SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

D/B/A

VECTREN ENERGY DELIVERY OF INDIANA, INC.

CAUSE NO. 45052

PUBLIC REBUTTAL TESTIMONY

OF

WAYNE D. GAMES

VICE PRESIDENT OF POWER SUPPLY

SPONSORING PETITIONER'S EXHIBIT NO. 4-R,
ATTACHMENTS WDG-1R THROUGH WDG-4R

REBUTTAL TESTIMONY

OF

WAYNE D. GAMES

VICE PRESIDENT OF POWER SUPPLY

Q. Please state your name and business address.

A. My name is Wayne D. Games, and my business address is One Vectren Square, Evansville, Indiana 47708.

Q. Did you provide Direct Testimony on behalf of Vectren South in this Cause?

A. Yes.

Q. Are you sponsoring any exhibits in support of your testimony?

A. Yes. I am sponsoring the following exhibits:

- Petitioner's Exhibit No. 4-R, Attachment WDG-1R, a list of Brown Corrosion Projects from 2008-2018;
- Petitioner's Exhibit No. 4-R, Attachment WDG-2R, Indianapolis Power & Light's ("IPL") Harding Street Station Energy Information Administration ("EIA") Data.
- Petitioner's Exhibit No. 4-R, Attachment WDG-3R, Timeline For CCGT Construction
- Petitioner's Exhibit No. 4-R, Attachment WDG-4R, Capacity of Unfired CCGT

Q. Were the exhibits identified above prepared or assembled by you or under your direction or supervision?

A. Yes.

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

A. Various witnesses from the Indiana Office of Utility Consumer Counselor ("OUCC"), Alliance Coal, LLC ("Alliance Coal"), the Indiana Coal Council ("ICC") and the Citizens Action Coalition/Valley Watch/Sierra Club ("Joint Intervenors") allege that customers face fewer risks if Southern Indiana Gas and Electric Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South" or the "Company") retains its aging, uncompetitive, existing generation fleet for some period of time beyond 2024 rather than replacing several of these units with a highly efficient combined cycle gas plant ("CCGT"). While several other Vectren South witnesses will explain why these parties have reached the wrong conclusion, my testimony will focus on the significant risks presented from an operational standpoint by trying to keep these units running beyond 2024. I will explain the competitive challenges faced by our units in the Midcontinent Independent System Operator ("MISO") energy market, the risks with continued reliance on these units, and explain why the efficient CCGT the Company is seeking approval to construct presents lower risks. I also:

- Discuss issues with converting the Brown units from coal to gas fired.
- Discuss the project timeline and risks associated with delaying until the next IRP.
- Address why the preferred IRP plan offers diversity and why it makes sense to duct fire the proposed CCGT.
- Show the reduction in annual wholesale power margin due to Vectren South coal units not being competitive.
- Respond to criticisms from the OUCC that Vectren South's cost estimate is not reliable.
- Discuss recommendations made by the Industrial Group relating to contracting for construction of a CCGT.
- Explain that Vectren South did consider alternative scrubber technology at A.B. Brown.

I. Risk Is Not Mitigated By Delaying The Decision

Q. Can you summarize the position of the other parties regarding Vectren South's proposal?

A. Except for the Industrial Group, who represents specific Indiana customers, the other parties all contend that Vectren South should minimize risk by sticking with its existing resources in one form or another. ICC, Sunrise Coal and Alliance Coal, not surprisingly, want to keep the A.B. Brown facility ("Brown") burning coal, for as long as reasonably possible. This protects their own economic interests in ensuring continued demand for their product. The OUCC urges Vectren South to convert one or both of the Brown baseload units to utilize natural gas, continue operating the remainder of the generation fleet and wait for more certainty. The Joint Intervenors criticize Vectren South's modeling assumptions and make no specific recommendation beyond denial of our requested CPCNs.

Q. Is there a common basis these parties rely on to justify continuing with Vectren South's existing generation resources?

A. Yes. The parties all allege that retiring Vectren South's smaller coal units and building a larger gas plant is risky for customers. Other Vectren South witnesses discuss the modeling Vectren South has done and the assessment of risk involved in that modeling. In my role as Vice President of Power Generating, I am very familiar with the existing Company generation facilities the parties propose to keep running. There are numerous risks with continuing to rely on these units for the foreseeable future that the other parties ignore. I will discuss these risks and explain why Vectren South's proposed CCGT better mitigates customers' risk.

A. Risks From Continuing Vectren South's Heavy Reliance on Coal-Fired Generation

Q. What are the primary risks associated with continuing to operate a coal heavy fleet?

A. A coal heavy fleet, especially one dominated by small, aging plants, is exposed to risks from future environmental regulations, poor MISO market performance and reliability.

