarter of 2018. Petitioner's Exhibit No. 4-R. Mr. Games testified during the hearing that the problem of high heat rates means that the refueled units continue to cycle and ramp up and down when dispatched, leading to wear and tear and the risk of additional maintenance costs. Tr., F-2-3.

G. Docket Entry Question & Response. As a follow-up to the additional modeling performed by Vectren South on rebuttal of gas conversion options, we issued a Docket Entry requesting further iterations of gas conversion portfolios. These included refurbishment of Broadway Unit 2 coupled with delays of removal of Warrick Unit 4 and installation of either a simple cycle or combined cycle gas turbine. Vectren South's response included the more refined cost estimate of the CCGT at plus/minus 10%, excluded additional environmental compliance costs at Warrick Unit 4 that would allow for the delay, and were presented with and without the commitment by Vectren South on rebuttal to pass 100% of wholesale revenues to customers if the CCGT is approved. All of the additional modeling requested by our docket entry produced a higher NPV than the lowest cost refueling portfolio presented on rebuttal (to convert Brown and instill a simple cycle gas turbine). As a result, the docket entry response modeling showed these additional iterations of gas conversion options had a higher rate than Vectren South's preferred portfolio. With the sharing of 100% of wholesale revenues, all of the additional modeling produced a higher NPV when compared to the preferred portfolio ranging from 3.5% to 7.0%. Petitioner's Exhibit No. 21. Given that the preferred portfolio was within 4% of the lowest cost 2016 IRP portfolio (CCGT, an additional simple cycle turbine, and delayed renewables), that means the gas conversion portfolios ranged anywhere from 8-12% higher than the lowest cost portfolio. This serves to confirm that the lowest cost portfolios all include as their base the fired 2x1 F-class CCGT with 700 MW of baseload and 150 MW of peaking capacity.

H. Estimated Cost of CCGT and RFP Process.

i. Vectren South. Mr. Games testified that, consistent with the 2016 IRP results, the 2017 Update, and the Pace risk analysis, Vectren South is proposing to build a CCGT with 700 MW of baseload capacity and 150 MW of peaking capacity to replace retiring coal-fired capacity. Mr. Games testified Vectren South is proposing to build a unit with an output of approximately 850 MWs in order to hold some additional capacity to meet its obligations as a public utility, as well as to serve potential new customers and foster economic development. The 850 MW replaces 865 MW of retiring capacity (730 MW of baseload and 135 MW of peaking capacity, including Broadway Unit 2 in 2025). Mr. Games further testified the estimated cost of the CCGT is $781 million (+/-10%). The estimate includes owner's costs and allowance for funds used during construction ("AFUDC"). This figure was based on cost estimates developed by witness Diane M. Fischer, Central Regional Area Director and Associate Vice President with Black & Veatch. Those estimates were derived from a request for proposals for all equipment comprising the CCGT as well as construction. Mr. Games testified Vectren South is proposing to construct the new CCGT on its existing Brown generating site which will provide a conservative cost savings of $50 million resulting from reusing the existing site, facilities and equipment. He explained the critical timing of the in-service date of the CCGT which will be operational for the 2023/2024 MISO capacity year in order to retire the Culley 2 and Brown units and thereby avoid material capital investments otherwise required to operate those units beyond 2023. Similarly, the Warrick Unit 4 joint operating agreement will terminate at the end of 2023. To continue to operate Warrick would also require further investment to comply with environmental regulations.

Mr. Luttrell testified regarding the other replacement generation options Vectren South considered. He described the solicitation of competitive bids for either purchased power or ownership of all or a portion of a new CCGT unit. Mr. Luttrell explained the Company engaged Burns & McDonnell to manage the entire power supply RFP process, and testified this process allowed the Company to compare the best competitive offers for dispatchable baseload capacity to several self-build alternatives, including a partnership alternative. Mr. Luttrell testified that based on this economic and qualitative comparison, Vectren South made the decision to pursue building the duct-fired version of the proposed CCGT at the existing Brown site.

Mr. Lind testified in greater depth regarding Burns & McDonnell's role in developing and managing the RFP process to address Vectren South's power supply needs. He testified Vectren South received 11 unique proposals from six different developers. He further testified each of the conforming proposals was ranked and the top two proposals were compared with Vectren South's self-build proposals. Mr. Lind testified that based on NPV cost and qualitative risk factors, including a congestion analysis related to an off-system generation project developed by a third party, Vectren South determined that the self-build option was the best resource for reliable, long term service.

ii. OUCC. Witness Alvarez testified that, while Vectren South conducted an RFP, Vectren South did not competitively bid the actual CCGT it seeks to build in this case. OUCC witness Aguilar testified that Vectren South has not yet identified a manufacturer, chosen an exact type of CCGT, or issued any bids for the project.

iii. Coal Parties. ICC witness Medine criticized Vectren South's RFP process for a number of reasons, including the contention that Vectren South was involved in the process and the self-build project did not submit a bid as part of the RFP process. ICC witness Hayet stated a similar concern. Ms. Medine also disagreed with the position that self-build projects represent less risk than merchant projects. Ms. Medine further testified regarding the risks associated with self-builds, including cost over-runs. She testified that most if not all new Indiana plants have experienced cost over-runs that utilities look to customers to recover, and unless Vectren South is willing to guarantee costs, this is a risk that should be considered.

iv. Joint Intervenors. Witness Comings testified Vectren South did not facilitate a competitive bidding process, limiting resources and discouraging bidders from offering purchased power agreements ("PPAs"). He further testified the RFP should not have been limited to MISO Zone 6 and should have been similar to another investor-owned utility solicitation.

v. Vectren South Rebuttal. Mr. Luttrell responded to the Intervenors' criticisms of Vectren South's RFP process. With respect to Mr. Comings' criticisms that Vectren South did not facilitate a competitive bidding process, including limiting resources and discouraging bidders from offering PPAs, Mr. Luttrell testified Vectren South is retiring over 70% of its baseload capacity and the RFP was specifically designed to fill that deficiency with reliable cost-effective supply identified by the IRP. Mr. Luttrell further testified PPAs were not discouraged and all four of the responsive bidders offered a PPA. Mr. Luttrell also responded to Ms. Medine's criticisms that Vectren South was involved in many aspects of the solicitation and that Vectren South did not submit a bid as part of the RFP Process. Mr. Luttrell testified Vectren

South used two separate teams—one focused on the RFP and evaluation and one focused on developing the cost estimate for the Vectren South-build CCGT—and each of these teams were separate and walled off from the other. He testified Vectren South's involvement in the RFP process was critical in order to help ensure the RFP would meet the needs its modeling indicated was necessary. He further testified he did not believe the RFP process was negatively impacted as a result of the self-build alternative being developed parallel to the evaluation of the RFP bids, and Ms. Medine acknowledges "there is no evidence that there was inappropriate information transfer." (ICC Exhibit 1, p. 21). Mr. Luttrell explained that ultimately, an evaluation of congestion costs associated with the off-system resource proposal was the driver of selecting the CCGT project at Brown as the best option, and no witness has challenged the substance of this analysis.

Mr. Luttrell also responded to Ms. Medine's position that a PPA does not pose a greater risk than having a regulated utility own the generation facility (ICC Exhibit 1, p. 22). Mr. Luttrell testified that Vectren South believes that an on-system project at an existing utility site subject to regulatory oversight and financed by a public utility, is less risky than relying on a developer. He further testified that when 70% of baseload capacity is at stake, a utility should consider all risks to project completion and to ongoing service in the long term. Mr. Luttrell provided a real-life, recent example of the risks associated with relying on a developer to construct a project. Further, Mr. Luttrell testified that a PPA does represent greater risk compared to a self-build option because the financing, construction, operation, and future financial stability of the seller is not in control of either the regulated public utility or the IURC. Mr. Lind also explained that while the cost estimate for the CCGT is stated at plus/minus 10%, the risk is actually higher (plus/minus 50%) for all portfolios that do not include the CCGT.

I. Construction of Gas Lateral to Serve CCGT.

i. Vectren South. Mr. Perry Pergola – Director, Gas Supply – testified regarding Vectren South's decision to secure the interstate pipeline services of Texas Gas Transmission ("TGT") to provide natural gas service to the proposed CCGT. He testified Vectren South selected TGT because it was the least cost pipeline option to serve the CCGT at the AB Brown location. Mr. Pergola further testified Vectren South (Gas) will build and operate a new gas lateral to interconnect with TGT and serve the CCGT. Mr. Pergola testified that Vectren intends to build and operate the lateral to "eliminate the potential for prospective customers to bypass the gas utility, which would be possible if TGT has built the lateral and had excess capacity available for either existing or future large natural gas customers behind the Vectren South (gas) system." Pergola Direct at 7:10-14.

Mr. Steve Hoover – Director of Engineering – testified regarding the 23 mile gas lateral Vectren South will construct to connect the CCGT with TGT. He testified Vectren South will construct the pipeline itself because, by virtue of its experience building, operating and maintaining new or existing gas facilities in the Vectren South service area, Vectren South (Gas) is uniquely qualified and positioned to construct the new pipeline. Mr. Hoover further testified the estimated cost to construct the gas pipeline is approximately $87 million. This is not included in the estimated cost of the CCGT as presented by witnesses Fischer and Games, as it is expected the costs of the gas pipeline will be reflected in the delivered cost of the gas.

ii. OUCC. OUCC witness Alvarez testified regarding Vectren South's proposal to build the gas lateral to serve the CCGT. He testified Vectren South did not include the costs necessary to build the gas lateral in the $781 million CCGT cost estimate.

iii. Industrial Group. Industrial Group witness Gorman also testified regarding Vectren South's proposal to construct a gas lateral to serve the proposed CCGT. Mr. Gorman testified Vectren South's proposal to self-build the gas lateral is not consistent with protecting the public interest and is anti-competitive. He testified that Vectren South should have considered a third party or TGT to develop the gas lateral. Mr. Gorman testified that to the extent TGT can construct a gas lateral at a lower cost than the Vectren South self-build option, then this option should be adopted. Mr. Gorman further testified that Vectren South's proposal to recover the pipeline costs as part of the fuel costs for the CCGT is not reasonable because the fixed cost to build the gas lateral will not vary with energy generation or volume of gas delivered to the CCGT. Mr. Gorman testified that the gas lateral cost will not move with natural gas prices or LMP market electricity prices. Instead, the gas delivery lateral will be a component of the fixed capital investment that is necessary to develop and operate the CCGT, and that the size or capacity is dependent with the maximum capacity of the CCGT. Gorman Direct at 29. Mr. Gorman testified that rather than allocate the costs of the CCGT 100% on energy, it would be appropriate to allocate the gas lateral cost as part of the CCGT fixed capital cost of the facility and allocate it on a capacity basis.

Deleted: He testified instead

iv. Coal Parties. Indiana Coal Council witness Medine testified regarding Vectren South's proposal to construct the gas lateral. Ms. Medine characterized Vectren South's proposal as a proposal to build the lateral using an affiliate without competitive bidding. She also criticized Vectren South's decision to self-build the gas lateral instead of soliciting bids from third parties. Ms. Medine testified that Vectren South did not solicit bids for the lateral from third parties, and, therefore, it cannot represent that it was the lowest cost option for the construction of the lateral.

v. Vectren South Rebuttal. Vectren South witness Steve Hoover responded to criticisms raised by the Intervenors related to Vectren South's proposal to construct the gas lateral. Mr. Hoover testified that Ms. Medine's characterization of the proposal as an "affiliate transaction" has no bearing on the overall substance of the proposed transaction because there are many reasons why it is advantageous for Vectren South-Gas to construct the gas lateral. He reiterated that the Vectren South-Gas engineering, land services, and construction management teams have already successfully completed two similar projects to deliver gas to Duke Edwardsport and IPL Eagle Valley generating units. He testified it is therefore in the best interest of Vectren South's customers for Vectren South-Electric to enlist the experience and expertise of the gas utility in the pipeline construction and operations. During the hearing, Mr. Hoover acknowledged that there is no requirement that the owner of a gas transmission pipeline be the LDC, and that Vectren is only the LDC for approximately 1-1.5 miles of the 23-mile pipeline. Tr. at H:6. He also acknowledged that TGT is likely qualified to construct the pipeline. Tr. at H:7

Mr. Hoover also responded to criticisms raised by witnesses Gorman and Medine that the lateral project is anti-competitive and being conducted without competitive bidding. Mr. Hoover testified that Vectren South requested TGT to provide a cost estimate to construct the lateral early in the process, and TGT's cost estimate was 10-15% higher than Vectren South's estimate. He further testified that Vectren South will complete a competitive procurement process in order to select a contractor to construct the lateral. Mr. Hoover testified that during the course of bidding and evaluation process, Vectren South will also incorporate cost protections and performance incentives to ensure both competitive and fair pricing.

Mr. Hoover also responded to Mr. Gorman's preference that the lateral be placed in Vectren South's rate base as opposed to the costs being recovered via the FAC. Mr. Hoover testified that like IPL and Duke, Vectren South-Electric has chosen to have a qualified local distribution company ("LDC") own and operate its gas delivery pipeline. Therefore, the pipeline will not be an electric utility asset and the costs associated with it will be recovered through gas rates.

During the hearing, Vectren witness Mr. Swiz testified that Vectren currently proposes that the pipeline would be an asset of the gas utility recovered from Vectren ratepayers via the FAC, and that Vectren proposes that the cost of the pipeline would be recovered 100% on energy. Tr. at H:25-26. Yet Mr. Swiz acknowledged that that the cost to Vectren does not vary by energy used, and that it is a fixed cost. Tr. at H:26. Mr. Swiz further acknowledged that although Vectren is proposing to recover the costs through the FAC, there are multiple ways that assets could be viewed and allocated to be able to contemplate both the fixed and variable nature. Tr. at H:26-27.

As to the allegation that Vectren South's owning the gas pipeline as a gas utility asset is anti-competitive, witness Pergola testified on cross-examination that nearly all of the pipeline (more than 22 of the 23 miles of length) is located in Kentucky and therefore presents no opportunity for bypass, because Vectren South-Gas does not possess the right to serve customers in Kentucky. Tr., G-74.

J. Warrick Unit 4

i. Vectren South. As previously discussed, the IRP modeling showed that retirement and replacement of all coal units with gas provided the least cost plan. Based on operating history, Culley 3 is the best coal unit in the Vectren South fleet. In addition to these factors favoring its retirement, Mr. Wayne Games testified regarding the uncertain future of Warrick Unit 4. Mr. Games explained that Vectren South and Alcoa co-own the unit pursuant to a Joint Operating Agreement ("JOA") whereby each has 50% ownership in the unit. Mr. Games testified that while Warrick Unit 4 will continue to operate in the near term, the long term outlook for the unit is uncertain. He testified the future of the unit is tied to the Alcoa industrial site, and at any time Alcoa could decide to close the smelter unit, which utilizes significant quantities of electricity produced by Warrick Unit 4, based on price volatility in the aluminum market. He testified that the decision to shut down the smelter unit would jeopardize the future of Warrick Unit 4 and this uncertainty makes it difficult to justify investment in the unit or to depend upon it in the long run.

Vectren South witness Carl Chapman also testified regarding the future of Warrick Unit 4. Mr. Chapman testified that Vectren South has agreed to retain its involvement in the unit through

2023 to support the re-opening of the Alcoa smelter. However, he testified beyond 2023 it does not makes sense to continue to invest in a unit that could be subject to shut down if Alcoa decides it has no continuing need for the capacity.

ii. OUCC. OUCC witness Aguilar testified regarding Warrick Unit 4. Ms. Aguilar testified she does not agree with Vectren's assessments of the risk of continuing to operate Warrick Unit 4 under the JOA and she disagrees with Vectren South's "presentation of the agreement." (Public Exhibit No. 1, p. 23). She further testified that Vectren South could continue to operate Warrick Unit 4 beyond 2023 with environmental compliance updates.

iii. Vectren South Rebuttal. Mr. Games responded to OUCC witness Aguilar's contention that Vectren South could continue to operate Warrick Unit 4 beyond 2023. He testified that due to compliance requirements coming in Alcoa's next NPDES permit, it is anticipated that the unit will require significant capital investment to meet environmental standards in the future. He testified that these investments coupled with the uncertainty related to whether Alcoa will continue to operate Warrick 4[3] under the JOA and performance issues at the unit, warn against continued reliance on Warrick Unit 4.

Mr. Chapman also testified regarding the continued operation of Warrick Unit 4. He testified that the partnership with Alcoa jointly to operate Warrick 4 has become highly uncertain in terms of duration and no longer represents a viable long-term resource option. Mr. Chapman further testified that while Vectren South's IRP recommended retirement of Warrick 4 well before 2023, the Company examined each of the coal units to determine whether such units should be retained. He testified that while Culley 3 and Warrick 4 had better profiles in terms of environmental equipment as compared to Vectren South's other units, Culley 3 ultimately had a better operating history based on cost, availability and heat rate. Mr. Chapman reiterated that the significate strike against continued operation of Warrick 4 is the uncertainty surrounding the longevity of the Alcoa partnership. He reiterated the continued operation of Warrick 4 is dependent on the aluminum market, and if Alcoa's industrial operations cease at the site, the environmental requirements facing Warrick 4 will become significantly more stringent. Mr. Chapman ultimately testified the bottom line is assuming Warrick Unit 4 can continue on post-2023 presents great risk.

As noted previously, in response to our Docket Entry question seeking additional modeling of a portfolio with delayed retirement of Warrick 4, Vectren South indicated that an additional capital investment cost of as much as $50 million may be required to retain the unit if IDEM determines not to renew a variance in the unit's current NPDES permit that allows water discharge at a higher temperature. The new draft renewal NPDES permit allows IDEM to terminate this variance at any time, which will likely require the construction of a cooling tower. Coupled with both Alcoa's and Vectren South's ability to terminate the joint operating agreement, this even further increases the risk of reliance on Warrick Unit 4 beyond 2023.

K. Culley Unit 3.

While making investments to preserve some coal-fired generation is not part of the lowest NPV under the 2016 IRP modeling, Vectren South proposes to make investments at Culley Unit

[3] With proper notice, Alcoa can also terminate the JOA.