Q. Please discuss the risks created by environmental regulations applicable to Vectren South's existing generation fleet.

A. Coal plants face significant risks of rising costs and reduced efficiency from future environmental regulations. Vectren South has already made significant environmental control investments and the variable costs to operate this equipment places further pressure on the economics of the Company's generating facilities. For example, Vectren South spends in excess of [redacted] (an approximate [redacted] premium per MWHr generated) for the chemicals to remove sulfur dioxide (SO_2), nitrogen oxide (NO_x), sulfuric acid (H_2SO_4), particulate and mercury at Brown. The injection of sodium to control for H_2SO_4 at Brown has caused plugged nozzles and sodium build up in duct work necessitating outages to correct. In 2018, the Company must purchase seasonal NO_x allowances for Brown at a cost of $150-$350 per allowance. Brown's water treatment costs associated with its National Pollution Discharge Eliminations System ("NPDES") permit have increased to sample for several constituents and treat for mercury, oil and grease, suspended solids, total residual chlorine and copper and iron. Starting in April of 2020, Brown will incur more cost associated with treating water discharge for selenium, chlorides and copper.

As Company witness Retherford discusses, there continue to be risks of further environmental regulation as administrations change. This includes carbon regulation, stricter NPDES limits and the Environmental Protection Agency ("EPA") ratcheting down on SO_2 and NO_x allowance values and/or potentially changing these and other emission limits associated with coal fired units. The newly announced replacement to the Clean

Power Plan ("CPP") appears to require incremental efficiency improvements at coal fired power plants, necessitating additional capital investments. Vectren South improved the efficiency of Brown by installing dense packs in 2012 and 2013 at an incremental capital cost of $28.6 million. There continues to be a push by some to regulate carbon through a tax or other approach. This creates the risk of additional incremental costs for coal plants because of their significant carbon emissions.

Q. Please discuss the risks for coal-fired generation plants created by the MISO market, intermittent renewable resources, and low natural gas costs.

The MISO energy market dispatches the lowest cost generation required to maintain system reliability, giving MISO members the lowest cost energy available. Highly efficient CCGT natural gas plants and renewable resources are lower cost than the Company's small coal plants, contributing to falling capacity factors for the smallest least efficient coal units. These units must drop to minimum output or cycle off during the off-peak hours because they are higher cost than other resources, driving even higher production costs. These factors have a direct impact on customers. On a daily basis, Vectren South offers all of its units into the MISO market and purchases all of its customers' needs for electricity from the MISO market. On days when the Company's units are dispatched by MISO, the cost of the energy Vectren South purchases to serve its customers can be offset in part by the revenues paid by MISO for the energy sold into the MISO market. The higher costs associated with the low efficiency of Vectren South's coal units greatly reduces the opportunity for additional revenues used to reduce customer daily energy costs. Vectren South's units are particularly vulnerable because they are the smallest and some of the lowest efficiency (highest heat rate) units in the State. **Figure 1** shows the nameplate capacity of Vectren South's coal units compared to other Indiana Investor Owned Utilities ("IOU's") coal units while **Figure 2** shows the

efficiency or heat rate comparison of Vectren South's coal fleet compared to other Indiana IOU coal units. These Figures show only units anticipated to still be in operation in 2023. A lower heat rate indicates higher efficiency.

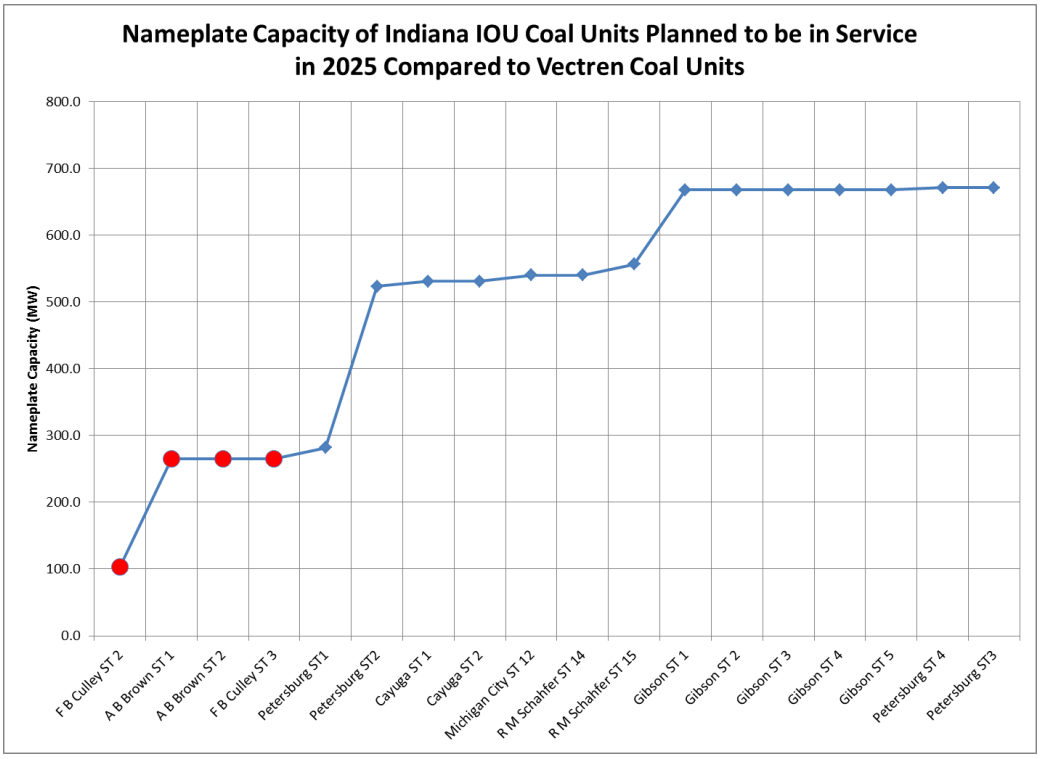


Figure 1

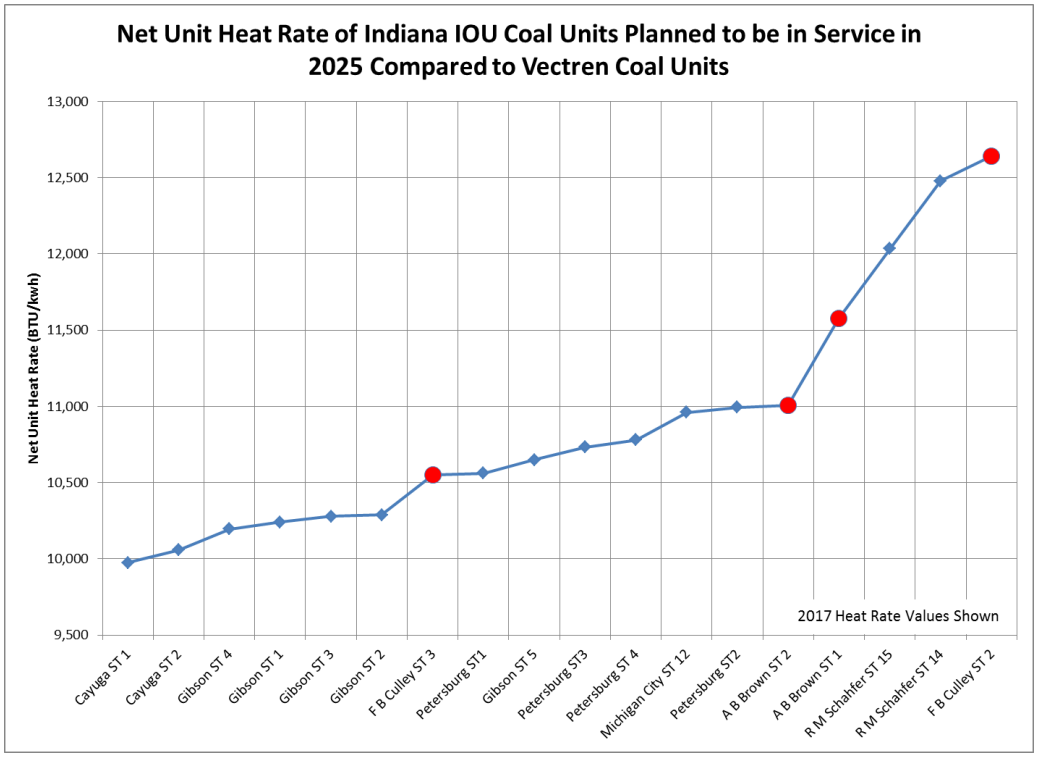


Figure 2

As shown by these Figures, maintaining Culley Units 2&3 and Brown Units 1&2 leaves Vectren South with the four smallest IOU coal units within the State. Except for Culley Unit 3, continuing to rely on these units would leave Vectren South's customers with among the most inefficient coal units within the State. Note that in the interest of maintaining diversity, Vectren South's preferred plan maintains Culley Unit 3 due to it being the largest most efficient coal unit in the current fleet.