3, its most efficient plant, in order that it may continue to operate beyond 2023. This decision became part of the preferred portfolio as a result of the risk assessment in the 2016 IRP. Preserving Culley Unit 3 promotes greater diversity in fuel sources and it also lessens the impact on the local coal industry. Witness Retherford described the environmental controls that are needed as a result of CCR and ELG. The Culley 3 Compliance Projects consist of (1) conversion of the current wet bottom ash collection system to a dry handling bottom ash system; (2) installation of a spray dryer evaporator system; and (3) the closure of the Culley West ash pond and construction of a new lined process water and storm water retention pond in its place. This new retention pond will be constructed on the location of the existing ash pond due to space limitations. Witness Fischer developed the cost estimates for the former two and Ms. Retherford provided the cost estimate for the latter. Recovery of the associated costs through a rate adjustment mechanism under Ind. Code ch. 8-1-8.4 was opposed by OUCC witness Aguilar and Industrial Group witness Gorman. We will address their opposition and Vectren South's rebuttal thereto as a part of our findings on the Culley Unit 3 CPCN.

L. Other Ratemaking Issues

The parties also discussed other ratemaking issues related to the CCGT, including treatment of post-in-service capital costs of the CCGT; treatment of stranded coal assets, and contractual provisions between Vectren and its contractors and suppliers of the CCGT for protection of ratepayers. In addition, Petitioner and the Industrial Group also presented testimony on the issue of the appropriate return on equity to be applied to the MATS Projects tracker. The summaries of these issues are included in the Commission Discussion and Findings Section below.

5. Commission Discussion and Findings on CCGT.

A. Pending Summary Judgment Motion and Motion to Dismiss under T.R. 41(B).

Deleted: ¶

[*The Industrial Group does not endorse Vectren's version of Paragraph 5, but submits this redline to address other ratemaking issues in the event that the Commission grants Vectren's request for a CPCN for the CCGT.*]

On July 19, 2018, four months after Vectren South filed its Direct Testimony and three weeks before the OUCC's and all Intervenors' August 10 deadline to submit pre-filed Testimony, the OUCC and several[4] Intervenors filed a Motion for Summary Judgment asking the Commission to vacate the schedule, arguing that we cannot grant Vectren South's request for authority to construct facilities until we have completed a "final" state energy analysis pursuant to Ind. Code § 8-1-8.5-3(c). Alternatively, the Movants asked us to grant them an extension of time to file their pre-filed testimony until at least 45 days after we post a "final" analysis. We took the matter under advisement. At the conclusion of Petitioner's case-in-chief, Alliance Coal made an oral motion to dismiss under T.R. 41(B) on the same grounds. The T.R. 41(B) motion was joined by the OUCC and all of the other Movants except the Industrial Group and Evansville Railway.

[4] The motion was filed by the Coal Parties, Joint Intervenors, Evansville Western Railway, the OUCC, and the Industrial Group.

In construing a statute, we start with its plain language and "attempt[] to give words their plain and ordinary meanings." *Indiana Wholesale Wine & Liquor Co., Inc. v. State ex rel. Indiana Alcoholic Beverage Com'n*, 695 N.E.2d 99, 103 (Ind., 1998) (citations omitted). "[I]n seeking to give effect to the legislature's intent, [the court] read[s] an act's sections as a whole and strive[s] to give effect to all of the provisions so that no part is held meaningless if it can be reconciled with the rest of the statute." *Fort Wayne Patrolmen's Benev. Ass'n, Inc. v. City of Fort Wayne*, 903 N.E.2d 493, 497 (Ind. Ct. App., 2009) (citation omitted).

The Motion is based primarily on Ind. Code § 8-1-8.5, section 3(a), which provides that "[t]he Commission shall develop, publicize, and keep current an analysis of the long range needs for expansion of facilities for generation of electricity," and section 3(c), which provides that "[t]he commission shall consider the analysis in acting upon any petition by any utility for consideration." Ind. Code § 8-1-8.5-3(a) and (c). The Movants interpret these provisions to mean that we cannot consider a CPCN request absent a "*final* Statewide Analysis." We disagree.

Neither provision calls for or implies there must be a "final" or conclusive analysis. Nor does any other provision in Chapter 8-1-8.5. Section 3(a) and other provisions of section 3 direct us to undertake an "analysis" that is subject to ongoing review and revision. An analysis that must remain "current" cannot possibly remain static or culminate in a finished product. We find that the analysis detailed in our draft and final reports of the state of our analysis meets the requirements of the statute.

To the extent the Movants argue that we cannot grant Vectren South's Petition until we completed our annual report on the analysis, their Motion also fails.

Section 3(h) requires us "[e]ach year" to "submit to the governor and to the appropriate committees of the general assembly a report of its analysis regarding the future requirements of electricity for Indiana or this region." Ind. Code § 8-1-8.5-3(h). Section 5(b)(2) provides that a certificate may be granted if the Commission finds the project (A) "will be consistent with the Commission's analysis (or such part of the analysis as may then be developed, if any)"; or (B) the project is "consistent with a utility's specific proposal submitted under Section 3(e)(1) of this chapter and approved under subsection (d)." Ind. Code § 8-1-8.5-5(b)(2)(A) and (B).

This unambiguous language reflects the Legislature's perception that new generation needs may arise at a time while the analysis or even the annual report is incomplete. The Legislature granted the Commission authority to issue a CPCN rather than hold the request in abeyance until the annual report is complete.

It must be presumed that "'the legislature intended the language used in the statute be applied logically and not to bring about an unjust or absurd result.'" *D.B. v. Review Bd. of Indiana Dept. of Workforce Development*, 2 N.E.3d 705, 710 (Ind. Ct. App., 2013) (quoting *Penny v. Review Bd. of Ind. Dep't of Workforce Dev*., 852 N.E.2d 954, 960 (Ind. Ct. App., 2006), trans. denied). Reviewing bodies also avoid "interpreting a statute in such a manner as to render its provisions mere surplusage." *Id*. (citing *In re Adoption of D.C*., 887 N.E.2d 950, 959 (Ind. Ct. App., 2008). The Legislature cannot have meant for the Commission to hold off assessing petitions until its analysis becomes "final" (which will never occur), or even until its annual report is submitted. The State needs power when it needs power. The lights cannot remain off until an arbitrary deadline is reached. Thus, the statute is clear that in considering a CPCN request, pursuant to Section 5(b)(2) we can rely on a complete analysis, a partial analysis, or simply determine whether the proposal is consistent with the utility's own plan and reports.

In sum, the Commission retains authority to review a project at any time. Section 5.5 expressly allows us to "commence a review of any certificate granted under this chapter" when, "in the opinion of the commission, changes in the estimate of the probable future growth of the use of electricity" call for such review. Ind. Code § 8-1-8.5-5.5 ("If the commission finds that completion of the facility under construction is no longer in the public interest, the commission may modify or revoke the certificate.").

Furthermore, we have recognized from time to time that the analysis has until recently not met all of the requirements of section 3.[5] For thirty-five years, we have interpreted the chapter as allowing us to consider a utility specific proposal under section 5(b)(2)(B), and to determine whether the proposal is consistent with the State Utility Forecast Group ("SUFG") forecasts for purpose of determining consistency with the Commission analysis. *See, e.g. PSI Energy*, Cause No. 39175 (IURC 5/13/1992) p. 35, 1992 Ind. PUC LEXIS 126, *83 ("''[T]he SUFG developed, and this Commission adopted on an interim basis, the SUFG's 1990 forecast and plan as this Commission's analysis of the long-range needs of generating facilities in Indiana pursuant to IC 8-1-8.5-3 (the Plan)."); *Indianapolis Power & Light Co*., Cause No. 39236 (IURC 9/2/1992), p. 17, 1992 Ind. PUC LEXIS 297, *40-41 (same); *Southern Ind. Gas & Elec. Co.*, Cause No. 41907 (IURC 9/5/2001), p. 7, 2001 Ind. PUC LEXIS 395, *17 ("As previously discussed, we have found that the Facility is consistent with Petitioner's IRP which is a utility-specific plan. . . . [W]e [also] find that Petitioner's proposal is consistent with the SUFG analysis of the need for electric resources in Indiana."); *PSI Energy*, Cause No. 41924 (IURC 12/17/2002), p. 15, 2002 Ind. PUC LEXIS 544, *98 (same); *Indianapolis Power & Light Co*., Cause No. 44339 (IURC 5/14/2014), p. 28, 2014 Ind. PUC LEXIS 132, *81 ("We find that IPL's proposed 644-685 MW Eagle Valley CCGT and Harding Street 5 & 6 Refueling are consistent with IPL's utility-specific proposal and the SUFG plan."); *Wabash Valley Power Assoc*., Cause No. 44739 (IURC 4/13/2016), pp. 9-10, 2016 Ind. PUC LEXIS 95, *26 (same).

Indiana courts "have consistently recognized that a long adhered to administrative interpretation dating from the legislative enactment with no subsequent change having been made in the statute involved, raises a presumption of legislative acquiescence which is strongly favored by the courts." *Citizens Action Coal. v. Northern Ind. Pub. Serv. Co.*, 485 N.E.2d 610, 615 (Ind. 1985) (quoting *Indiana Dept. of Rev. v. Glendale-Glenbrook Assoc.*, 429 N.E.3d 217 (Ind., 1981); *accord*, *Myers v. Crouse-Hinds Div. of Cooper Inds., Inc*., 53 N.E.3d 1160, 1163 (Ind., 2016) ("Because the General Assembly is a co-equal and independent branch of government, the doctrines of stare decisis and legislative acquiescence are especially compelling in matters of statutory interpretation.") (citing *Fraley v. Minger*, 829 N.E.2d 476, 492 (Ind., 2005); *Layman v.*

[5] *See, e.g., Indianapolis Power & Light Co*., Cause No. 44945 (IURC 2/7/2018), p. 39, 2018 Ind. PUC LEXIS 38, *119("a state energy analysis that meets all of the statutory criteria set forth in Ind. Code § 8-1-8.5-3 does not currently exist."); *accord, Duke Energy Indiana, LLC*, Cause No. 43955 DSM 4 (IURC 12/28/17), p. 41, 2017 Ind. PUC LEXIS 322, *115; *Indiana Michigan Power Co*., Cause No. 44841 (IURC 9/20/2017), p. 28, 2017 Ind. PUC LEXIS 243, *82.

State, 42 N.E.3d 972 (Ind., 2015)); *see also Fishburn v. Indiana Public Retirement Sys.*, 2 N.E.3d 814, 826 (Ind. Ct. App., 2014) (a showing of actual legislative awareness is not required).

Sections 3(a) and (c), on which the Movants primarily rely, have been unchanged since their adoption in 1983. *See* Ind. Acts PL43-1983, Sec. 12. The Commission's longstanding (thirty-five year) practice raises the presumption of legislative acquiescence in this case.

For all of the foregoing reasons, and each of them, the Motions for Summary Judgment and for Dismissal under T.R. 41(B) are denied.

B. Considerations Under Ind. Code § 8-1-8.5-4. We received into evidence Vectren South's 2016 IRP, which identified replacement of over 70% of its existing baseload coal capacity as a lower cost option compared to other alternatives. As a result, Vectren South considered its replacement options with a goal of obtaining replacement capacity resources in time to have such capacity available to meet MISO's 2023/2024 capacity year requirements. The Company considered (A) joint ownership of a baseload unit, (B) purchased power agreements (PPAs) or partial or full ownership of a generation project developed by a third party, (C) a self-build CCGT located on-system, and (D) other options as explained below.

C. Current and Potential Arrangements with other Electric Utilities for:

(A) and (B) The Interchange of Power and Pooling of Facilities.

Under Ind. Code §8-1-8.5-4 ("Section 4"), in acting on a CPCN petition the Commission considers Vectren South's opportunity to enter into arrangements for the interchange of power, pooling of facilities and joint ownership of facilities. As a member of MISO, Vectren South interchanges power on a daily basis, and Vectren South's modeling considered and factored this arrangement. In addition, early in its resource selection process Vectren South identified a potential partner for a joint generation project. Witness Luttrell explained that this partner was interested in owning a minority share of a larger CCGT, and agreed to study locating such a unit on Vectren South's system. As studies ensued, the partnership appeared to be a viable resource option. As a result, the parties studied this joint ownership opportunity throughout 2017, but ultimately in January 2018 the potential partner provided notice that it would not proceed with such a project. Both Vectren South and we have considered the interchange of power and pooling of facilities.

(C) The Purchase of Power.

Pursuant to Section 4, the Commission considers the potential purchase of power by Vectren South when assessing its CPCN petition. On June 20, 2017, Vectren South issued a RFP for dispatchable resources located in MISO Zone 6. Vectren South explained that its RFP specified this location requirement in order to satisfy MISO's requirement that a load serving entity have at least 67% of its resources located within its zone. The RFP sought dispatchable resources based upon the 2016 IRP analysis, which recommended that Vectren South retire nearly all of its baseload coal-fired capacity by the end of 2023. As a result, the RFP was designed to solicit baseload capacity to replace the 730 MWs provided by the retiring coal units. In response, the

Company received nine (9) qualified bids offering both PPAs and offers to build a CCGT and sell that unit or a partial interest in that unit to Vectren South. Using the expertise of Burns & McDonnell ("BMC"), Vectren South evaluated both quantitative and qualitative aspects of the competing bids. Based on BMC's analysis of the levelized cost of energy ("LCOE") of the bids, Vectren South selected the bid with the most favorable LCOE to compare to a self-build option. The selected bid also represented the best response based on an assessment of qualitative factors such as developer credit-worthiness. Witness Lind explained the detailed analysis of this bid, including evaluation of transmission congestion associated with the delivery of power to Vectren South's system. Ultimately, BMC's analysis was that the Company's self-build option had a better net present value than this best bid, and also exposed Vectren South to less risk versus long-term reliance on a merchant developer. Vectren South's rebuttal testimony noted that the merchant developer in question had in fact, even prior to its bid submission, withdrawn its project from the MISO queue without informing Vectren South.

Based on the Company's efforts to work with a partner on a jointly owned facility and its RFP for PPAs and merchant developed generation projects, both Vectren South and we have considered the purchase of power in connection with Vectren South's request.

D. Joint Ownership of Facilities. We have already noted that Vectren South presented evidence that it had considered the joint ownership of a CCGT with a partner. The potential partner ultimately concluded not to move forward with a joint project. Both Vectren South and we have considered the potential benefits from the joint ownership of facilities in connection with Vectren South's request.

E. **<u>Other Methods for Providing Electrical Service</u>.**

i. The Refurbishment of Existing Facilities. Vectren South's 2016 IRP included a Business as Usual Case, which included retrofits with environmental controls of all of Vectren South's existing baseload facilities. In addition, Vectren South considered the cost of replacing the scrubbers at the Brown Units. Finally, Vectren South considered in the 2016 IRP converting Culley Unit 3 to natural gas, and in rebuttal considered retrofitting Brown to natural gas. Out of all of these considerations, the lowest cost option for customers was retirement of all coal-fired generation and construction of the proposed CCGT along with another smaller simple cycle gas turbine. Ultimately, for diversity and other reasons, Vectren South has decided to retrofit Culley Unit 3 with environmental controls and add solar. We find that Vectren South has adequately considered the refurbishment of existing facilities.

ii. Conservation and Load Management. The evidence demonstrates that Vectren South has evaluated the CCGT against other reasonable generation alternatives, and included demand side management and energy efficiency ("DSM/EE") levels consistent with the targets established in Vectren South's latest DSM Order, Cause No. 44927. Vectren South's modeling concludes that even when the cost of energy efficiency has been significantly lowered, the CCGT is still the least cost reliable resource alternative to meet Vectren South's customers' future energy resource needs.

The Joint Intervenors criticize the assumptions used by Vectren South to model the cost of EE, arguing that the assumptions used by Vectren South were too high resulting in a higher cost of EE. Ms. Harris stated in her rebuttal that for purposes of this proceeding, Vectren South opted only to update its growth factors in its revised cost analysis in order to show the impact lower EE costs would have on the energy resources selected in its IRP. Ms. Harris explained that limiting the updates to the growth factors preserved the integrity of Vectren South's 2016 IRP. Petitioner's Exhibit No. 8-R, p. 3. We find that while some of the cost assumptions used by Vectren South could have been updated, on the whole it does not render Vectren South's analysis of EE unreasonable. The Commission finds that Vectren South has reasonably evaluated DSM/EE as a resource, and has shown that DSM/EE will not offset the need for the CCGT requested in this Cause.

iii. Cogeneration and Renewable Energy Sources. Vectren South's IRP modeling process considered the potential for cogeneration facilities to serve its customers and adjusted its load forecast to reflect the potential for cogeneration facilities. Petitioner's Exhibit No. 5, Attachment MAR-1, pp. 99-103. Consequently, the potential for customer-owned generation resources, including renewable generation, to reduce Vectren South's load was evaluated as part of the IRP process that concluded the CCGT was necessary as part of least-cost planning. Therefore, the potential impact of this resource has been evaluated. No party presented evidence in this proceeding to contradict it.

In addition to considering customer-owned renewable energy resources, Vectren South evaluated utility-scale renewable energy as a generation resource in its IRP modeling. The Company provided an update of its IRP modeling as part of this case, which included updated and reduced pricing for renewable resources. Joint Intervenors' witness Comings recommended the

National Renewable Energy Laboratory's Annual Technology Baseline ("ATB") be used for wind and solar pricing. Vectren South did not disagree with using this source as a reliable projection of the cost of renewables; however, Mr. Lind identified adjustments that needed to be made. First, the ATB survey did not include construction finance costs (2.1%) either for wind or solar. Second, the solar ATB survey prices are stated in direct current instead of alternating current. These two adjustments must be made to the ATB survey forecast in order to allow a valid comparison to the updated IRP pricing. When these adjustments are made, it shows that the accepted and verifiable ATB survey prices are very comparable to Vectren South's IRP prices and therefore further support the reasonableness of Vectren South's pricing. Joint Intervenors Exhibit 2, pp. 37-42; Petitioner's Exhibit No. 6-R, pp. 25-33.

Various parties used cross-examination to introduce information pertaining to bids responding to a recent RFP conducted by Northern Indiana Public Service Company ("NIPSCO") as part of its 2018 IRP process. We begin our analysis of this contention by reviewing what we noted in *IPL*, Cause No. 44339 (IURC 5/14/2014), 2014 Ind. PUC LEXIS 132: "[T]he statute does not require a utility to exhaust all statutory alternatives before it may request a CPCN for new capacity. . . . Rather, what is important is that the Commission be given enough information so that the Commission can take into account all of the enumerated alternatives in making its decision." P. 21, *60 (internal quotations omitted.)

Witness Comings briefly mentioned this RFP (10 lines of testimony) as an example of what another Indiana utility has done but he ultimately relied upon the verifiable completed renewable project data in the comprehensive ATB study as the basis for evaluating the renewable resource modeling relied upon by Vectren South. Joint Intervenors' Exhibit No. 2, pp. 44-45. While during the hearing, several Vectren South witnesses were questioned about the NIPSCO RFP, none of the witnesses had any personal knowledge of the NIPSCO RFP. We are also aware that each utility plans for the types of resources suitable to meet its specific needs. Here, with the planned retirement of 730 MWs of baseload capacity, Vectren has sought dispatchable replacement capacity. Based on its replacement capacity need, there would need to be 1,480 MWs of solar or over 7,000 MWs of wind to replace this retiring capacity at current MISO capacity accreditation levels, and obviously, the vast majority of such resources would likely not be located on Vectren South's system in southwestern Indiana. Even if theoretically available without significant congestion issues, these renewable resources are intermittent in nature and would require market purchases when not fully available. The context in which Vectren South conducted its IRP and RFP must not be ignored when assessing resource selection and pricing. Regardless, we admitted into evidence over a hearsay objection the NIPSCO PowerPoint presentation, which is dated in advance of the prefiling date for the OUCC and Intervenors in this Cause (July 24, 2018). Joint Intervenors' Exhibits CX-13 and CX-14. This exhibit purports to set out the results of NIPSCO's RFP. *Id*., p. 19. To the extent this document purports to summarize the bids that NIPSCO received, it is unquestionably hearsay.

While the rules of evidence are somewhat more relaxed with administrative agencies, the Indiana Supreme Court has confirmed that we must abide by the hearsay rule. In the administrative context:

> The Residuum Rule is a logical development of the Hearsay Rule.

* * * *

> Indiana courts have unerringly applied a modified version of the Residuum Rule. It is improper (albeit not reversible error) for the Industrial Board to admit incompetent hearsay and an award must be supported by some competent evidence presented at the hearing ***
>
> * * * *
>
> As the law now exists in Indiana, administrative agencies such as the Industrial Board exercise a quasi-judicial function and, although not as strictly as courts of law, are subject to the operation of the Hearsay Rule. . . .
>
> * * * *
>
> The Board can admit all hearsay evidence without fear of automatic reversal. If properly objected to at the hearing and preserved on review and not falling within a recognized exception to the Hearsay Rule, then an award may not be based solely upon such hearsay.

CTS Corp. v. Schoulton, 270 Ind. 34, 39-40, 383 N.E.2d 293, 296 (1978). Since Vectren South properly objected to the NIPSCO presentation on hearsay grounds, and there is no independent corroborating evidence of the bids that NIPSCO received, we may not consider this information for purposes of our decision. We find reliance on these price quotes to compare to Vectren South's modeling inputs is problematic for a number of reasons. First, as noted in the NIPSCO presentation, the pricing was preliminary in nature, subject to due diligence, related to projects with various degrees of uncertainty as to future development, and ultimately subject to negotiation to reach definitive terms. Thus, this information is very different from the ATB survey prices based on actual projects and relied upon by Joint Intervenors' witness Comings to compare to Vectren South's updated IRP price assumptions. Moreover, while witness Lind was able to discern the basis for the ATB price data and adjust it to provide a valid means of comparison to the IRP, there is absolutely no way to take the summary of preliminary quotes in response to the NIPSCO RFP mentioned in the PowerPoint and construct a meaningful comparison. Second, location of generation resources is critical to determining the actual cost of the resource. As previously mentioned, the Vectren South IRP did not attribute congestion costs to solar and wind resources, and thus likely understated the cost to use such resources to meet capacity and energy requirements. Here, the bids submitted to NIPSCO are associated with projects to be developed in unknown locations. It is public knowledge that wind resources in Indiana are best located in the northern part of the state (e.g., in NIPSCO's service territory). Reliance on a specific preliminary bid to use for IRP modeling assumptions compared to the BMC assumptions based on verifiable industry data or the ATB study based on actual project data would require more information regarding the bid terms such as price escalation, interconnection cost, and congestion analysis to assess the true cost of such a project. All of these reasons serve as the baseline for why it is incompetent evidence upon which we cannot rely for purpose of evaluating the culmination of Vectren South's resource planning. Here, Vectren South conducted a transparent process, reviewed by the Commission Staff and relying on established models and experts to assess many scenarios – that process cannot be abandoned because of an unrelated RFP by another utility indicating the possibility of certain projects being developed somewhere else in the state. Regardless, the ATB study and Vectren South's own modeling provide ample and reliable evidence of solar and wind prices. While this still is not a precise analysis given the importance of location and corresponding consideration of congestion cost, as well documented by Vectren South's own RFP analysis of an off-system CCGT project and its history of incurring significant congestion costs associated with wind PPAs tied to wind farms located in the northern part of the state[6], it certainly provides the type of information that has historically been relied upon to make reasonable resource planning decisions. The hearsay evidence purporting to summarize initial price quotes obtained by another utility, without the ability to evaluate any details associated with those actual quotes much less any evidence of the ultimate cost of obtaining delivery of such resources, does not undercut the IRP process set forth in this case and cannot be used as a meaningful comparison to Vectren South's modeling assumptions. This is especially true where the environmental parties presented the independent ATB study, which confirms the pricing for renewables included in the 2016 IRP and 2017 Update modeling. As a result, we are able to check the reasonableness of the IRP renewable assumptions by referencing the ATB study and the discussion of the comparative pricing in Mr. Lind's rebuttal testimony.

As a result, we have enough information concerning all of the enumerated statutory alternatives for us to make a decision. We find that Vectren South has considered and we have taken into account other methods of providing reliable, efficient, and economical electric service including refurbishment of existing facilities, conservation, load management, cogeneration and renewable energy sources.

F. <u>Findings under Ind. Code § 8-1-8.5-5</u>.[7]

i. *Best estimate of Construction, Purchase or Lease Costs Based on the Evidence of Record of Proposed CCGT*

The cost estimates for Vectren South's proposed CCGT were developed and presented by witness Diane Fischer. Black & Veatch developed a design basis and conceptual design and thereafter developed a cost estimate. Several conceptual designs were first developed. From that, ten plant alternatives for purposes of estimating costs were identified. This was later narrowed to seven alternatives for which detailed costs were developed. Competitive bids were obtained for

[6] Mr. Games testified on rebuttal that the average 5-year congestion component of the locational marginal price ("LMP") paid by Vectren South for wind generation from Benton County Wind Farm and Fowler Ridge II Wind Farm is much higher than the congestion component at the Brown and Culley stations. Indeed, Vectren South has experienced negative LMPs for the two wind farms in the northern parts of the State. Mr. Games explained there is a much higher congestion charge and many more negative LMP hours for generation that is farther from the load it is designed to serve. <u>Petitioner's Exhibit No. 4-R</u>, p. 19.

[7] In addition to the findings we enumerate under Ind. Code §8-1-8.5-5, there is also a requirement related solely to proposals to construct coal-fired generation. Section 5(b)(4). Given that Vectren South is proposing a CCGT, this particular finding is not applicable.

the equipment and materials. Based upon Black & Veatch's experience as an engineering, procurement and construction ("EPC") contractor, Black & Veatch was able to estimate indirect costs, contingency, overhead, and profit for the EPC contractor. Bids were also received for construction. Ultimately, Ms. Fischer testified that the cost estimate for the proposed CCGT had been refined to +/- 10%. The total estimated project cost (excluding owner's costs) was $582,000,000. The owner's costs were then provided by witness Games, including insurance, contingency, study, and AFUDC. The total cost estimate was $781,000,000.

No party presented any contrary evidence of the estimated cost for the proposed CCGT. We find that $781 million is the best estimate of the costs of the proposed CCGT based upon the evidence of record. This cost does not include the estimated $87 million for the gas lateral pipeline, which we find to be gas utility plant as proposed by Vectren South.

ii. *Consistency of Proposed CCGT with Vectren South's Utility-Specific IRP and State's Expansion Plan*.

(1) Statewide analysis consistency. Indiana Code § 8-1-8.5-3 provides that "the Commission shall develop, publicize, and keep current an analysis of the long range needs for expansion facilities for generation of electricity." Ind. Code § 8-1-8.5-3(a). This Commission issued its analysis in draft form on June 20, 2018. Petitioner's Administrative Notice 2. We have already addressed Intervenors' arguments in procedural motions that Vectren South's request to construct new generation under Chapter 8.5 cannot be granted because this Commission has not completed a "final" statewide analysis described in Indiana Code § 8-1-8.5-3(a).

We received into evidence our Draft Report. The day following the close of the evidentiary hearing, we made edits to the Draft Report, removed the label "Draft," and issued our Report of our Statewide Analysis to the General Assembly.[8] Our "analysis" required by the statute is ongoing; the "report" is a snapshot of the state of the analysis at a particular moment in time. With respect to Vectren South's request, the state of our analysis had not changed materially from the date of the Draft Report issued in June to the actual Report issued in October. OUCC witness Aguilar agreed that Vectren's proposal was consistent with the Draft. Public's Exhibit 1, p. 9. We find Vectren South's proposal is consistent with the Statewide Analysis.

(2) Vectren South IRP consistency. Vectren South has submitted a utility specific proposal under Ind. Code § 8-1-8.5-3(e)(1). Consistent with direction from the Commission, Vectren South engaged in an IRP planning process to evaluate how different portfolios performed under a range of future potential market conditions and uses and to determine the optimal mix of supply or demand resources to provide electricity to Vectren South's customers. The record reflects that as part of its 2016 IRP process Vectren South engaged in its most detailed planning analysis and worked with several industry experts to conduct technical modeling, develop scenarios and conduct risk assessments. (Public's Exhibit 5, p. 3). The record further reflects that within this process, Vectren South considered 36 different generation resources for modeling, including natural gas, coal, wind, solar generation options, and battery storage and, from this analysis, fifteen portfolios comprising a mix of supply and demand side resources were developed

[8] Pursuant to 170 IAC 1-1.1-21(h), this Commission may, on its own motion, take administrative notice of matters within our official files and we hereby elect to do so with respect to the 2018 Report on the Statewide Analysis of Future Resource Requirements for Electricity.

and modeled. *Id*. at pp. 4-5. Vectren South also engaged and considered stakeholder input throughout the process. *Id*. at pp. 7-10.

Vectren South's IRP process identified the mix of resources producing the lowest cost NPV in the base case: retire all coal fired units, and replace those resources with gas-fired generation. Specifically, the model selected an F-class duct-fired .05 CCGT, along with an F-class Simple Cycle Gas Turbine in 2024 as the lowest cost option. After assessing risk, Vectren South's 2016 IRP ultimately selected as the preferred portfolio the same CCGT but refurbishment of Culley Unit 3 plus 50 MW of solar instead of an additional simple cycle gas turbine.

Vectren South updated its 2016 IRP base case scenario to address concerns raised by stakeholders and the final Directors' Report. *Id*. at 13. These changes included updates to several market prices included in the base case, as well as updates to solar and EE pricing assumptions which ultimately improved the competitiveness of these options within the optimization modeling. *Id*. at 14. The record reflects that despite these updates, the results of the IRP optimization modeling did not materially change, and the F-class Fired .05 CCGT was still part of the optimal portfolio. *Id*. at 15. Pursuant to the results of the 2016 IRP and subsequent update, Vectren South determined to construct the proposed CCGT to replace the retiring coal-fired baseload capacity. Petitioner's Exhibit No. 4, p. 13.

Several Intervenors raised criticisms regarding Vectren South's 2016 IRP process and modeling. The majority of these criticisms related to Vectren South's decision to only update portions of the IRP and/or its decision to move forward with its decision to retire its coal-fired capacity now, as opposed to waiting until its 2019 IRP process is complete or environmental regulations impacting its coal-fired units are more settled. On rebuttal, a number of Vectren South witnesses explained why Vectren South cannot wait any longer to make the decision to retire its coal-fired units and construct the proposed CCGT. Specifically, Mr. Games sponsored a timeline for the CCGT construction (*see* Petitioner's Exhibit No. 4-R, Attachment WDG-3R) which showed the current project schedule for the proposed CCGT. Mr. Games testified that delaying the decision would push the construction schedule out 2-3 years and would leave Vectren South's customers vulnerable to market capacity and energy prices to reliably serve its customer base during this period. Petitioner's Exhibit No. 4-R, pp. 26-27.

In terms of the environmental compliance deadline facing Vectren South, Ms. Retherford's rebuttal testimony put to rest any further debate regarding the application of the CCR regulations to the Brown and Culley units. As she explained, the results of recent groundwater testing at these sites confirm that the ash ponds must cease operations and that Vectren South must either address unit discharge to achieve compliance or cease operations by the end of 2023. Moreover, even in the event that groundwater monitoring results did not lead to the requirement to close the ash ponds, Vectren's ash ponds similarly failed the location restriction which prohibits placement of ash within 5 feet of the uppermost aquifer. The compliance costs used in the IRP model to continue operation of these units beyond this date cannot be avoided.

Delay is not an option. It places Vectren South's customers at extreme risk of reliance on the market. The risk to those customers in terms of the magnitude of the reliance and the uncertainty of capacity in MISO Region 6 is greater than that faced by IPL in Cause No. 44339, where we found: "reliance on capacity purchases for a large portion of its resource requirements (approximate 10%) is unreasonable given the uncertainty surrounding the projected reserve margin for the MISO region in 2017." *IPL*, p. 28, 2014 Ind. PUC LEXIS 132, *80. Here, it is close to 75% of Vectren South's resource requirements and a larger projected capacity deficit in Zone 6.

The OUCC requested Vectren South perform additional modeling to consider gas refueling at one or more of the A.B. Brown units. Vectren South worked with Burns & McDonnell to perform such analysis, and Burns & McDonnell analyzed 4 additional gas conversion portfolios where refueling was considered. Petitioner's Exhibit No. 6-R, pp. 7-8. The results of this updated analysis were consistent with Vectren South's 2016 IRP analysis, and Vectren South's preferred portfolio again produced a lower NPV and customer costs when compared to the gas conversion portfolios. *Id*. at 9.

Ultimately, Vectren South's IRP and its additional analysis has shown that the duct-fired 850 MW CCGT on the A.B. Brown site is the reasonable, least cost resource to meet Vectren South's customers' needs for electricity. Apart from cost, this efficient resource that is capable of cycling in response to the MISO market reliably replaces the retiring coal and gas peaker units with more efficient and dispatchable baseload capacity. Based on the record evidence, we therefore find the resource planning and selection process used by Vectren South for selecting the preferred portfolio and the 850 MW duct-fired F-class 2x1 CCGT is consistent with its 2016 IRP and updates, and is therefore consistent with Vectren South's utility specific proposal under Ind. Code § 8-1-8.5-3(e)(1), which we approve under Ind. Code § 8-1-8.5-5(d).

iii. *Public Convenience and Necessity*.

The public convenience and necessity criterion is common in public utility matters and generally concerns whether the proposal is fitted or suited to the public need. *Indiana Michigan Power Co.*, Cause No. 44871 (IURC 3/26/2018), 2018 Ind. PUC LEXIS 75. Vectren South contends the CCGT is suited to the public need because (1) continued reliance on its existing generation resources represents a more expensive method of meeting future customer demands, (2) Vectren South's resource planning has identified a CCGT as the least-cost alternative to continue meeting those future customer demands, and (3) the CCGT replaces the coal baseload units with a dispatchable, non-intermittent resource suited to operating effectively in response to MISO price signals.

The retirement of the Brown Units 1 and 2, Culley Unit 2 and Warrick Unit 4 units, as well as several older peaking units, is suited to the public need. The Company's IRP modeling establishes the lowest-cost option for customers is to retire the existing coal-fired units and construct a CCGT that replaces this capacity. This modeling concluded that the lowest-cost portfolio would retire all coal-fired generation in Vectren South's portfolio and construct gas generation to replace the capacity. Petitioner's Exhibit 5, Attachment MAR-1, p. 226. However, our proposed IRP Rules require a risk analysis to be conducted as part of the IRP modeling to evaluate how portfolios perform against a variety of future scenarios. The Company's risk evaluation demonstrated that balanced gas generation with coal and renewable generation hedged risk in a cost effective manner. *Id*. at 228-229. Vectren South proposed to retain one of its coal fired units, Culley Unit 3 (to be discussed in connection with the request for a CPCN pursuant to Ind. Code ch. 8-1-8.4 below), and replace the other units with the proposed CCGT. This scenario performed well in the risk analysis, indicating that the incremental cost of retaining Culley Unit 3 provides an effective hedge against future risk.

ICC witnesses Hayet modeled a scenario that proposed delaying construction of a CCGT and continuing operation of Brown Unit 2 until 2030. The engineering review of the Brown scrubbers found many steel elements and foundations are in "precarious shape" and that the scrubber absorbers are "at some risk of at least partial vessel collapse. . . ." Petitioner's Exhibit 4, Attachment WDG-1, pp. 1-2. Based on this assessment of the condition of this equipment, a recommendation was made to retire the scrubbers over the next five to ten years, by then up to fifteen years longer than typical design life. In fact, Burns & McDonnell concluded that given current condition and ongoing deterioration, the scrubbers should be retired "before their total life reaches 40 to maximum 45 years" and the Unit 2 scrubber will hit 40 years in 2026. *Id.* at pp. 3-3. Thus, the report supports retirement before hitting this age, not running until the maximum age. Reliance on the scrubber for this maximum period of 40 years or more presents risk of a significant failure and the resulting dilemma of whether to invest in the scrubber to get it to operate through this period. Despite this risk, Mr. Hayet's modeling is based upon the assumption that the Brown Unit 2 scrubber can continue to function until 2030. Mr. Hayet characterized his scenario as "comparable to" Vectren South's modeling from a cost perspective, but necessary corrections identified by Vectren South witness Lind showed this option was actually more expensive. Petitioner's Exhibit No. 6-R, pp. 13-20. Witness Hayet originally had not included in his model the cost escalation during the period for which he was recommending delay. Mr. Hayet accepted the correction and changed his testimony to say his results were "comparable" to Vectren South's modeling. But that was without considering the other corrections identified by witness Lind that we find should be made. Further, Mr. Hayet assumes these dual-alkali scrubbers will operate that long without added cost. Mr. Games testified that the scrubbers are already beyond their design life, and that their corrosive environment causes regular damage to the Brown infrastructure, resulting in safety concerns. The scrubbers will be 44 and 37 years old in 2023, and we agree with Vectren South that pushing them an additional seven years is not a prudent approach. Most importantly, Mr. Hayet did not factor in the costs required to bring Brown Unit 2 into compliance with ELG requirements, which would further disadvantage his CCGT delay scenario. This would include bottom ash conversion and dry fly ash modifications, as well as a new lined landfill with leachate collection. In addition, a new scrubber would require wastewater treatment or zero liquid discharge ("ZLD"), which are also unaddressed in Mr. Hayet's modeling. Therefore, for both reliability and cost reasons, Mr. Hayet's scenario does not represent a credible alternative.