Q. Please explain your concerns with the coal units being operated in a manner they were not designed for.

A. Vectren South's coal units were designed as base-load units, meaning that they were designed to continually run at relatively stable levels of output to serve the base needs of our customers. At the time they were constructed, the Company's coal units were very low cost and provided the most cost effective way to meet the demands of customers.

The advancement of technology and the dramatic reduction in the cost and abundance of natural gas have changed the dynamics for coal-fired units. The MISO "Day-Ahead" market dispatches generators that have been offered into the market (starting with the lowest cost source/unit) against hourly forecasted demand. The hourly market energy price is established by the last unit required to meet the demand. Renewables are typically dispatched first because of their low variable operation and maintenance ("O&M") costs and tax incentives that encourage renewable resources to be dispatched whenever they are available. This leaves other forms of generation to fill the gap between what intermittent renewable resources can produce and the changing requirements of retail customers on a real time basis. This gap which can fluctuate rapidly and widely is filled in the MISO "Real-Time" energy market by sources that can adjust (ramp) output quickly.

Due to the production cost (low efficiency) of Vectren South's coal units they are called upon to cycle off/on and ramp up/down more often than more efficient lower cost generation sources including larger super critical coal units. Cycling particularly impacts the Company's generating resources. This has the largest impact on units like Culley Unit 2 and Brown Units 1&2 as they are the smallest and more expensive coal units in the MISO stack. My Direct Testimony referenced a June 3, 2015 U.S. Department of Energy ("DOE") report on coal-fired generation titled "Impact of Load Following on the Economics of Existing Coal Plant Operations". The report recognized that "generally an increase in frequent ramping and/or shutdowns decreases the component life through damage caused by creep, fatigue, thermal shock, acid induced corrosion, erosion, and other stresses".[1] I discussed specific issues outlined in the report and an example of

[1] Creep damage occurs in metals and alloys after prolonged exposure to stress at elevated temperatures.

Solid Particle Erosion ("SPE") that occurred on Brown Unit 1 that caused a 3 month outage and $3.8M repair during the summer of 2016. Since submitting my original testimony other studies have been completed addressing the ramping and cycling issues on coal units designed for baseload operation and we've actually discovered more issues at the Brown plant due to increased cycling over the past 9 years. These include issues that will require more frequent inspections and extensive repairs or future replacement of costly high energy steam piping to ensure reliability of the plant as well as the safety of employees.

Q. How does this create additional risk for Vectren South customers?

A. There is expected to be a significant increase in the Equivalent Forced Outage Rate ("EFOR") and reduction in reliability over time. Vectren South's own experience demonstrates the risk that incremental capital, reduced plant life and increasing outages may result from trying to operate the Company's coal units in a fashion they were not designed for over an extended time period.

Q. Would efforts from the Federal government to monetize coal's resiliency attributes change Vectren South's concerns with continued reliance on its coal units?

A. Not as it is currently being proposed. ICC witness McConnell is referring to a draft memo of the Department of Energy ("DOE") that discussed the possible subsidization of certain coal and nuclear facilities for a two year period. The memo provided no detail regarding how such subsidization would work, the nature of the monetary benefits, and the identification of units selected to benefit from payments. Regardless of such speculation, Vectren South's plan calls for its coal plants to operate through 2023, well beyond this two year period. The Company's operating region is surrounded by large coal units such as Rockport, Gibson and Petersburg that are not currently scheduled to

be retired that would appear to fit more within the DOE's view of resiliency than Vectren South's small coal units.

Q. Do others recognize the same concerns you are raising with continued reliance on coal fired generation?

A. Yes. Just this week a draft report by the National Coal Council ("NCC") entitled "Power Reset: Optimizing the Existing U.S. Coal Fleet to Ensure a Reliable and Resilient Power Grid" became public. ICC witnesses Medine and McConnell, Alliance Coal witness Nasi, and Sunrise Coal witness Dombrowski are all listed authors or committee members. The NCC Report discusses how renewable energy resources impact coal units, and identifies concerns with cycling of coal units, lower revenues for coal units, lower efficiency, and reduced plant life attributable to the same factors I identify for the Company's units. The NCC Report admits that the wear and tear experienced by coal units has led to a point where the reliability of such plants "could be significantly less" and that such cycling conditions result in "increased capital expenditures, increased O&M costs, increased outages and higher fuel consumption."

Q. OUCC witness Alvarez contends that Vectren South's coal units performed at par in some years, and even better in other years, than the entire coal fleet of the country. (Public's Exhibit No. 2, pp. 16-17). Does this history of availability support the proposal to just keep running these plants well beyond 2023?

A. No. While I am pleased the OUCC agrees that Vectren South has done such an effective job operating plants, the more pertinent economic question is how well coal-fired generation is performing in the energy markets. The retirement of coal-fired generation facilities is being announced throughout the country because their high-heat rates and limited ability to ramp is rendering them less economic, especially when

competing with highly efficient gas plants using low cost gas. **Table 1** shows that Brown Units 1&2 and Culley Unit 2 capacity factors have dropped significantly from 2000-2008 to 2009-2017. **Figure 4** shows the Company's annual Wholesale Power Market ("WPM") margin since 2000, establishing that the Company's units are generating wholesale power sales much less frequently since gas prices began dropping in recent years.

	2000-2008	2009-2017
A.B. Brown 1	72%	52%
A.B. Brown 2	76%	55%
F.B. Culley 2	69%	23%

Table 1

WPM ANNUAL MARGIN - 2000 to 2017

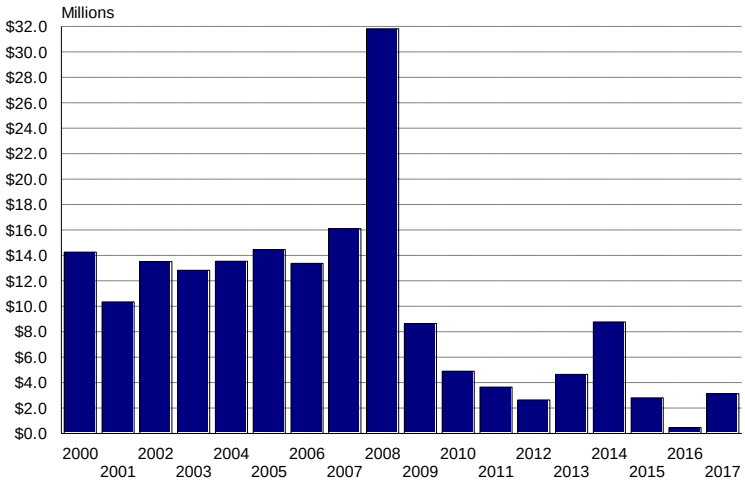


Figure 4

These factors are driving coal plant retirements throughout the country. Data compiled by SNL (S&P Global) shows that 458 coal units constituting over 52 gigawatts ("GWs") of capacity have been retired nationwide since 2012 with 97 of those located in the MISO footprint. Another 85 unit retirements making up another 16 GWs have already been approved for retirement in the U.S. with many others announced but not yet approved. Maintaining a high reliance on aging, small inefficient coal units that require environmental investments and are not designed to provide the flexibility needed to

operate in the MISO market is not a good decision for Vectren South customers. Continuing to rely on coal units to provide 95% of our energy would make the Company an extreme outlier when compared to other US investor owned utilities.

Q. OUCC witness Alvarez contends that replacing the Company's existing smaller units with a single CCGT exposes customers to the risk of reliance on a single unit that could have an outage. (Public's Exhibit No. 2, pp. 11 and 16). Do you agree that this represents greater risk compared to operating the existing coal fleet?

A. No. First, having a new unit designed to effectively ramp production provides greater reliability than operating coal units that simply were never intended to operate in response to dynamic MISO price signals. The risk of older coal units being off line due to either economics or equipment failure is the greater risk. Second, if the CCGT experiences an outage, in the short-term the MISO market can provide energy for customers. Buying energy when needed in the short-term does expose customers to price risk, but that is different than basing a long term resource plan (and meeting MISO Planning Reserve Margin ("PRM") requirements) on the availability and price of market capacity.

B. Specific Risks from Reliance on Brown Units 1 and 2

Q. ICC witness Hayet proposes to continue operating Brown until 2023 (for Unit 1) and 2030 (for Unit 2), ICC witness Medine advocates operating them for another ten years while OUCC witnesses urge converting the units to burn natural gas and continuing their operation indefinitely. What is Vectren South's experience with Brown?

A. Although the Brown units are the newest coal units within Vectren South's fleet (they will be 44 and 37 years of age in 2023), only Culley Unit 2 is more expensive to operate and maintain. Brown requires the largest capital investment among Vectren South's fleet to continue reliable operation beyond 2023. Apart from Coal Combustion Residual ("CCR") regulation compliance costs, a key challenge for these units is their dual-alkali scrubbers. Dual-alkali scrubbers require expensive chemicals to lower emissions and create a highly corrosive environment that impacts the scrubbers and other plant equipment. The industry has abandoned the dual-alkali scrubber as a result of these challenges and the Brown scrubbers are the only dual-alkali scrubbers still operated by a utility in the United States.