Furthermore, while we have indicated in previous CPCN cases that "least-cost planning is an essential component of our Certificate of Need law", we have also recognized that least-cost planning does not require selection of the absolute lowest cost alternative. *Southern Indiana Gas & Elec. Co.*, Cause No. 38738, (IURC 10/25/1989), p. 5, 1989 Ind. PUC LEXIS 378, *7, *quoted in IPL*, p. 20, 2014 Ind. PUC LEXIS 132, *58. We have defined "least-cost planning" as a "planning approach which will find the set of options most likely to provide utility services at the lowest cost once appropriate service and reliability levels are determined." *Id.* at *10. We also consider risk created by future uncertainty. For this reason, we have emphasized that the CPCN statute does not require the utility to select automatically the least cost alternative. And here, Vectren South has not: if Vectren South were solely focused on "least cost," the modeling would have said build the duct-fired CCGT, retire Culley 3, add another smaller simple cycle gas turbine, forgo any remaining coal and delay renewable resources prior to 2034. Petitioner's Exhibit No. 5, Attachment MAR-1, p. 204. Nor does the statute require the utility to ignore its obligation to provide reliable service or to disregard its exercise of reasonable judgement as to how best to meet its obligation to serve. "If an Indiana utility reasonably considers and evaluates the statutorily required options for providing reliable, efficient, and economic service, then the utility should, in recognition that it bears the service obligations of IC 8-1-2-4, be given some discretion to exercise its reasonable judgement in selecting the option or options to implement which minimize the cost of providing such services." *PSI Energy, Inc.*, Cause No. 39175, p. 14 (IURC 5/13/1992), 1992 Ind. PUC LEXIS 126, *33-34, *quoted in IPL*, p. 20, *58-59. Vectren South has exercised its reasonable judgement in selecting an option that balances minimizing the cost of providing services against the risks of future uncertainty.

The Coal Parties challenge Vectren South's decision to retire its existing facilities. As noted above, the modeling performed by Vectren South supports the decision to retire these units as an exercise of Vectren South's reasonable judgment. They raised issues such as risk of higher gas prices due to competition from LNG, environmental challenges to construction of new pipelines, and lack of storage. Vectren South's modeling relied upon multiple industry-accepted forecasts for natural gas prices, and Vectren South explained how its particular location is uniquely suited to obtain supply with pipelines flowing in both directions and ample storage. Further, the primary challenges faced by Brown Units 1 and 2, Culley Unit 2, and Warrick Unit 4 are their relative inefficiency in the MISO market and the need to invest significant capital to keep the units operating. On a combined basis, Vectren South would need to invest millions of dollars simply to keep these units operating beyond 2023. While such investments would enable Vectren South to continue to rely on these units to satisfy MISO capacity requirements, the relative inefficiency of these units in the markets exposes customers to significant purchased power costs and higher operating costs when the units are operating. Notably, the National Coal Council recently provided a report to the Department of Energy regarding the state of the country's coal fleet which fully explains the problems associated with frequent unit cycling and warned that the reliability of coal plants "could be significantly less" and that the wear and tear caused by cycling in response to market signals results in "increased capital expenditures, increased O&M costs, increased outages, and higher fuel consumption." Petitioner's Exhibit No. 4-R, p. 10. This explains why even post-EPA announcement of the replacement of the CPP, major utilities such as Duke and AEP, and even Kentucky utilities, are continuing to retire aging coal units.

As we consider Vectren South's evidence regarding the specific issues driving the need to retire its coal units, in terms of context it is helpful to review what is transpiring in the electric industry and in Indiana regarding the shift in generating resources. Since 2012, 458 coal units constituting over 52 gigawatts of capacity have been retired nationwide, with 97 of those units located in the MISO footprint. Petitioner's Exhibit No. 4-R, p. 11. At this time, Vectren South's units are among the smallest remaining in operation in Indiana. *Id.,* p. 6. Many retirements have occurred in Indiana, with more being announced. The Brown units and Culley 2 also have the highest heat rates in Indiana once Schafer Units 14 and 15 are retired. *Id.,* p. 7.

Reliance on Brown Units 1 and 2 beyond 2023 would require significant capital investment. New emission control scrubbers would be required and the evidence establishes such scrubbers would cost approximately $300 million. While OUCC witness Aguilar referenced publicly available scrubber installation costs for other generating facilities she claimed might have a lower cost, the information she provided was incomplete. Vectren South witness Farber identified all other costs related to these installations, demonstrating that Ms. Aguilar's alternatives had similar costs. Public's Exhibit No. 1, pp. 20-21; Vectren South's Exhibit No. 15-R, pp. 24-26. And as to the prospects of the technology suggested by Witness Dombrowski, this technology is unproven in North America for a baseload plant like those owned by Vectren South. The Coal Parties' testimony never provides any definitive information on how use of such technology would require less investment compared to a widely used scrubber technology. This fact alone would cause us to be skeptical of her recommendation; when we pair this with the cybersecurity risk from having technology developed by a Chinese corporation installed on critical infrastructure to the United States electricity grid, and the significant increase in chemical security handling measures necessitated by the increased use of ammonia, we agree that this is not a prudent solution to Vectren South's baseload capacity needs.

Ms. Retherford testified that continued operation of Brown Unit 2 beyond 2023 would require further investments, including a new ash pond and conversion of its fly ash handing system to a fully dry system. Petitioner's Exhibit No. 9-R, pp. 5-10. In addition to these investments, Mr. Games described the risks of continued reliance on Brown Units 1 and 2 including incremental capital investments to replace worn equipment, safety and reliability risks of continued reliance on the scrubbers. Mr. Games noted that changing market conditions have resulted in a cycling of these units in a manner they were not designed for which creates a risk of further damage that must be repaired. Petitioner's Exhibit No. 4-R, pp. 12-16. Indeed, as recently as the summer of 2016, there was a 3-month outage at Brown Unit 1 caused by this cycling that resulted in $3.8 million worth of repairs. *Id.,* p. 9.

Substantial evidence also supports the retirement of Culley Unit 2. Culley Unit 2 is Vectren South's oldest, smallest and least efficient coal unit. Continuing to operate Culley Unit 2 through 2036 would require an estimated $70 million in incremental capital investment. While OUCC witness Aguilar believed Culley Unit 2 could continue to operate by sharing environmental compliance with Culley Unit 3, Ms. Retherford established the unit would require its own investments to comply with ELG. Public's Exhibit No. 1, p. 22; Petitioner's Exhibit No. 9-R, p. 19.

Vectren South has also presented evidence leading us to find it is prudent to retire Warrick Unit 4. This unit is 54 years old, will require significant capital investment to enable compliance with NPDES permitting and Clean Water Act Sections 316(a) and (b) regulations, and is subject to a joint operating agreement that limits Vectren South's ability to control the future of this unit. Due to corporate restructuring and operational changes, the joint operation of the unit was in peril as Vectren South prepared its 2016 IRP; ultimately, the parties were able to agree to extend the joint operations through 2023, but the agreement can be terminated by either party. Vectren South also explained that essentially the duration of the joint operation of the unit would always be subject to the volatility of the world aluminum market. From an environmental standpoint, a recent permit renewal issued by IDEM has increased the likelihood that a cooling tower would be needed to continue operations beyond 2023, with such incremental costs not having been reflected in the IRP modeling. Petitioner's Exhibit No. 21. As we have noted, the IRP modeling demonstrates that retiring coal units and replacing them with natural gas is the lowest cost option. The Company, however, found that retaining one coal-fired unit offered a cost-effective hedge against future risk. In evaluating its coal units, Warrick Unit 4 was rejected in favor of Culley Unit 3 due to the uncertainty discussed above and also because Warrick Unit 4 has experienced higher forced outages and faces minimum load restrictions. We will address the environmental controls associated with Culley Unit 3 later in this Order.

The CCGT also provides Vectren South the ability to retire and replace older inefficient peaking units. The largest of these is the Broadway Unit 2, which will be 14 years beyond its expected useful life when it is scheduled to be retired in 2025. The unit's efficiency is less than half of the proposed CCGT and a major rebuild of the unit would be required were it to be kept beyond 2025.

Several parties suggested that Vectren South was not diversifying – that it was instead moving from a portfolio of nearly all coal to a portfolio of nearly all gas. This is not true. Vectren South's existing baseload portfolio consists of 100% coal-fired generation; the preferred portfolio will have a mix of 69% gas (700 MW), 26% coal (270 MW), and 5% renewable (50 MW). *See* Petitioner's Exhibit No. 5, Attachment MAR-1, pp. 34, 47.

In summary, Vectren South has reasonably determined the time has come to retire 730 MW of baseload capacity and use the time until 2023 to bring replacement capacity online. Vectren South proposes to replace the retired 730 MW of baseload capacity with an efficient 2x1 F-class CCGT providing 700 MW of baseload capcaity. This grew out of its 2016 Integrated Resource Plan. Thirty-six different technologies (representing an assortment of renewables, storage, natural gas, and coal) were modeled and screened on equal footing using a busbar, or levelized cost of electricity, comparison and then a portfolio optimization. Petitioner's Exhibit No. 5, Attachment MAR-1, pp. 79 and 166. Fifteen different portfolios emerged from this iterative process as potential solutions. *Id.,* p. 81. Some portfolios included a CCGT; some did not. Some continued reliance on coal; some abandoned coal. Varying degrees of renewables and storage were included. Out of this modeling, the optimal portfolio in terms of cost was a switch to nearly all gas, with the duct-fired F-class CCGT serving as the foundation of the "heavy gas" portfolio." *Id.,* p. 82. Importantly, under every scenario (base and large load, high and low regulatory, high and low economics, high technology), the modeling always selected the 2x1 F-class CCGT (whether fired or not) as providing the lowest net present value ("NPV"). *Id.,* pp. 204-10. The 2016 IRP also went beyond a simple comparison of the respective NPVs; from a reliability standpoint, replacing the coal units' 730 MWs with a 700 MW baseload gas unit is the sensible choice. The CCGT can ramp up and down in response to the market and has a far better heat rate, and is located on system to avoid congestion costs. Despite the multiple criticisms leveled at Vectren South's modeling – from capacity prices to renewable prices, to gas prices, to demand response – we agree with what was stated in our Director's Report: "Vectren prepared credible and well-reasoned scenarios." Joint Intervenors' Exhibit No. 2, Attachment TFC-6, p. 41. Further, Vectren South (as all utilities) has "made significant improvements in all respects of [its] IRP . . . using state-of-the-art methods [and] . . . unprecedented transparency and candor." *Id*., p. 6. No other party offered credible modeling results to contradict the conclusions from the 2016 IRP or the 2017 Update.

We find that all models reviewed during the IRP process and all models presented in this case support one simple fact: from the perspective of minimizing customer cost, the 700 MW baseload CCGT must be the foundation of the portfolio that is chosen. Said another way, any alternative portfolio that does not include the proposed CCGT is more expensive, including models that considered smaller CCGT units. As supported by the modeling of various resource plans, smaller CCGTs may be less expensive to build but lack efficiencies of scale and thus are more expensive on a per MW basis. Thus, other plans with smaller CCGTs must supplement the gas unit with other types of resources and cost more on an NPV basis. Ultimately, no party presented a model in this case contesting this conclusion.

Joint Intervenors' witness Comings proposes that we require Vectren South to conduct additional analysis before granting the proposed CPCN and others pointed to the all-source RFP conducted by NIPSCO as an example of further analysis Vectren South should perform. Joint Intervenors' Exhibit 2, p. 47. As previously discussed, Mr. Comings presented the ATB study as evidence of solar and wind prices. When parties favoring use of renewables present evidence of the costs of such resources and that evidence supports the utility IRP assumptions (without even considering congestion costs that typically are associated with getting energy from such projects to the utility system), there is no need to speculate on pricing based on hearsay evidence summarizing price quotes. In the end, if Vectren South retires its coal units apart from Culley 3, it will go from 1,000 MWs of baseload capacity to 270 MWs. Vectren South has presented its view as a utility that in this circumstance, having replacement dispatchable base load capacity is important from an operational flexibility, reliability and cost standpoint. We agree that such a position is reasonable. Vectren South's on-system resource proposal also avoids incurrence of congestion costs which is a benefit to the long-term provision of reasonably priced service to customers. As a result, while we must determine whether the specific baseload resources proposed in this proceeding are in the public interest, we generally find that when a utility with 100% coal-fired baseload capacity replaces nearly all of that capacity, replacement with some amount of dispatchable baseload capacity is a reasonable approach to generation planning. Having a sound foundation of baseload capacity to meet MISO PRM requirements and serve customers assures reliable service and will allow Vectren South over time to add renewable resources.

We further note the significant risks faced by customers from delay to allow time for additional analysis. Vectren South must either retire, or make significant investments in its coal-fired generation facilities by 2023. Mr. Games' Attachment WDG-3R demonstrates that there is insufficient time to require Vectren South to go through another IRP and CPCN proceeding and then construct a new CCGT to meet this deadline. While we are not prejudging that a CCGT would be the result of that analysis, we have extensive evidence before us in this proceeding to conclude that a CCGT is the best option. Further delay risks losing the lead time needed to construct baseload resources such as the CCGT. Where a utility has engaged in robust modeling with sensitivity and risk analysis with full knowledge that there is a looming environmental deadline it faces, avoiding making a decision and risking relying on market purchases under these circumstances is unreasonable. As the Company's witnesses explained and the modeling shows, all plans to replace coal units which have provided 100% of baseload capacity for decades entail the expenditure of nearly $1 billion. Based on this modeling, the decision to select reliable on-system technology to meet this capacity need is reasonable.

The OUCC alleged that Vectren South should have considered modifying Brown Units 1 and 2 to burn natural gas rather than coal as a generation resource in its IRP modeling. Vectren

South's 2016 IRP did evaluate (but did not select as a low-cost option) converting Culley Unit 3 to burn on natural gas. Given that the Brown units are not as good a candidate for conversion as Culley 3, other gas conversions were not originally modeled. Vectren South witness Lind prepared updated modeling on rebuttal that considered Brown gas-refiring generation scenarios. Those scenarios were relatively more expensive than Vectren South's preferred portfolio. Petitioner's Exhibit No. 6-R, p. 9. The gas conversion scenarios became even more relatively expensive when Vectren South's 100% wholesale revenue sharing proposal was factored into the modeling, as confirmed in a response to the Commission's Docket Entry questions for further gas conversion modeling. Petitioner's Exhibit No. 21. In each case, Vectren South's preferred portfolio is a lower cost option. Mr. Games further described several risks that arise from relying on a coal-to-gas conversion as an electric utility's primary base load generating unit. Petitioner's Exhibit 4-R, p. 17-20. Such units have very high heat rates and poor dispatch rates. Based on the evidence, Vectren South has exercised its reasonable judgement in not proposing to re-fire Brown to operate on natural gas.

Substantial evidence therefore demonstrates and we find that Vectren South has evaluated the CCGT against other reasonable generation alternatives, including sensitivities, and also included DSM/EE levels that are consistent with the targets approved in our December 28, 2017 Order in Cause No. 44927. The analysis concludes that the CCGT is a least-cost, reliable resource alternative that meets Vectren South's resource needs and that it is in the public interest.

Vectren South proposes to duct-fire the CCGT. The duct-firing of the CCGT will allow it to provide an additional 150 MW of peaking capacity. Other parties objected to the size of the CCGT as duct-fired, contending that 850 MW (700 MW of baseload and 150 MW of peaking) was too much. On rebuttal, Mr. Chapman explained that Vectren South's proposal can be viewed as a request for two CPCNs in the alternative – one with the duct-firing that provides 150 MW of peaking capacity or one without the duct-firing. He explained that firing the unit only adds $15 million in incremental cost, from which 150 MW of peaking capacity is obtained. He testified that Vectren South will commit today, well in advance of a future rate case, to flowing 100% of wholesale sales revenues from the CCGT to customers, which assures customers receive all of the benefit from this incremental investment. He explained, however, that if the Commission ultimately determines not to approve the firing, then the 700 MW of baseload capacity from the unfired CCGT will only produce a surplus over MISO Planning Reserve Margin of 51 MW by 2025 (the year after it is placed in service). By 2032, the unfired CCGT would leave Vectren South below its PRM. Petitioner's Exhibit No. 1-R, pp. 15-16. And if Vectren South adds significant new customer load, it will not have any surplus capacity available to serve that load.

We must therefore decide which of the two versions would be more in the public interest. Firing is a very cost-effective means of obtaining additional capacity from the Company's CCGT. Mr. Games testified that duct-firing the CCGT allows the Company to secure a 21% increase in the total unit output for an approximately 2% increase in cost. Petitioner's Exhibit No. 4, p. 12. The duct-firing cannot cost effectively be added after the unit is constructed. Other parties criticized the size of the CCGT on the basis that it provided Vectren South generation capacity exceeding its needs over the planning horizon. As Mr. Games' Attachment WDG-4R demonstrates, this surplus capacity is attributable to the fired portion of the unit (if the CCGT is not fired, the CCGT very closely matches Vectren South's capacity needs). And as noted in an effort to resolve these concerns, Vectren South committed to changing its wholesale power sales sharing mechanism in its next rate case to provide 100% of its wholesale capacity and energy savings to customers. Currently, Vectren South customers only receive 50% of wholesale power sales revenues as a deduction to their fuel adjustment clause charges. Petitioner's Exhibit 1-R, pp. 16-17. This has the effect of further reducing customer costs.