The corrosive environment created by the dual-alkali scrubbers causes regular damage to the infrastructure necessitating capital investment to repair the damage so the plants can continue to operate. As shown in Petitioner's Exhibit No. 4-R, Attachment WDG-1R, over $32M (an average of over $2.9M annually) has been invested to address Brown's corrosion issues to keep the facility reliable and safe for employees. Even if the scrubbers were replaced, remaining equipment impacted by the scrubbers' corrosive chemicals would require repairs. In 2005, a bridge spanning a Brown Unit 1 storage tank collapsed due to corrosion, shutting the unit down for an extended period of time to make repairs.[2] In 2017, over $1M was spent to rebuild a support structure holding ductwork that carries flue gas between the absorber tower and the chimney. Vectren South developed estimated capital and O&M projections for investments to keep Brown running for purposes of its integrated resource plan ("IRP") modeling, but it is very

[2] A picture of this bridge is labeled as photo 27 in Petitioner's Exhibit No. 4, Attachment WDG-1.

difficult to accurately project the capital and other expenses necessary to keep a plant operating with two scrubbers that are causing so many issues.

The scrubbers are already beyond their 30-year design life. Burns & McDonnell's ("B&McD") assessment of these scrubbers, attached to my direct testimony as Petitioner's Exhibit 4, Attachment WDG-1, concluded that "it would be prudent for Vectren South to retire and/or replace the Brown scrubbers at a total life of 40-45 years maximum, which implies the scrubbers should be retired and/or replaced sometime over the next 5-10 years". ICC witness Hayet accepts this for purposes of his modeling although Ms. Medine appears to advocate for stretching operation even beyond this recommended period. Vectren South is proposing to retire Brown Unit 1 when its scrubber is 44 years old and Brown Unit 2 when its scrubber is 37 years old, well beyond the 30-year design life. From a safety and reliability perspective, I do not agree that it is prudent to push the life of these scrubbers beyond 2023.

Q. OUCC witness Aguilar dismisses Vectren South's concerns with loading fly ash onto barges at Brown by indicating that the Company "may have to investigate the cost to temporarily store fly ash [at Brown] for occasions when barges cannot be loaded." (Public's Exhibit No. 1, pp. 21-22). What would it cost to address this concern?

A. Options and capital cost to modify Brown dry fly ash system were evaluated by Black & Veatch ("B&V") who estimated the price of viable alternatives would be around [redacted] This further demonstrates the costs of trying to keep Brown operating with coal.

Q. Are there other risks with continuing to rely on the Brown units?

A. Yes. Since 2008, the Brown plants and Culley Unit 2 cycle more than any other Vectren South plant because they are not competitive in the MISO energy market. I have already

discussed the additional wear and tear this creates for coal-fired units. Several specific issues have been identified at Brown as a result of cycling. Recent assessments of High Energy Piping which transports high pressure steam at Brown show signs of creep damage and other fatigue that will rapidly worsen due to cycling and will require replacement if operated beyond 2023. The Brown Unit 1's super-heater outlet header will need to be replaced due to thermal fatigue and scale build-up. Other welds at Brown show signs of creep damage while others have been determined to be at high risk for creep damage. Creep damage places pipe and welds in a condition that will make them more susceptible to the impacts of cycling. I expect more of these issues as routine inspections are completed over time.

Q. What risk does continuing to rely on Brown create for customers?

A. Based on my experience overseeing Brown's operation, there is a significant risk that capital expenditures to keep Brown operating will turn out to be higher than projected in the IRP modeling, and a very low likelihood that costs will be less. The timeline to replace Brown is a multi-year process and Vectren South may be boxed into making investments in Brown to enable it to continue reliably serving its customers while going through the process to procure reliable replacement generation.

Vectren South will minimize near term (2017-2023) investments previously planned while ensuring adequate reliability is maintained if a CPCN for the new CCGT is approved. Some examples of avoided capital and O&M work that would be required to keep Brown operating beyond 2023 are listed in **Table 2**. Completion of this work will not guarantee avoidance of other equipment failures.