Because of the nominal cost of adding duct firing to the CCGT, we find it is reasonable for Vectren South to construct the facility with duct-firing. This provides very low cost capacity that will be available to serve growth and can be utilized to further reduce costs for Vectren South customers through wholesale sales margins. Our finding is premised on Vectren South's commitment to share all of the wholesale power energy and capacity revenues generated by the CCGT with customers in its next base rate case.

In an effort to justify further investment to prolong the life of Vectren South's coal units despite the IRP modeling outcome, the Coal Parties submitted testimony that in times when severe weather events occur, coal units with on-site coal piles are more resilient than a CCGT unit that relies on gas delivery via a pipeline system, and therefore are better able to continue to generate power. To support this theory, the coal witnesses argued that coal units performed better than gas units during two recent hurricanes and the winter bomb cyclone in the northeast. The evidence offered by these witnesses was a report that during the bomb cyclone PJM saw an increase in reliance on coal generation. Both Vectren South and the Joint Intervenors submitted evidence to refute the claim that coal units are more resilient than gas units. Prior to the hearing in this proceeding, Vectren South witness Smead authored a study commissioned by the Natural Gas Council (NGC Study) that examined these three weather events and found that gas generation performed reliably throughout all three events. During the two hurricanes in the South, the only power generation failures were the result of electric grid issues, not gas pipeline failures. With respect to the bomb cyclone, all gas generators in PJM that had subscribed and paid for firm pipeline service continued to receive gas and generate power. The non-utility gas plants that relied on interruptible pipeline service were subject to interruption. PJM reported an increase in coal generation during the bomb cycle, but also confirmed that gas generation with firm gas service remained on line. As a result, these weather events do not support the proposition that coal units are more apt to run than gas units during severe weather events. Moreover, Mr. Smead explained that while PJM continues to struggle with a lack of pipeline capacity in many areas; in contrast central MISO where Vectren South is located has an abundance of pipelines providing a diversity of delivery routes from multiple supply basins, and thus is even less susceptible to any delivery problems. Vectren South also confirmed that it would secure firm pipeline capacity to serve its baseload unit.

Vectren South also explained the benefits of siting the CCGT at Brown. Given the large volume of gas required to supply the CCGT, there is a need to build a new lateral pipeline to connect the CCGT to Texas Gas Transmission's pipeline in Kentucky. While this cost was reflected in the IRP modeling, in this proceeding Vectren South has not asked for any findings on recovery of the cost of this lateral pipeline. Because no relief has been requested at this time in terms of project approval or cost recovery, there are no findings pertaining to the lateral required in this proceeding. However, given the significance of the $87 million investment and its integral relationship to Vectren's pending request for a CPCN in the present case, it is appropriate for the

Deleted: Rather, Vectren South provided a construction cost estimate and explained why it made sense to have its gas utility own and maintain the pipe and then bill Vectren South-Electric to recover that cost over time. Vectren South explained that its Indiana gas utility affiliate has this relationship in place with Duke and IPL to serve CCGTs located at Edwardsport and Eagle Valley respectively. The opposing parties take issue with whether the project might be less expensive if built by Texas Gas, whether the project will ultimately be competitively bid, and whether having the gas utility own the lateral somehow creates affiliate issues. In response, Vectren South explained that it obtained an estimate from Texas Gas that exceeded its own estimate and that it will use a bid process to select a contractor to build the pipeline. Vectren South also confirmed that it would obtain approval of the contract, including costs, between the electric and gas utilities and therefore all terms would be available for review at the appropriate time. We understand that this type of dedicated use pipeline is frequently built by the LDC in the area to serve the generation unit. There are reasons for this given the LDC's experience and expertise in building and operating transmission pipelines. The only difference here is the fact that the LDC and Vectren South- Electric are affiliated, but given the review that will occur, that does not mean there will be harm to customers. Regardless, the pipeline cost was included in the IRP, and

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Commission to discuss its impact on ratepayers as part of this proceeding. The evidence presented demonstrates that the cost of the pipeline will not move with natural gas prices or LMP market electricity prices, and its size or capacity is dependent with the maximum capacity of the CCGT. Yet Vectren currently anticipates recovering this fixed cost 100% on energy. Vectren's plan is inconsistent with fundamental principles of allocating costs according to cost causation. Further, allocating the fixed cost of this resource on an energy or volumetric basis may impair the economic justification of this investment to customers. The Company has acknowledged that there are multiple ways that assets could be viewed and allocated to be able to contemplate both the fixed and variable nature of the cost and justification of this facility. Accordingly, when seeking recovery of the lateral pipeline from ratepayers, Vectren should structure its proposal consistent with cost causation principles.

Finally, it is reasonable to consider the potential rate impact upon the public when considering whether a proposal is suited for the public need. Importantly, when contemplating the potential rate impact, we cannot look solely at the potential effect on rates from the incremental capital spend from the proposed CCGT. As we have noted, Vectren South has reasonably concluded that 730 MW of coal-fired baseload capacity should be retired. That capacity must be replaced, and the replacement will come at a cost. If not the CCGT, then some other alternative source of generation would need to be pursued, and that alternative source would also have an effect on rates. Vectren South did not present a rate impact analysis, but Mr. Swiz testified that the modeling produced an estimated revenue requirement that enables an evaluation of the potential rate impacts of the various scenarios. Tr., H-41; Petitioner's Exhibit No. 23C. The CCGT is part of all portfolios with the lowest revenue requirement for customers. He testified that the difference between the revenue requirement impact in 2024 of Vectren South's preferred portfolio and the least costly gas conversion option was minimal. Over a very short period of time, such other plans produce a higher revenue requirement. We have reviewed the modeling files and confirmed this to be true. Vectren South will be required to either retire its coal-fired generation fleet in 2023 or make substantial investments in the units to keep them operating beyond 2023. All of the portfolios to replace coal evaluated required investment that would impact rates around 2023.

Based upon the evidence, we find that the public convenience and necessity require the construction of the 850 MW duct-fired F-class 2x1 CCGT as proposed by Vectren South.

iv. *Competitive Procurement.*

Indiana Code § 8-1-8.5-5(e)(1), provides as follows:

> Before granting a certificate to the applicant, the commission:
>
> (1) must, in addition to the findings required under subsection (b), find that:
>
> (A) the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable; and

(B) if the applicant is an electricity supplier (as defined in IC 8-1-37-6), the applicant allowed or will allow third parties to submit firm and binding bids for the construction of the proposed facility on behalf of the applicant that met or meet all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on which the proposed facility becomes commercially available; and

(2) shall also consider the following factors:
(A) Reliability.
(B) Solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers.

The applicant, including an affiliate of the applicant, may participate in competitive bidding described in this subsection.

In this section, subpart (1)(A) addresses the cost estimates, and subpart (1)(B) addresses competitive procurement for the proposed facility. Subpart (2) then addresses reliability and solicitation of proposals for alternative sources of power. OUCC witness Alvarez testified that Vectren South had not complied with Indiana Code § 8-1-8.5-5 because the cost breakdown was not the result of competitively bid engineering, procurement, or construction contracts. Witness Aguilar further testified that Vectren South had not yet secured a manufacturer, chosen an exact type of CCGT, or issued any type of bid for this specific project. A careful reading of the language reveals that the OUCC is confusing these subparts.

Subsection (1)(A) addresses the "estimated costs". This subpart does not require competitive bidding for the actual facility; rather, it requires that the cost estimates "of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement or construction contracts." In other words, it asks how the cost estimates were derived. Those cost estimates are to be based, to the extent practicable, on competitive procurement. This language does not require that the actual facility to be built has been bid before we issue the CPCN. Indeed, such a reading would make the statute unworkable – these cases can take a year or longer to be decided and even longer if we consider the time during which the proposal is being developed. We cannot expect reliable bids to be received for the actual project for purposes of building the cost estimates. Here, upon completion of conceptual design, Black & Veatch solicited and evaluated competitive bids for all equipment and construction. Petitioner's Exhibit No. 10, p. 36. This addresses the "procurement" and "construction" aspects of subpart (A). As to the "engineering" aspect, Ms. Fischer testified that it is not commercially practicable to competitively bid the engineering piece, because Black & Veatch is an engineering firm. She testified that its competitors are not going to provide Black & Veatch with bids for engineering services. Instead, Black & Veatch was capable of providing reliable estimates for those contracts, and that her estimate was within a +/- 10% range. *Id.* at p. 37. No party presented evidence rebutting her testimony that the cost estimates were based on competitive procurement and competitive construction bids. Further, no party rebutted her testimony that it was not commercially practicable for an engineering firm to solicit engineer bids. Accordingly, we find that subpart (A) has been satisfied and that the cost estimates of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts.

Subpart 1(B) is the issue to which the OUCC's objection is addressed. This subsection requires "firm and binding bids for . . . the proposed facility." This is where a utility must have selected a manufacturer and chosen an exact type of CCGT. The purpose of subsection 1(B) is to assure that the actual cost to be incurred (as opposed to the estimated cost) will be reasonable. Notably, however, the bidding need not be completed *before* the issuance of the CPCN. Instead, what is required is that the petitioner "*will* allow third parties" to bid. (Emphasis added.) Witness Games testified on direct that the Company will use competitive bidding for the actual construction. He outlined in detail the process by which the EPC contractor will be selected. Petitioner's Exhibit No. 4, pp. 32-33. Accordingly, we find that Vectren South will allow third parties (EPC contractors) to submit firm and binding bids for the construction of the proposed facility on behalf of the applicant that meet all of the technical, commercial, and other specifications required by Vectren South so as to enable ownership of the proposed facility to vest with Vectren South no later than the date on which the proposed facility becomes commercially available.

The final provision of subsection (e) is that we are also to consider the following factors: "(A) reliability, (B) solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers." Witness Luttrell described the RFP process. As he explained, Vectren South sought proposals (either PPAs, sales) of 600 MW of dispatchable capacity located in MISO Zone 6. The size was based upon Vectren South's needs as demonstrated in the IRP; that it be "dispatchable" is in recognition that Vectren South is replacing baseload capacity and therefore needs the replacement capacity similarly to be dispatchable; that it be located in Zone 6 is to assure that the capacity would count towards Vectren South's MISO local clearing requirement. Other parties raise several issues concerning the RFP. The first issue raised on cross examination related to the all-source RFP conducted by NIPSCO as part of its 2018 IRP. As we have already explained, we do not have before us competent evidence of the results of that RFP and, even if we did, we do not have sufficient context to tell us whether it compares on an apples to apples basis with Vectren South's modeling. No party suggested during the stakeholder process for Vectren South's 2016 IRP that Vectren South should conduct an all-source RFP.

Another objection raised to the RFP was the size, 600 MW. The size was a function of Vectren South's need. Further, Vectren South's modeling conducted in connection with the 2016 IRP demonstrated that the lowest cost alternative would be supplied by a large CCGT. It must be remembered that Vectren South is retiring all but 270 MW of its baseload capacity. The size of the resource requested by the RFP is appropriate.

The next objection was the limitation that Respondents be located in Zone 6. This is because, to count towards the local clearing requirement for MISO, the generation must be located in Zone 6 (Indiana). We find this to be a reasonable restriction. If Vectren South were to enter some arrangement with an RFP respondent for long-term capacity and later be subject to a penalty for failure to meet the local clearing requirement, it would be unreasonable. Accordingly, we have considered reliability and solicitation by Vectren South of competitive bids to obtain purchase power capacity and energy from alternative suppliers.

6. Conclusion on Vectren's Request for a CPCN for the CCGT. Vectren South must either make substantial investments at every coal-fired baseload unit or retire 1,000 MW of capacity – literally all of its baseload capacity. The modeling confirms that regardless of the overall portfolio of resources, the lowest cost option for customers always includes a 700 MW F-class 2x1 CCGT which is duct-fired to provide an additional 150 MW of peaking capacity. We have received no modeling, no credible assumptions, and no alternative pricing which changes this result. We have made the required findings under Ind. Code § 8-1-8.5-4 and 5. We therefore find that a CPCN should be issued for Vectren South's proposed 850 MW duct-fired F-class 2x1 CCGT.

7. Ongoing Review of CCGT construction. Indiana Code § 8-1-8.5-6(a) addresses the Commission's review of facilities under construction as follows:

> In addition to the review of the continuing need for the facility under construction . . . the commission shall, at the request of the public utility, maintain an ongoing review of such construction as it proceeds. The applicant shall submit each year during construction, or at such other periods as the commission and the public utility mutually agree, a progress report and any revisions in the cost estimates for the construction.

Vectren South requested the Commission to conduct such ongoing review of the CCGT. Vectren South proposes to submit construction progress reports, updated cost estimates, any revisions to the cost estimates and other information regarding the implementation of the Projects to the Commission on a quarterly basis during construction. Petitioner's Exhibit No. 4, p. 38.

While we appreciate Vectren's proposal to provide the Commission with frequent reports, we must also ensure that enough time is given between tracker proceedings to allow for adequate review of the Company's progress report.[9] Accordingly, we will issue orders in docketed proceedings semiannually, rather than quarterly, as we did for the construction of IPL's Eagle Valley CCGT. *Indianapolis Power & Light Co.*, Cause No. 44339 (IURC 5/14/2014), p. 30. If Petitioner nevertheless wishes to submit information to the Commission and the parties more frequently, it may do so within the context of the pending docketed proceedings. We find that Vectren South shall report at least semiannually to the Commission information related to the CCGT including safety, scope, schedule, and Owner's cost contingency, as well as the: a) manufacturer, model number and operational characteristics of the turbine generator; b) anticipated total annual megawatt hour output for the CCGT; c) the name of the CCGT Contractor; d) update on cost estimate; and e) update on the natural gas transportation and lateral pipelines.

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The initial CCGT quarterly reports shall be filed by December 30, 2019 as a compliance filing in this Cause. The final project report shall contain the following information: a) the actual

[9] In another case involving ongoing review of a large generating unit, the parties recognized that even semi-annual petitions can present challenges. *See Duke Energy Indiana*, Cause 43114 IGCC 15 (08/24/2016) at 79.

total cost of construction; b) the total megawatt output for the facility; and c) the actual in-service (commercial operation) date for the facility.

8. **Accounting and Ratemaking Issues Associated with CCGT.** Vectren South plans to recover the costs of the CCGT from ratepayers in its next base rate case. Yet Vectren is seeking preapproval of the cost estimate of the CCGT in this proceeding, and therefore we find it appropriate to consider the financial impact as a whole on ratepayers in this proceeding as well.

A. Petitioner's request to defer depreciation and post-in-service carrying costs.

Vectren South requests accounting authority, starting with the date the CCGT is placed in service, for the deferral of depreciation and financing costs (post-in-service carrying costs, or "PISCC") related to the CCGT investment until such time as those costs and the CCGT investment are reflected in Vectren South's retail electric rates. The estimated construction costs for the CCGT are approximately $781 million compared to estimated electric rate base as of December 31, 2016 of $1.4 billion.

Mr. Swiz testified an estimated $26 million of annual depreciation expense and approximately $61 million of incremental financing costs (both debt and equity) will be unrecoverable through rates as a result of the ceasing of AFUDC upon the plant being placed in service. Vectren South witness M. Susan Hardwick testified that the depreciation deferral and continuation of the accrual of carrying costs post in service will not only alleviate the impact on the Company's financial results, but will give investors comfort in the reasonableness of regulation in Indiana, which leads to a willingness on the part of investors to continue to make capital available to Vectren. Petitioner's Exhibit No. 3, p. 5.

OUCC witness Blakley recommended that the post-in-service AFUDC rate be used until new rates are implemented, rather than the current approved weighted average cost of capital ("WACC") as the basis for PISCC accrual. On rebuttal, Mr. Swiz testified Vectren South's request is consistent with Commission practice of approving the use of the WACC and cited numerous orders approving use of WACC for the accrual of PISCC on investments after their in-service date but prior to inclusion in the utility's rates. He also testified that use of the post-in-service AFUDC rate is inconsistent with Federal Energy Regulatory Commission ("FERC") guidance. Mr. Swiz explained that AFUDC captures short-term financing costs incurred during a construction cycle whereas WACC captures the long-term cost of capital for the utility. He stated the magnitude of the CCGT will require the use of long-term financing and therefore the WACC rate represents the most accurate cost of this financing for the utility.

Petitioner has presented evidence claiming that the Company will experience a negative impact on its earnings during the time between the date the CCGT is placed in service and the issuance of an order of this Commission authorizing recovery in Vectren South's rate of a return on the CCGT and depreciation expense. During this interim period Vectren South will also not be recovering carrying costs of the construction project. Vectren South's requested accounting treatment would allow it to offset the erosion to monthly pre-tax earnings by approximately $48 million due to the deferral of the depreciation expense and continuation of the debt component of PISCC. The Petitioner's proposal to defer depreciation and continue accrual of carrying costs

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The appropriate rate for post-in service carrying charges is an issue we have frequently addressed. Numerous Orders have concluded the appropriate rate is the WACC. *Duke Energy Indiana, Inc.*, Cause No. 44367 (IURC 6/25/2014), p. 14, 2014 Ind. PUC LEXIS 180, *35; *Indianapolis Power & Light Co.*, Cause No. 44339 (IURC 5/14/2014), p. 35, 2014 Ind. PUC LEXIS 132, *103 (citing orders); *Northern Indiana Pub. Serv. Co.*, Cause No. 44340 (IURC 1/29/2014), p. 11, 2014 Ind. PUC LEXIS 23, *28. There are also several orders involving Vectren South that were cited at page 3 of Mr. Swiz's rebuttal testimony, *Southern Ind. Gas & Elec. Co.*, Cause No. 44927 (IURC 12/28/2017), Cause No. 44909 (IURC 8/16/2017), Cause No. 44910 (IURC 9/20/2017), Cause No. 44645 (IURC 3/23/2016), Cause No. 44446 (IURC 1/28/2015), and Cause No. 44429 (IURC 8/27/2014). ¶

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post-in-service is designed to provide a bridge between the date the CCGT is placed in service and the date the CCGT is placed into base rates. See Hardwick Direct at 5.