Deferred Investment in Brown Due To Retirement	Cost
Water-Wall tube replacements	[redacted]
Additional cyber security investments	[redacted]
FD Fan overhaul dampers and housing (2)	[redacted]
Unit 2 economizer inlet header replacement	[redacted]
Replacement of insulation and ladding	[redacted]
Major ductwork and expansion joint replacement	[redacted]
Units 1 and 2 boiler chemical cleans	[redacted]
U2 catalyst replacement	[redacted]
Coal handling switchgear replacement	[redacted]
Superheater inlet tubes	[redacted]
Unit 1 superheat outlet header	[redacted]
Unit 1 and 2 coal pipe replacements (all straight runs)	[redacted]
Units 1 and 2 air heater overhauls	[redacted]
Unit 2 480 switchgear to operate plant equipment	[redacted]
Replacing the river well piping	[redacted]
Unit 1 480 switchgear to operate plant equipment	[redacted]
Unit 2 partial cooling tower cell rebuild	[redacted]
Turbine generator overhauls on both units	[redacted]
Total	30,290,000

Table 2

Q. The OUCC contends Vectren South should more thoroughly evaluate converting Brown to burn natural gas. Did Vectren South assess this option?

A. Yes. Vectren South engaged Babcock & Wilcox Co. to prepare an analysis of the coal-to-gas conversion. I agree with OUCC witness Alvarez that Brown could be converted to burn natural gas at a much lower up-front capital cost, but a gas-fired Brown would be very inefficient because of its high heat rate and fuel cost and rarely dispatched. In short, customers would be paying rates for capacity and then largely depending on MISO for energy purchases to actually serve their day to day needs. **Table 3** shows that the fuel cost (example has $4.00/mmBtu natural gas price) to generate a MWHr from a gas-converted Brown unit is $20 more expensive than a MWHr generated by the proposed "F" class CCGT.

	Heat Rate	Fuel cost/MMBtu @ $4/MMBtu Transportation	Approximate Fuel cost/ MWHr
Brown Coal Unit Converted to Gas	11,760	4.00	[redacted]
Proposed CCGT	6,560	4.00	[redacted]

Table 3

Q. Did Vectren South include any coal to gas conversion in its modeling?

A. Yes. Vectren South's initial IRP modeling considered, but did not select as a low cost resource, converting Culley Unit 3 to gas. In response to the OUCC's concerns, Vectren South witness Lind evaluated the total cost to ratepayers of a portfolio that converted Brown to operate on gas. This updated modeling demonstrates that it is more expensive when considering total costs to customers to convert Brown to operate on gas, primarily because of the need to make energy purchases to serve customers because of the high cost and inefficiency of a gas-converted Brown.

Q. Why would a utility convert a coal plant to burn gas given its inefficiency and high cost?

A. Utilities with large generation portfolios sometimes convert smaller coal units to burn gas if they need capacity. These utilities use their large, low cost generating units to serve customer load the majority of the time and cost effectively satisfy capacity needs to satisfy MISO's PRM with gas-converted coal plants.[3] In contrast, converting the Brown units to gas would leave Vectren South without sufficient low cost energy to serve its customers on a daily basis. For this reason, Vectren South's IRP modeling did not consider converting Brown to gas.

[3] Company witness Justin Joiner explains MISO's PRM in more detail. In short, MISO requires market participants to maintain a specified amount of capacity to ensure that the MISO region can satisfy needs experienced during peak periods.

Q. Mr. Alverez points to IPL Harding Street coal to gas conversion as an example of a low cost solution that has been successful. Does IPL's experience suggest converting Brown to a gas burning facility would be a prudent course?

A. No. IPL meets the criteria I just discussed—it has constructed a large new CCGT that can meet the majority of its needs and relies on Harding Street primarily for capacity. According to Harding Street EIA data provided as Petitioner's Exhibit No. 4-R, Attachment WDG-1R, the heat rate at Harding Street increased by approximately 15% and capacity factors have fallen from the 70% range into the teens. Harding Street's capacity factor is actually better than most coal to gas conversions and may indicate that transmission limitation around the Indianapolis area or other factors are helping Harding Street perform better than most coal to gas conversions. There have been 51 coal-to-gas conversions across the U.S. between 2013 and 2018. The majority were small units that converted to avoid high dollar investments to comply with the 2016 Mercury and Air Toxic Standard ("MATS") deadlines. The capacity factor for these units dropped from an average of over 40% to below 5% and heat rates rose from 10,800 to 12,500. Nineteen units in MISO have been converted from coal to gas and their heat rate increased from approximately 11,500 to 15,400 and capacity factors declined from a 60% average to less than 5%. Harding Street, MISO and Vectren South coal to gas conversion information is provided as Petitioner's Exhibit No. 4-R, Attachment WDG-2R.

Q. Are there any other potential costs to customers that Mr. Lind's modeling of gas-converted Brown units did not consider?