We do not find Petitioner's testimony persuasive. Petitioner's testimony disregards the Company's own ability to mitigate or even eliminate the effects of regulatory lag by timely filing a rate case. The General Assembly provided a statutory means to address the issues identified by Petitioner when it enacted I.C. § 8-1-2-42.7 in 2013. Section 42.7(d) enables a utility to utilize either a forward-looking or hybrid test year in addition to the traditional option of a historic test year. In addition, Section 42.7(f) provides that temporary rates may go into effect three hundred days after the utility files its case in chief. Thus, the length of time for any bridge period—or indeed, the existence of a bridge period at all—is entirely within the control of Petitioner.

We note that Petitioner has not filed a base rate case since 2010, and therefore the 10.4% ROE applicable to Petitioner's base rates has not changed since that time. As discussed in more detail in the MATS projects section, Industrial Group witness Mike Gorman explained that a 10.4% ROE is significantly higher than authorized returns of electric utilities around the country as well as for Indiana utilities. Petitioner's return has become excessive with the passage of time in relation to current market conditions, and will likely be adjusted downward on Petitioner's next base rate case. However, if Petitioner were permitted to defer depreciation and the continuation of accrual of carrying costs post-in-service, then the incentive of Petitioner to promptly bring a rate case to roll the CCGT into rates would be significantly reduced.

For the reasons explained above: (1) we deny Petitioner's request to accrue PISCC, at Vectren South's current approved WACC (Cause No. 44910-TDSIC2) on the CCGT from the date it is place in service until the date of a Commission order authorizing recovery of a return in Vectren South's rates; (2) we deny Petitioner's request to defer the accrual of depreciation expense on the CCGT from its in-service date(s) until the date of a Commission order authorizing recovery in Vectren South's rates of depreciation expense; (3) we deny Petitioner's request to record PISCC and deferred depreciation in a regulatory asset in Account 182.3 Other Regulatory Assets; (4) we deny Petitioner's request to amortize the regulatory asset as a recoverable expense for ratemaking purposes over the estimated life of the CCGT commencing on the date of the order authorizing recovery in Vectren South's rates of a return on the CCGT and depreciation expense; and (5) we deny Petitioner's request to include the unamortized portion of the regulatory asset in Vectren South's rate base upon which it is permitted to earn a return.

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B. Stranded Assets of Coal Generating Units after 2023.

i. Evidence.

Mr. Gorman testified that Vectren is embarking on a period wherein it will be incurring significant resource costs for both new generating capacity and abandoned resource cost (i.e., undepreciated or "stranded" assets). Gorman Direct at 7. He noted that Vectren intends to seek recovery of these stranded assets. *Id.* at 6 (citing Chapman Direct at 12). He testified that the abandoned plant costs of the coal-fired plants are significant, and have been exacerbated by Vectren's past resource decisions and the timing of the current proposal. *Id.* at 13. In light of the overlap of costs associated with new generating costs and the stranded assets, Mr. Gorman recommended that the Commission implement specified regulatory procedures and accounting mechanisms to protect customers against this significant cost exposure, including developing a plan to mitigate the impact of stranded costs. *Id*. at 8, 13.

Mr. Gorman testified that it is appropriate to consider the ratemaking treatment to address and mitigate the stranded cost issue in this proceeding because Vectren is seeking preapproval for the CCGT costs at this time. *Id*. at 13. Mr. Gorman identified several options to mitigate the impact of the costs of stranded assets, which assets are no longer used and useful, including (1) requiring that stranded costs be amortized without a return or with a return calculated based on the cost of long-term debt; (2) disallowing the recovery of a defined portion of the stranded costs; and (3) utilizing a special financing instrument such as a securitization bond. Gorman Direct at 14.

During hearing, Mr. Swiz testified that Vectren anticipates that ratepayers will be facing several hundred million dollars of stranded assets in 2023 when Vectren retires the Brown generating units, Warrick 4, and Culley 2. He testified that Vectren currently projects the amount of the stranded assets to be $270 million, but acknowledged that the number may even be higher than that. Mr. Swiz further acknowledged that there is a lot of uncertainty around the level of spend that will be necessary to keep these coal generating units operating through 2023. Tr. at H:24-25. Tr. at H:22-25; IG CX-1.

ii. Commission Findings.

Integrally related to Vectren's request for authority to incur $781 million of CCGT costs that will ultimately be passed along to ratepayers is Vectren's concurrent proposal to retire Brown Units 1 and 2, Warrick 4, and Culley 2. Vectren estimates that in 2023 when these units are retired and the CCGT goes into service, it will have an estimated $270 million in stranded assets remaining on those coal generating units. Vectren has indicated that it intends to recover these stranded costs from ratepayers starting in 2023, simultaneously with the commencement of charging ratepayers for the $781 million CCGT costs. Together, the combined cost that Vectren proposes to collect through rates associated with its old and new generating assets in 2023 **exceeds** one billion dollars (not including the additional $87 million for the gas lateral pipeline that will also be needed). Yet despite the high cost of Vectren's plan, Vectren has offered no proposal for mitigating the impact of this cost on ratepayers.

We are required to make a determination in this proceeding regarding whether Vectren is entitled to a CPCN to incur the costs for the CCGT. We reject Vectren's invitation to preapprove the costs of the CCGT at this time, only to determine at a later date—after such costs have already been incurred—how the costs can be managed to reduce the impact on ratepayers. Accordingly, we find that any stranded assets of the retiring coal generating units remaining after the CCGT is placed in service shall be amortized without a return, over a period of not less than 20 years. However, the Commission would consider a plan providing for accelerated recovery in the event that it does not increase costs to customers.

C. Contractual Protections for Ratepayers

i. Evidence.

Mr. Gorman testified concerning the risk of cost overruns to construct the CCGT. He observed that Vectren's decision to self-build the CCGT potentially exposes the utility to enhanced risk of cost overruns, but that these risks can be mitigated by appropriate contractual provisions that shift the risk of cost overruns to Vectren's major equipment suppliers, and/or engineering procurement and construction ("EPC") contractors. Gorman Direct at 18:16-22. Mr. Gorman testified it is common for utilities to mitigate the risks of constructing generating resources by placing certain development risks on major equipment suppliers and EPC contractors. *Id*. at 20. Mr. Gorman recommended that the Commission require Vectren to demonstrate reasonable efforts to mitigate the development cost uncertainty and development risk through contractual protections with its major equipment suppliers, or engineering procurement contractors while still resulting in a reasonable and prudent CCGT resource cost. *Id*. at 21.

Mr. Gorman further noted that Vectren has touted the expected performance characteristics of the CCGT—including its thermal efficiency and ability to quickly ramp up and down in response to MISO directives—to justify the significant cost of the CCGT. Gorman Direct at 21-22. In order to achieve these expected performance characteristics, Mr. Gorman recommended that Vectren have clear performance obligations in its contracts with its EPC/supply contractors. Mr. Gorman testified that the contracts should provide Vectren with a contractual right to damages in the event that the CCGT fails to perform as expected, and such damages should then be used to reimburse Vectren customers. See Gorman Direct at 22-23.

In rebuttal, Vectren agreed to consider Mr. Gorman's recommendations. Games Rebuttal at 38:7-14. However, though he indicated that Vectren "leans towards and desires a fixed price EPC contract," he testified that Vectren has not decided what method it will utilize for the EPC contract. *Id*. at 39:1-11. Mr. Games explained the Company's reticence to commit to a fixed price EPC contract, stating that "Knowing that EPC contractors will add a premium for taking on the risk associated with a firm price, Vectren South will evaluate whether the benefits of a fixed price bid are justified by its costs." Games Rebuttal at 39:1-11; see also Tr. at E:68. During the hearing, Mr. Games further explained that "if you ask for a firm price bid, EPC contractors are going to raise their price. They're going to put a contingency in there because they don't know what can happen so they're going to make sure to cover themselves…" Tr. at E:70.

Mr. Games testified that the EPC portion of the contract is $582 million of the overall $781 million CCGT estimate. Games Direct at 15. During the hearing, Mr. Games confirmed that the $582 million EPC portion of the cost estimate contains its own contingency, and the calculation of the $582 million is based on the assumption of a fixed price EPC contract. Tr. at E:60-61; E:70-71. Mr. Games identified the precise amount of contingency included in the EPC portion of the contract during a confidential portion of the hearing. Tr. at E:67 (in camera); IG Confidential CX-3C.

Mr. Games was asked during the hearing what would occur if Vectren elected not to execute a fixed price EPC contract, and subsequently cost overruns occurred that could have been prevented by a fixed price EPC contract. Mr. Games testified that Vectren could not make the decision of whether it would seek recovery from ratepayers in that situation until Vectren evaluated the responses by the EPC contractors. Tr. at E:68-70.

ii. Commission Findings.

Our approval of Petitioner's CPCN is based on the Company's representations about the cost and performance of the CCGT. Both of these issues were extensively litigated between Petitioner, the OUCC, and several intervenors in this case. During the hearing, Mr. Games acknowledged that Petitioner's cost estimate, including the contingency built therein, is a material consideration in the determination of whether a CPCN ought to be granted. Tr. at E:72. We agree.

We find that ratepayers should be protected from the possibility that the CCGT will fail to meet the expectations upon which our grant of the CPCN was based. Furthermore, we find that the appropriate contractual provisions of the CCGT construction should be considered *prior* to execution of the contract, rather than waiting until the ongoing review process (after any problems have arisen and after the contract has already been executed) as Vectren has suggested.

Petitioner's current cost estimate for the CCGT has an accuracy of +/- 10%. The $582 million EPC portion of the overall $781 million cost estimate contains its own contingency, and is based on an assumption of a fixed price EPC contract. The amount of contingency[10] is relatively low in comparison to the overall $582 million EPC contract. Moreover, we note that even in the absence of a fixed price EPC contract, some level of contingency might have been included in the EPC cost estimate. Thus, the incremental additional cost to execute a fixed price EPC contract, versus a non-fixed price EPC contract, may be even less than the already low contingency figure presented as the amount of contingency in this case.

A properly executed fixed price EPC contract shields ratepayers from cost overruns during the construction of a capital project, even in the absence of imprudence on behalf of either the EPC contractor or the utility.[11] Prudency is required not only during the construction phase of a project, but also in the execution of contracts between the utility and its contractors. As we have previously explained, it is not reasonable for ratepayers to pay for the imprudent actions of a utility's contractors that a prudent contract would have placed on such contractors. *Duke Energy Indiana*, Cause 43114 4S1 (IURC 12/27/2012) p. 122. Under the circumstances in this case, we find that it would be imprudent for Petitioner not to execute a fixed price EPC contract for the CCGT. Accordingly, we find that our approval of Petitioner's CPCN in this proceeding is conditioned upon Petitioner executing a fixed price EPC contract at a price no higher than $582 million. In addition, we agree with Mr. Gorman that any EPC contract should have clear performance obligations that provide Petitioner with a contractual right to damages in the event that the CCGT fails to perform consistent with Petitioner's representations in this proceeding. If that event occurs, such damages should be used to reimburse Petitioner's customers.

Deleted: Other parties suggested we impose conditions – such as to cap construction costs, and to limit the future reflection through rates on a "levelized" basis. In addition, Industrial Group Witness Gorman suggested we should condition the CPCN on future ratemaking treatment associated with any remaining net book value associated with retiring coal plants. This is not a general rate case, and Vectren South has made no proposals and requested no relief with respect to such net book value, and so we find that Mr. Gorman's requests are premature. There will be a time to address such cost recovery, but that time is not today. We are only approving the construction costs up to the estimates; cost overruns are a matter to be addressed through ongoing review. The "levelized" recovery proposed by Mr. Gorman would pose generally accepted accounting principle problems and would violate Ind. Code § 8-1-2-6. We therefore find that the conditions suggested with respect to caps, performance guarantees, and future ratemaking should be rejected

[10] Vectren has indicated that the specific amount of the contingency included within the $582 million EPC portion of the cost estimate is confidential. This figure is shown in the in camera portion of the transcript at E:67, on IG Confidential CX-3C, and in the Industrial Group's Confidential version if its hearing brief.

[11] Regardless of the manner of contracting between a utility and its contractors, in no event may ratepayers be required to pay for any imprudence on behalf of either the utility or its contractors. The utility is ultimately responsible for its own actions and the actions of its contractors, as we have previously explained. *Duke Energy Indiana*, Cause 43114 4S1 (IURC 12/27/2012) p. 122.

9. **<u>CPCN Request for Culley 3 Compliance Project</u>**. As we have already explained herein, Vectren South's preferred portfolio includes not only the CCGT but also the construction of various environmental projects that Vectren South contends are needed so that Culley Unit 3 can continue to operate beyond 2023. Vectren South's petition seeks relief for these projects under Ind. Code ch. 8-1-8.4 as "federally mandated" projects. We will now proceed to consider the statutory elements and make our findings thereunder.

A. <u>Ind. Code ch. § 8-1-8.4 ("Chapter 8.4")</u>.

i. <u>Federally Mandated Requirements (Ind. Code §§ 8-1-8.4-5 and 8-1-8.4-6(b)(1)(A) and 8-1-8.4-7(b)(3))</u>. Ind. Code § 8-1-8.4-5 defines a federally mandated requirement to include "a requirement that the commission determines is imposed on an energy utility by the federal government in connection with any of the following: (2) The federal Water Pollution Control Act (33 U.S.C. 1251 *et seq.*)" and also includes "(7) Any other law, order, or regulation administered or issued by the United States Environmental Protection Agency, the United States Department of Transportation, the Federal Energy Regulatory Commission, or the United States Department of Energy."

The description of the Culley 3 Compliance Projects were set forth in the direct testimonies of Ms. Fischer and Ms. Retherford. The Culley 3 Compliance Projects consist of (1) conversion of the current wet bottom ash collection system to a dry handling bottom ash system; (2) installation of a spray dryer evaporator system; and (3) the closure of the Culley West ash pond and construction of a new lined process water and storm water retention pond in its place. This new retention pond will be constructed on the location of the existing ash pond due to space limitations. No party disputed that the dry handling bottom ash conversion or spray dryer evaporator system qualify as compliance projects to meet federally mandated requirements. The OUCC challenged whether the closure of the existing pond qualified for relief but did not contend that it was not federally mandated. For the reasons described below, we find that these projects all constitute compliance projects to meet Federally Mandated Requirements as those terms are defined in Ind. Code §§ 8-1-8.4-2 and -5.

Vectren South witness Retherford testified that the dry handling bottom ash system is required to comply with the ELG Rule, which was promulgated under the federal Water Pollution Control Act. <u>Petitioner's Exhibit No. 9,</u> p. 11. The ELG rule prohibits further wet handling of fly and bottom ash. This system will enable ash from Culley Unit 3 to be disposed of in a landfill, hauled back to a surface mine in accordance with applicable surface mining regulation or recycled rather than being washed into the ash pond as part of a water discharge.

Ms. Retherford further explained that the spray dryer evaporator system was necessary to ensure compliance with ELG-imposed limits on flue gas desulfurization ("FGD") wastewater discharge. She noted that this system functions effectively as a ZLD system and enables the Company to utilize the alternative ELG-imposed compliance date of December 31, 2023, and to meet future more stringent ELG wastewater discharge limits.

No party disputed that Vectren South's need to *construct* a new lined process and stormwater retention pond is required by a federally mandated requirement. Ms. Retherford testified that construction of a new, lined process and storm water retention pond is required to comply with the ELG Rule. As we have already noted, projects necessary to comply with the ELG Rule, promulgated pursuant to the federal Water Pollution Control Act (33 U.S.C. 1251 *et seq.*), constitute a federally mandated requirement. The only dispute, raised by OUCC witness Aguilar, pertains to Vectren South's plans to close the existing Culley West pond so that the new lined pond can be built at the site. Witness Retherford testified that there are two reasons the Culley West pond is closing: (1) the pond was taken out of service prior to the 2015 deadline and the CCR rule requires that it be closed by 2020; and (2) the current space limitations require that the new stormwater retention and process water pond be constructed on the current location. Thus, there is no dispute that costs associated with the construction of the new lined pond are incurred pursuant to a federally mandated requirement. The dispute is whether the costs to close the Culley West pond so that the new pond can be built on top of that location, also qualify as federally mandated costs.

The OUCC identifies three reasons closure costs for the Culley West pond should not be considered federally mandated costs. First, OUCC witness Aguilar contends that the Company has been collecting depreciation and asset retirement costs in base rates, which include the closure of ash ponds. Public's Exhibit No. 1, p. 28. However, Vectren South witness Retherford responded that finalization of the CCR rule on April 17, 2015 imposed more stringent requirements to close the ash pond. The CCR rule imposed an obligation to dewater, cap and/or remove ponded ash. Petitioner's Exhibit No. 9-R, pp. 24-25.

On rebuttal, Mr. Swiz stated Vectren South's existing depreciation rates include an estimated level of cost of removal that was designed well before the implementation of requirements to close the ponds in accordance with the environmental regulations described by Ms. Retherford. The assumed removal costs in the demolition study provided in Cause No. 43839 (Vectren South's most recent general rate case), estimated $1.1 million to close both of the Culley Ash Ponds based on cost of backfill, grading and seeding. By comparison, the estimate for closure of one ash pond in this proceeding is $19.969 million. Petitioner's Exhibit No. 13-R, pp. 6-7; Petitioner's Administrative Notice 1.

Consequently, we find that costs associated with CCR closure have not been included in Vectren South's depreciation rates, which were last updated prior to finalization of the CCR Rule.

Second, the OUCC contends that other utilities are not tracking pond closure costs as Federally-Mandated CCR Projects. Public's Exhibit No. 1, p. 28. Vectren South witness Swiz noted that no utility had proposed such recovery yet but that one utility specifically indicated that it would present closure related activities as recoverable under the Federal Mandate Statute. Petitioner's Exhibit No. 13-R, pp. 6-7. Mr. Swiz explained that Duke, IPL and NIPSCO did not ask for recovery of their pond closure costs in the proceedings Ms. Aguilar cited, and in fact the order in Duke's Cause No. 44765 specifically notes that Duke anticipates presenting closure related activities of existing surface impoundments and their associated costs in a future proceeding. Petitioner's Exhibit No. 13-R, p. 6, citing Order in Cause No. 44765 at 7. Each of the cases Ms. Aguilar cited were settled cases containing non-precedential language. Nevertheless, Mr. Swiz pointed out that the NIPSCO Order suggests that the OUCC agreed that closure costs can be recovered as federally mandated costs. Petitioner's Exhibit No. 13-R, p. 7.

Third, the OUCC contends that Vectren South should have presented alternative suitable locations to the West Pond for consideration. However, Ms. Retherford testified that the location was chosen because there was limited space at the Culley generating station. In other words, there was not an alternate location to explore. The statutory requirement to consider options does not require a utility to present alternatives that are not practical or feasible. Accordingly, we find the Culley 3 Compliance Projects are all federally mandated requirements and that Vectren South described them in its application.

ii. Projected Federally Mandated Costs (Ind. Code §§ 8-1-8.4-4, 8-1-8.4-6(b)(1)(B), 8-1-8.4-7(b)(2), and 8-1-8.4-7(b)(3). Energy utilities seeking recovery of Federally Mandated Costs must establish that the costs are incurred in connection with a compliance project, including capital, operating, maintenance, depreciation, tax or financing costs and describe the costs to be recovered. Ind. Code §§ 8-1-8.4-4 and -6(b)(1)(B). We have already found that the Culley 3 Compliance Projects constitute projects required by federally mandated requirements. Consequently, the costs associated with these projects constitute Federally Mandated Costs. These costs will consist of capital, operating, maintenance, depreciation, tax and financing costs. Vectren South identified the estimated costs to be recovered as Federally Mandated Costs. Costs associated with the dry handling bottom ash handling system and spray dryer evaporator system were identified by Vectren South witness Fischer. Petitioner's Exhibit No. 6, pp. 16-18, 26-28. Costs associated with the construction of a new lined process water and storm water retention pond were identified in Ms. Retherford's testimony. Petitioner's Exhibit No. 9, Attachment AMR-1. No party disputed the cost estimates for the Culley 3 Compliance Projects. Based on the evidence presented, we find that Vectren South has identified federally mandated costs and reasonably described those costs. Those total costs are $95 million, and they are hereby approved. Petitioner's Exhibit No. 4, p. 26.

iii. Compliance with Federally Mandated Requirements (Ind. Code §§ 8-1-8.4-6(b)(1)(C)) and 8-1-8.4-7(b)(3)). No party disputed that the Culley 3 Compliance Projects will allow Vectren South to comply with ELG and CCR or that ELG and CCR are federally mandated. The OUCC's objections related to appropriateness of recovery, which we have already addressed. We have already found that the ELGs and CCR Rule are federally mandated requirements within the meaning of Ind. Code §§ 8-1-8.4-5 and 8-1-8.4-6(b)(1)(A) and 8-1-8.4-7(b)(3). Based on the evidence presented, we find that Vectren South's Culley 3 Compliance Projects, will allow the utility to comply with the ELGs and the CCR Rule. Therefore, we find that Vectren South has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(C).

iv. Alternative Plans for Compliance (Ind. Code §§ 8-1-8.4-6(b)(1)(D) and 8-1-8.4-7(b)(3)). Ind. Code § 8-1-8.4-6(b)(1)(D) requires the Commission to examine "[a]lternative plan that demonstrate that the proposed compliance project is reasonable and necessary." Vectren South witness Diane Fischer testified about Black & Veatch's evaluation of the ELG Compliance Program for Culley to identify potential flue gas desulfurization (FGD) discharge water treatment alternatives and ash transport water alternatives that could be implemented to comply with the ELGs. She sponsored two written reports setting forth Black & Veatch's analyses of the alternatives. Ms. Fischer testified that each of the potential discharge treatment technology alternatives assessed by Black & Veatch were screened for design concept feasibility, capital expense and operating expense.

With respect to FGD discharge water treatment, two main treatment alternatives were considered, (1) FGD treatment and discharge; and (2) zero liquid discharge. Three technology types were evaluated within these two treatment alternatives: (1) for FGD treatment and discharge, physical/chemical pretreatment with biological treatment technology, (2) for ZLD, spray dryer evaporator technology, and (3) also for ZLD, brine concentrator/crystallizer technology. Ms. Fischer testified that multiple vendors providing such technologies were evaluated. A sensitivity analysis was then performed for each technology and vendor. Ms. Fischer's Discharge Treatment Report also included a cost assessment of all alternatives considered. Petitioner's Exhibit No. 10, p. 7. Ms. Fischer testified that Black & Veatch provided Vectren South with a final overall assessment of each technology and vendor offering based on Black & Veatch's analysis and the following attributes: (1) start-up/ramp up reliability; (2) technology readiness risk; (3) adaptability to sensitivity analysis scenarios; (4) operation and control risk; (5) heat rate impact risk; (6) number of operators; (7) capital and annual O&M costs; (8) susceptibility to future environmental regulations; (9) overall financial stability and credit rating. Black & Veatch ultimately recommended that Vectren move forward to a detailed engineering phase with SDE type technology if the maximum FGD wastewater flow rate of between 50 and 80 gpm is achieved through future testing and operations. Ms. Fischer explained the SDE solution ranks the highest among all technologies based on the attributes discussed above and the solution is economically viable and provides a zero discharge solution if the minimum FGD wastewater flow rate of between 50 and 80 gpm is achieved and is economically viable and provides a zero discharge solution if the maximum FGD wastewater flow rate of 80 gpm is achieved. The conceptual design evaluation indicated the SDE can be feasibly located and tied into the existing equipment at Culley. In addition, Ms. Fischer stated the ZLD solution provides certainty that any future change in EPA regulations would not apply at Culley since there would be no discharge of FGD wastewater.

With respect to ash transport, Ms. Fischer described Black & Veatch's analysis to identify alternative ash transport solutions that could be implemented at Culley to comply with ELG requirements, focused specifically on identifying options for removal and dewatering of bottom ash from the Culley Unit 3 boiler with truck transport and disposal of the dry material at an off-site location. Black & Veatch evaluated two categories of technologies: (1) dry conversion of the bottom ash system and (2) closed loop wet sluicing system. For dry conversion system, Black & Veatch evaluated a submerged chain conveyor under the existing bottom ash hopper. For the closed loop wet sluicing system, Black & Veatch evaluated both a dewatering bunker and a remote submerged chain conveyor. In comparing all technologies, Black & Veatch used the following quality attributes to select the preferred treatment: technical feasibility; total installed cost, O&M cost, estimated additional manpower ("FTE"), estimated footprint, major equipment, advantage, disadvantages and reliability. Ms. Fischer's testimony discussed in detail the advantages and disadvantage of each alternative. Black & Veatch prepared cost estimates for all technologies considered for addressing ash transport water. Black & Veatch ultimately recommended the submerged chain conveyor for Culley 3 compliance with ELG requirements, due to the complexity of design and comparatively higher installed cost of the other alternatives.

The only evidence offered in opposition as being an alternative plan was the OUCC's conclusory statement about possible alternative locations for the new lined pond. As we have previously found, the chosen site was selected because there are no alternative locations.

While the Commission gives significant weight to cost-effective planning and decision making when considering alternatives, the Federal Mandate Statute does not require that a utility demonstrate that the chosen compliance plan is the least cost option. Consistent with the Commission's finding in IPL's recent proceeding, Cause No. 44794 (IURC 4/26/2017), p. 30, 2017 Ind. PUC LEXIS 114, *92, that "it is important that the Petersburg Station is able to continue to operate on coal and protect customers from potential price volatility in the gas markets", a reasonable alternative can be, and often is, a solution that includes risk balancing through a diversified portfolio.

Based on the evidence presented, we find that Vectren South considered alternative plans for compliance with the ELGs and the CCR Rule. The evidence shows that the Culley 3 Compliance Projects are reasonable and necessary.

v. Useful Life of the Facility (Ind. Code §§ 8-1-8.4-6(b)(1)(E) and 8-1-8.4-7(b)(3)). Mr. Games testified that the investments in the Culley 3 Compliance Projects will allow for the continued operation of Vectren South's most efficient coal fired unit. Ms. Retherford described the environmental regulations requiring the Culley 3 Compliance Projects in order for Culley Unit 3 to continue operating. Ms. Retherford explained how closure of the Culley West pond will extend the useful life of Culley 3, because closure of the Culley West pond is necessary to provide a suitable location to construct a new pond that can continue to take non-CCR process water discharged from Culley Unit 3 and plant stormwater (i.e. surface water) which flows into the West Pond. Without this new lined process and stormwater pond, continued operation consistent with applicable regulations would be impossible after the Culley East pond commences closure.

No party disputes that construction of the Culley 3 Compliance Projects will extend the useful life of Vectren South's Culley 3 unit or that Culley 3 would be required to retire in the near future if the Culley 3 Compliance Projects are not completed. However, the Industrial Group challenged the need to recover the costs for the Culley 3 projects via a tracking mechanism. We will discuss this issue below.

vii. Ultimate Finding. We find that the Culley 3 Compliance Projects will allow Vectren South to comply directly or indirectly with one or more federally mandated requirements and that public convenience and necessity will be served by the Culley 3 Compliance Projects.

B. Accounting and Ratemaking Issues Associated with Culley Compliance Projects. Ind. Code § 8-1-8.4-7(c) states:

> If the commission approves under subsection (b) a proposed compliance project and the projected federally mandated costs associated with the proposed compliance project, the following apply:

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Based on the evidence presented, we find that Vectren South has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(E).¶

(1) Eighty percent (80%) of the approved federally mandated costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism that allows the timely recovery of the approved federally mandated costs. The Commission shall adjust the energy utility's authorized net operating income to reflect any approved earnings for purposes of IC 8-1-2-42(d)(3)and IC 8-1-2-42(g)(3).

(2) Twenty percent (20%) of the approved federally mandated costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, based on the overall cost of capital most recently approved by the commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the commission.

(3) Actual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent (25%) shall require specific justification by the energy utility and specific approval by the commission before being authorized in the next general rate case filed by the energy utility with the commission.

i. Accounting and Ratemaking Treatment for ECA. Vectren South requests authority to implement a new annual rate adjustment mechanism ("ECA") pursuant to Ind. Code § 8-1-8.4-7 for the timely and periodic recovery of 80% of the federally mandated costs. Vectren South also requests approval of proposed changes to its electric service tariff relating to the proposed ECA mechanism, including the proposed Appendix E. Ind. Code §8-1-8.4-8 provides that an energy utility may, in a timely manner, recover 80% of all federally mandated costs through a periodic rate adjustment mechanism. Ind. Code §§ 8-1-8.4-4 and 8-1-8.4-7 provide that such costs include capital, AFUDC, O&M, depreciation, tax, and financing costs.

a. ***Summary of Evidence.***

Vectren South witness Swiz described how the eligible costs associated with the Culley 3 Compliance Projects will be incorporated into the proposed ECA mechanism. He testified Vectren South will prepare in each annual filing a revenue requirement calculation accumulating all eligible costs incurred through December 31 of the previous calendar year. To provide for timely recovery, Mr. Swiz testified the proposed ECA will project an annualized level of expense related to the approved projects for the twelve-month effective period. Mr. Swiz stated the annual revenue requirements will capture eligible new capital investments (both in service and Construction Work in Progress) related to the Culley 3 Compliance Projects, multiplied by the applicable rate of return, with depreciation, O&M and property tax expenses associated with the projects, and recovery of the regulatory assets recorded through interim deferral of depreciation expense, plan development expense, and PISCC, added to the resulting total. The revenue requirement for those projects will be the basis for the recovery of 80% of the eligible revenue requirement amounts in each annual ECA filing.

Mr. Swiz also described Vectren South's proposal to defer and subsequently recover depreciation expense as well as costs associated with development of the Culley 3 Compliance Projects through the ECA. The cumulative deferred balances of the regulatory assets recorded through interim deferral of such depreciation expenses would be amortized over the remaining life of the assets (20 years) and the amortization amount would be included in the ECA revenue requirements. Mr. Swiz stated the costs of development of the projects would be included for recovery within the ECA, with the balance amortized over a period of three (3) years.

Vectren South proposes the pre-tax return on the new capital investment will be calculated by multiplying the pre-tax rate of return, based on the WACC, by total new capital investment related to the approved projects. Mr. Swiz testified Vectren South proposes to use a WACC in the ECA based upon the most recent approved WACC within Vectren South's TDSIC mechanism under Cause No. 44910, which is based on a return on equity ("ROE") of 10.4% as approved in Cause Nos. 43111 and 43839, Vectren South's two most recent base rate cases. Mr. Swiz stated the equity component of the rate used in the ECA revenue requirement calculation will be grossed up for recovery of income taxes, both state and federal, at then current rates.

Mr. Swiz testified that approved recoveries within each ECA filing will be calculated by taking the billing determinants by month multiplied by the applicable rates and charges for the ECA period. Any under recoveries resulting from instances in which ECA rates and charges are not in place for a full month will be recovered as an under-recovery variance in a subsequent ECA proceeding. Vectren South proposes to allocate ECA costs pursuant to the four-coincident peak allocation percentages for Vectren South utilized in its Cause No. 43406-RCRA15 and 43405 DSMA15 rate mechanisms.

With respect to the treatment of operating income, Mr. Swiz testified Vectren South will adjust its statutory earnings test under Ind. Code § 8-1-2-42(d)(3)to include the incremental earnings from approved ECA filings.

Mr. Swiz testified Vectren South proposes to file its ECA petitions and cases in chief annually, on May 1 of each year, with new ECA rates and charges becoming effective August 1 of each year. Each filing will be based on capital investments and expenses through the twelve months ended December of the prior calendar year. Variances will be reconciled in each ECA filing and recovered over the subsequent twelve month rate effective period. Vectren South seeks approval of its proposed Sheet No. 69, Appendix E, Environmental Cost Adjustment. Additional changes to Vectren South's rate schedules in its tariff are needed to reflect that the ECA will be applied monthly.

Industrial Group witness Mr. Gorman testified that Petitioner has not demonstrated that the combination of its base rate charges and the ECA charges related to the Culley 3 projects will result in total charges to customers that are equal to its cost of service, and are just and reasonable. Gorman Direct at 37. Mr. Gorman testified that known and measurable reductions in Vectren's costs of service may be adequate to offset, in whole or in part, the additional revenue requirement needed to pay for the Culley project costs for two reasons. First, since Vectren's last base rate case in 2010, Vectren has implemented a TDSIC tracker and is proposing to begin tracking the MATS costs discussed above. Vectren's FERC Form 1 submissions indicate that net plant investment has been level since 2010. See Gorman Direct at 38; MPG-2. Second, Vectren's overall rate of return has decreased significantly since the last rate case. Between 2010 and 2017, Vectren's estimate of the weight of cost-free capital to total capital increased from 12.1% to 21.6%. Its embedded debt cost decreased during this time from 6.25% to 4.83%. In addition, Mr. Gorman testified that Vectren's currently authorized ROE from the 2010 rate case is 10.4%, which is significantly higher than authorized returns of electric utilities in general (around 9.6%) and for Indiana utilities (between 9.8-10.0%). Mr. Gorman recommended that the ELG costs associated with the Culley 3 Compliance Projects be recovered within a base rate proceeding and not through the proposed ECA.

Deleted: He cited Vectren South's overall rate of return and stated Vectren South's costs have decline since the last base rate case. He also suggested that Vectren South should be permitted to recover a return on investment of no more than 9.8%.

Mr. Swiz explained on rebuttal that under the statutory test under Ind. Code § 8-1-2-42(d) and -42.3, performed in Vectren South's most recent Fuel Adjustment Clause proceedings as of the time his rebuttal testimony was filed (Cause No. 38708 FAC 120), Vectren South's comprehensive earnings compared to authorized levels, including both changes in expenses and revenues, show that Vectren South is currently under-earning by approximately $6.5 million of net operating income and has been under-earning since February 2017. Mr. Swiz explained that depreciation and operating expense are driving much of these results, and Mr. Gorman does not capture those expenses in his calculation.

Mr. Swiz testified that pursuant to Ind. Code § 8-1-8.4-7, Vectren South seeks ratemaking treatment for 80% of the costs associated with the Culley 3 Compliance Projects through its proposed ECA mechanism. Specifically, Vectren South seeks timely recovery of all federally mandated costs associated with the Culley 3 Compliance Projects, including capital costs, AFUDC, PISCC, O&M, depreciation expense, property tax expense, and other taxes, with 80% recovered through the ECA and the balance deferred for recovery in Vectren South's next rate case.

Deleted: Eligibility for recovery through Ind. Code ch. 8-1-8.4 is not contingent on whether other costs have declined to offset the new federally mandated costs. Once we have made the required findings, 80% of the federally mandated costs "shall be recovered by the energy utility through a periodic retail rate adjustment mechanism." Ind. Code § 8-1-8.4-7(c)(1). In any event, we find that Mr. Swiz has adequately explained why Mr. Gorman's position is incorrect.¶

Vectren South proposes to implement CWIP ratemaking treatment related to the recovery of financing costs incurred during construction of the Culley 3 Compliance Projects. In connection with CWIP ratemaking treatment, Vectren South will remove from the AFUDC-eligible balance the amount of investment included for recovery in the ECA, so that only the amount of the Culley 3 Compliance Projects investment not currently being recovered in the ECA would be eligible for AFUDC.

Mr. Swiz testified that Vectren South proposes to accrue post-in-service carrying charges on all eligible new capital investment from the date it is placed in service until the date it is included in rates. He explained the PISCC balances will be multiplied by the pre-tax rate of return within the ECA revenue requirement, at the WACC rate described herein. Unlike other utilities who have been granted such authority, Vectren South is not seeking to accrue and subsequently recover in the next base rate case PISCC on the 20% deferred balance discussed below.

OUCC witness Aguilar opposed Vectren South's request to recover pond closure costs for the Culley 3 Compliance Projects as part of the ECA because the OUCC's position is that Vectren South is already collecting pond closure costs within its depreciation rates. Ms. Aguilar also testified that neither Duke, IPL, nor NIPSCO are tracking pond closure costs. We have already addressed these positions and rejected them.

Vectren South requested authority to defer (until captured within the ECA mechanism) and recover 80% of the approved federally mandated costs incurred in connection with the Culley 3 Compliance Projects through the approved ECA Mechanism pursuant to Ind. Code § 8-1-8.4-7, including capital, O&M, depreciation, taxes, financing, and carrying costs based on the current overall WACC and AFUDC. Vectren South also requested authority to utilize CWIP ratemaking treatment for the Culley 3 Compliance Projects through the proposed ECA mechanism. Vectren South also requested authority to defer post-in service costs of the Culley 3 Compliance Projects, including carrying costs based on the current overall WACC, depreciation, taxes and operating and maintenance expenses on an interim basis until such costs are recognized for ratemaking purposes through Vectren South's ECA mechanism or otherwise included for recovery in Vectren South's base rates in its next general rate case. Vectren South also requested authority to defer and recover through the ECA mechanism 80% of its federally mandated costs, including but not limited to federally mandated costs incurred prior to and after approval of a final order in this proceeding to the extent that such costs are reasonable and consistent with the scope of the Culley 3 Compliance Projects described in Vectren South's evidence. Vectren South also requested approval of its proposed cost allocation factors.

b. *Commission Findings.*

As Mr. Gorman explained, the overall reduction in Vectren's costs obviates any need to recover the Culley 3 work via the ECA tracker. The declines in Vectren's overall rate of return—even using Vectren's proposed return on equity of 10.4%—have resulted in a reduction of the revenue requirement of $12.6 million. Factoring in a reduction in return on equity to 9.8%, the reduction in revenue requirement would be $17.1 million. Both figures are lower than the $11.3 revenue requirement for the Culley 3 project. Gorman Direct at 38-39; Attachment MPG-3. Although the Company claims financial need to track the Culley-3 costs and that the statutory earning test shows it is under-earning, (Swiz Rebuttal at 11-12), those assertions fail to account for the fact that the utility has not brought a rate case since 2010.

Based on the evidence presented, we find that Petitioner has failed to demonstrate need to track its Culley 3 costs, and has failed to establish the overall reasonableness of the resulting rates. As we have found previously, we may consider the need for a tracking mechanism under Indiana Code Chapter 8-1-8.4 in determining whether to approve a CPCN and associated ratemaking treatment. *Indianapolis Power & Light Co.*, Cause No. 44339 (IURC 5/14/2014), p. 38. Approval of a CPCN should not be given simply because it was requested, if it is not necessary for the utility. *Id.* at 39. Moreover, nothing in Indiana Code Chapter 8-1-8.4 alters the requirement of I.C. § 8-1-2-4 that any charge made by a public utility must be reasonable and just, and that every unjust and unreasonable charge is prohibited and declared unlawful. Accordingly, we deny Petitioner's request to track the Culley-Three projects.

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Deleted: the proposed ECA mechanism should allow for the timely and periodic recovery of 80% of Vectren South's approved federally mandated costs. We further find that Vectren South's request for approval to adjust its authorized net operating income to reflect an approved earnings associated with the Culley 3 Compliance Project for purposes of Ind. Code §§ 8-1-2-42(d)(3) and 8-1-2-42(g)(3) is consistent with Ind. Code § 8-1-8.4-7(c)(1).¶

Moved up [1]: Vectren South is authorized to defer (until captured within the ECA mechanism) and recover 80% of the approved federally mandated costs incurred in connection with the Culley 3 Compliance Projects through the approved ECA Mechanism pursuant to Ind. Code § 8-1-8.4-7, including capital, O&M, depreciation, taxes, financing, and carrying costs based on the current overall WACC and AFUDC. Vectren South is authorized to utilize CWIP ratemaking treatment for the Culley 3 Compliance Projects through the proposed ECA mechanism. Vectren South is authorized to defer post-in service costs of the Culley 3 Compliance Projects, including carrying costs based on the current overall WACC, depreciation, taxes and operating and maintenance expenses on an interim basis until such costs are recognized for ratemaking purposes through Vectren South's ECA mechanism or otherwise included for recovery in Vectren South's base rates in its next general rate case. Vectren South is authorized to defer and recover through the ECA mechanism 80% of its federally mandated costs, including but not limited to federally mandated costs incurred prior to and after approval of a final order in this proceeding to the extent that such costs are reasonable and consistent with the scope of the Culley 3 Compliance Projects described in Vectren South's evidence. Vectren South's proposed cost allocation factors are also approved.

Deleted: ii. Accounting and Ratemaking Treatment for Deferred Costs. Indiana Code § 8-1-8.4-8 provides that 20% of the approved federally mandated costs, including depreciation, AFUDC, and PISCC, based on the overall cost of capital most recently approved by the Commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the Commission. Vectren South proposes to defer as a regulatory asset 20% of all federally mandated costs incurred in connection with these projects. ¶
Based on the evidence presented, the Commission finds Vectren South is authorized to defer 20% of the federally mandated costs incurred in connection with the Culley 3 Compliance Projects, and Vectren South may recover the deferred costs in its next general rate case as allowed by Ind. Code § 8-1-8.4-7(c)(2

ii. Depreciation Treatment. Vectren South proposes to utilize a depreciation rate of five percent (5%), representing a twenty-year (20-year) life on these investments. Mr. Swiz testified the proposed depreciation rate for the investments aligns with the estimated remaining life of Culley Unit 3.

No party opposed Vectren South's proposed depreciation rate for the investments required for the Culley 3 Compliance Projects.

Based on the evidence presented, we find that Vectren South's proposal to depreciate the individual projects included in the Culley 3 Compliance Projects based on a 5% depreciation rate is reasonable and is approved.

10. Recovery of Prior Pollution Control Investments ("MATS Projects.").

Our January 28, 2015 and June 22, 2016 Orders in Cause No. 44446 (the "44446 Orders") (1) granted Vectren South a CPCN for Brown Unit 1 and 2, Culley Unit 3 and Warrick Unit 3 clean coal technology projects and (2) authorized the Company to recover federally mandated costs associated with federally mandated requirements at Brown Units 1 and 2 (collectively the "MATS Projects"). Rather than recovering the costs of the MATS Projects through a tracking mechanism as authorized by Ind. Code § 8-1-8.4-7, Vectren South sought, and we granted, authority to defer these costs for recovery in a future proceeding. The Company now seeks to commence recovery of the MATS Projects' costs through the ECA pursuant to I.C. 8-1-8.4-7.

A. Overview Vectren's requested ratemaking.

i. Summary of the Evidence.

Vectren South witness Swiz described the proposed recovery through the ECA in more detail. He indicated that Vectren South proposes recovery of the MATS Projects to begin on January 1, 2019 with the approval of ECA rates and charges recovering the specified revenue requirement. In accordance with applicable statutory requirements, the Company proposes to recover the 80% of eligible revenue requirements amounts for post-in-service carrying costs, incremental depreciation and property taxes and financing costs that the Company incurred to construct the MATS Projects and deferral of the remaining 20% of these costs for subsequent recovery in a base rate case. The Company will prepare an annual revenue requirement as part of the ECA to capture eligible capital investments in plant related to the MATS Projects, multiplied by the applicable rate of return, with depreciation, O&M, and property tax expenses associated with the MATS Projects added to the resulting total. To provide for timely recovery, Vectren South's proposed ECA will project an annualized level of expense related to these approved projects for the twelve-month effective period.

Vectren proposes that depreciation associated with the MATS Projects be based on the currently approved depreciation rates applicable to the assets, as approved in Vectren South's last electric base rate case (Cause No. 43839). The pre-tax return on the new capital investment will be calculated by multiplying the pre-tax rate of return, based on the WACC, by total new capital investment related to the approved projects. The Company proposes to use a WACC in the ECA based upon the most recent approved WACC within the Company's TDSIC mechanism, Cause No. 44910. This WACC, approved by the Commission, represents an updated actual capital

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structure as of the cut-off date of each TDSIC filing, and includes the typical items captured in the Company's base rate case capital structure. Vectren proposed that this rate be used in the ECA revenue requirement calculation, and the equity component will be grossed up for recovery of income taxes, both state and federal, at then current rates. Vectren proposed that O&M expense included for recovery in the ECA reflect an annualized level of expense related to the MATS Projects. Vectren explained that this O&M expense represents incremental chemical costs and other expenses associated only with the MATS Projects.

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Industrial Group witness Mr. Gorman made two recommendations regarding ratemaking issues with respect to the MATS tracker that Vectren accepted in rebuttal. First, Vectren agreed that the deferral of MATS costs should be adjusted to reflect the current federal income tax rate. Gorman Direct at 34-35; Swiz Rebuttal at 9. Second, Vectren agreed to Mr. Gorman's recommendation to prevent double recovery by rolling forward the net book value of the MATS projects through 2018. Gorman Direct at 35; Swiz Rebuttal at 10.[12]

i. Commission Findings.

No party objected to the Company's proposal to commence recovery of MATS Projects' costs, currently being deferred, through the ECA. The Industrial Group, however, challenged the applicable ROE. We previously found the MATS Projects costs qualify as federally mandated costs in the 44446 Orders. While Vectren South proposed, and we approved of, deferral of these costs in lieu of the recovery through a periodic retail rate adjustment mechanism, Vectren South now seeks to recover the costs in accordance with Ind. Code § 8-1-8.4-7(c). We find that Vectren South shall be authorized to commence recovery of these MATS Projects costs pursuant to I.C. 8-1-8.4-7 through the ECA in accordance with the procedures outlined in Mr. Swiz's testimony, except as modified to apply a 9.8% ROE as discussed below.

B. ROE for MATS Projects in the ECA tracker.

i. Summary of the Evidence.

Vectren proposes to apply the return on equity ("ROE") authorized in its 2010 rate case (Cause 43839) of 10.4% to the ECA tracker. Mr. Gorman testified that this return substantially exceeds the authorized returns on equity for electric utilities in the current market environment, and does not reflect substantial declines in capital market costs since Vectren's last rate case. Gorman Direct at 31-32. He testified that a return no higher than 9.8% is appropriate because it reflects a fair consideration of a return on equity based on current capital market costs. *Id.* at 33. In support of his 9.8% figure, Mr. Gorman cited to three recent settled rate cases of Indiana investor-owned utilities. Mr. Gorman also demonstrated that authorized returns on equity have declined nationwide since 2010, down to approximately 9.6%. In addition, Mr. Gorman also testified that utility bond costs have declined since 2010. *Id.* at 32.

In rebuttal, Mr. Swiz took issue with Mr. Gorman's recommendations with respect to ROE, though Mr. Swiz acknowledged his own lack of expertise on the drivers of ROE. Swiz Rebuttal

[12] Petitioner also voluntarily removed property tax expense for MATS projects from the ECA tracker consistent with Vectren's July 18, 2018 Corrected Testimony and Exhibits. Gorman Direct at 36; Swiz Direct at 10.

at 8. Mr. Swiz challenged Mr. Gorman's discussion of the ROEs in the recent settled rate cases of Indiana investor-owned utilities,[13] contending that the ROEs applied to other Indiana utilities is irrelevant. *Id.* at 8-9.

ii. Commission Discussion and Findings.

Mr. Gorman testified that the 10.4% ROE approved in Petitioner's 2010 rate case should not be applied to Petitioner's ECA tracker because it is excessive in light of current rates. Mr. Gorman supported his claim by citing to three recent Indiana investor owned utility rate cases, all of which demonstrated a downward trend for ROEs to less than 10.0. We disagree with Mr. Swiz' contention that the ROE approved for other Indiana investor owned utilities in Indiana is irrelevant to the question of the appropriate return for Vectren. We have specifically found the prevailing ROEs of other Indiana investor owned utilities to be relevant to the determination of the ROE of the Indiana investor owned utility at issue. *See, e.g., Indianapolis Power & Light Co.*, Cause No. 44339 (IURC 5/14/2014), p. 34. Moreover, ROEs from Indiana utilities were not the only compelling evidence presented. Mr. Gorman also demonstrated that authorized ROE's have declined nationwide since 2010, down to approximately 9.6%, and that utility bond costs have declined as well. Petitioner did not challenge the accuracy or relevance of either of these points.

In addition, we note that our previous approval of the use of a 10.4% ROE does not prevent us from making another decision in a later case involving distinct costs. *See, e.g., Indianapolis Power & Light Co.*, Cause No. 44339 (IURC 5/14/2014), p. 33. Indiana Code Chapter 8-1-8.4 does not specify the cost of capital that must be used for purposes of costs recovered via the tracker, and I.C. § 8-1-2-4 imposes an overall requirement that rates be just and reasonable. Moreover, if the utility seeks to recover the 20% of deferred costs in a subsequent rate case, the statute requires that carrying costs be calculated to reflect any changes to the overall cost of capital made in this case (or any subsequent changes made prior to the next rate case). *See* I.C. § 8-1-8.4-7(c)(2) (requiring that the 20% of post-in-service capital costs be "based on the overall cost of capital most recently approved by the commission.")

The Industrial Group has supported its recommended adjustments regarding the appropriate ROE to be applied to the ECA tracker for MATS projects with qualified expert testimony, and we find its position on this point persuasive. We also note that Petitioner has changed its request in this case from its original proposal in Cause 44446 to defer the MATS Projects costs in lieu of recovery through a tracker. Given this change in position (and deviation from the proposal we had originally approved), and the unreasonableness of application of a 10.4% ROE under current market conditions, we find it appropriate to evaluate the ROE to be applied to this tracker. We find that a 9.8% ROE shall be applied to Petitioner's MATS projects in the ECA tracker. Petitioner shall revise its schedules accordingly and submit a compliance filing to the Commission implementing this adjustment.

6. **Confidentiality**. Vectren South filed motions for protection and nondisclosure of confidential and proprietary information on March 20, 2018, August 21, 2018, and September 10, 2018, respectively. In its motions, Vectren South states certain information

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[13] The question posed to Mr. Swiz erroneously indicates that Mr. Gorman discussed only two rate cases, though he discussed three (Indiana Michigan Power, Indianapolis Power and Light, and NIPSCO Gas). *Compare* Swiz Rebuttal at 8 *with* Gorman Direct at 34.

redacted in the evidence is confidential, proprietary, competitively sensitive, and/or trade secrets. Docket entries were issued on March 29, August 27, and October 4, 2018 finding such information to be preliminarily confidential and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. The confidential information was subsequently submitted under seal. The Commission finds the information for which Vectren South seeks confidential treatment is confidential pursuant to Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3, is exempt from public access and disclosure by Indiana law, and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

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

1. Vectren South shall be and hereby is issued a certificate of public convenience and necessity under Ind. Code ch. 8-1- 8.5 to construct an 850 MW duct-fired F-class 2x1 CCGT to be located at Vectren South's existing A.B. Brown Station. The certificate is subject to the qualifications set forth herein. This Order constitutes the Certificate. Upon implementation of rates following the first general rate case including the CCGT in rate base, Vectren South shall pass through 100% of off system sales revenues received to customers.

2. Vectren South's estimated total cost of the CCGT in the amount of $781 million (not including the costs of the gas lateral) is approved as set forth herein.

3. Vectren South's request for ongoing review of the CCGT is approved as set forth and modified herein. Vectren South shall file the ongoing reports as set forth in Paragraph 7 for the purpose of ongoing review in accordance with Ind. Code § 8-1-8.5-6.

4. Vectren South is issued a certificate of public convenience and necessity for the Culley 3 Compliance Projects pursuant to Ind. Code ch. 8-1-8.4. This Order constitutes the Certificate.

5. The CCR Rule and the ELG Rule constitute federally mandated requirements as defined by Ind. Code § 8-1-8.4-5.

6. Vectren South's proposed Environmental Cost Adjustment ("ECA") is approved in part and denied in part. Petitioner shall revise its proposed Sheet No. 69, Appendix E of its tariff and submit a compliance filing consistent with this Order within 30 days.

7. Vectren South's request to defer (until reflected in the ECA) and recover 80% of the approved federally mandated costs incurred in connection with the Culley 3 Compliance Projects through the mechanism approved herein pursuant to Ind. Code § 8-1-8.4-7 including capital, O&M, depreciation, taxes, financing and carrying costs is denied.

8. Vectren South's request to utilize construction work in progress ratemaking treatment for the Culley 3 Compliance Projects through its ECA Rider is denied.

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8. Vectren South's cost estimates for the Culley 3 Compliance Projects set forth above are approved.

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9. Vectren South's request to accrue AFUDC relating to the Culley 3 Compliance Projects until such time as the projects included in the Culley 3 Compliance Projects are placed into service or receive ratemaking treatment is denied.

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10. Vectren South's request to accrue post-in service carrying charges related to the Culley 3 Compliance Projects, including carrying costs based on its WACC, and to defer depreciation, taxes and O&M expenses on an interim basis until such costs are recognized for ratemaking purposes through Vectren South's ECA or otherwise included for recovery in Vectren South's base rates in its next general rate case, is denied.

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Deleted: 13. Vectren South is authorized to adjust its authorized net operating income to reflect any approved earnings associated with the Culley 3 Compliance Projects for purposes of Ind. Code § 8-1-2-42(d)(3) as allowed under Ind. Code § 8-1-8.4-7(c)(1).

11. Vectren South's request to defer 20% of the federally mandated costs incurred in connection with the Culley 3 Compliance Projects for recovery in its next general rate case is denied.

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12. Vectren South's request to defer depreciation and to accrue post-in service carrying charges related to the CCGT, including carrying costs as modified herein, until such costs are recognized for ratemaking purposes through Vectren South's base rates in its next general rate case, is denied.

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13. Vectren South is authorized to depreciate the individual projects included in the Culley 3 Compliance Projects according to depreciation rates set forth above.

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14. Vectren South is authorized to record all post-in-service carrying charges and deferred depreciation for the MATS projects as modified and authorized herein as regulatory assets in Account 182.3 Other Regulatory Assets.

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15. Vectren South's proposed recovery of federally mandated costs approved in connection with Cause No. 44446 through the ECA shall be and hereby is approved as described in this Order.

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16. The Confidential Information submitted under seal in this Cause pursuant to Vectren South's requests for confidential treatment is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall continue to be held as confidential and exempt from public access and disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4.

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

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<u>HUSTON, FREEMAN, KREVDA, OBER, AND ZIEGNER CONCUR</u>:

APPROVED:

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

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Mary M. Becerra
Secretary to the Commission

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