A. Yes. Because these units would not run frequently, customers could be exposed to congestion charges for the energy they require. The Locational Marginal Price ("LMP") paid for energy purchased from the MISO market consists of the energy, congestion and

line loss.[4] Transmission and distribution systems were designed to serve customers from local generation sources. When energy is imported from long distances, transmission lines can become stressed or overloaded. One way MISO balances the system and ensures reliability of the transmission grid is by assessing a congestion charge component of the LMP to encourage generation to operate (or be constructed) or not operate depending on the needs of the transmission system. Congestion can be positive, increasing the price MISO pays for energy incenting the seller to increase production or negative, which reduces the price MISO pays for energy incenting the seller to reduce or stop production.

Q. Do you have an example of how congestion can impact the LMP of non-localized generation?

A. Yes. Vectren South has two Purchase Power Agreements ("PPAs") in place for wind from Benton County Indiana with Benton County Wind Farm and Fowler Ridge II Wind Farm. **Table 4** shows the average five year congestion component of the LMP paid by Vectren South customers for the two wind farms compared to five year congestion component of local generation at the Brown and Culley locations. The congestion for the wind farms is much higher than for local generation. **Table 5** shows the number of hours that Vectren South has experienced negative LMPs for the two wind farms compared to Brown and Culley over the past 5 years. Note that there is a much higher congestion charge and many more negative LMP hours for generation that is farther from the load it is designated to serve.

[4] LMP is the hourly price for energy set by the last unit needed to meet demand in an area.

Generation Source	Day Ahead Average Congestion Component (Paid By Load) Of The LMP	Real Time Average Congestion Component (Paid By Load) Of The LMP
Brown		
Culley		
Benton County		
Fowler Ridge		

Table 4

Generation Source	Day Ahead Hours with Negative Pricing	Real Time Hours with Negative Pricing
Brown		
Culley		
Benton County		
Fowler Ridge		

Table 5

C. Risks With Continued Reliance on Culley Unit 2

Q. OUCC witness Aguilar contends Vectren South could continue to operate Culley Unit 2 and utilize the benefits of sharing environmental compliance equipment with Unit 3. (Public's Exhibit No. 1., p. 22). Why is the Company proposing to retire Culley Unit 2?

A. I explained in my Direct Testimony (Petitioner's Exhibit No. 4, p. 21) the reasons why retiring Culley Unit 2 is the best option for customers. Ms. Aguilar has not addressed any of the concerns with continued operation of Culley Unit 2 identified in my Direct Testimony. She relies only upon Culley Unit 2's ability to share environmental compliance equipment with Culley Unit 3, but fails to acknowledge that a minimum of $70 million in additional capital investments are required to continue operating Culley Unit 2 through 2036. In part, this investment is driven because Culley Unit 2 cannot solely rely on Culley Unit 3 for environmental compliance costs. A dry bottom ash system must be installed to comply with CCR and further investments may be required to comply with section 316b of the Clean Water Act (designed to protect fish and other aquatic wildlife at water intake and outfall structures) on the design and operation of the current river intake structure. In addition to these environmental costs, Culley Unit 2's

distributed control system ("DCS") is a Honeywell system installed in 2000 and must be updated or replaced because it is obsolete. A few other significant capital investments that would be required to keep Culley Unit 2 operating beyond 2023 include a turbine major overhaul, boiler acid clean, main transformer overhaul/replacement, major boiler component replacement, dry stack ductwork replacement, ID fan discharge ductwork, coal conveyor gallery replacement, boiler/high energy piping condition assessment, air heater basket replacement, continued overhaul of circulating water pumps and traveling water screens, and replacement of two 480-volt motor control center electrical switchgear.

Investing so heavily in a unit as old and inefficient as Culley Unit 2 is not economic. Vectren South's modeling bore this out. Due to the higher cost to operate, the unit has experienced less overall run time and much more unit cycling. Culley Unit 2 has reached the end of its useful life and should be retired rather than continuing to spend capital keeping the inefficient unit operating.

D. Risks From Continued Reliance on Warrick Unit 4

Q. What is the basic contractual arrangement related to Warrick Unit 4 with Alcoa?

A. Vectren South and Alcoa are parties to Joint Operating Agreement ("JOA") pursuant to which each has 50% ownership (150 megawatts ("MW") each) in Warrick Unit 4. Warrick Unit 4 came on line in 1970 and will be 54 years old in 2023. The unit sits on Alcoa property along with three other (150 MW each) units referred to as Warrick Units 1-3. Alcoa personnel are responsible for daily operations and maintenance decisions. Vectren South provides input through an Operating Committee that meets regularly.

Q. OUCC witness Aguilar testifies that she does not agree with Vectren's assessment of the risk of continuing to operate under the agreement and she specifically

describes that the OUCC does not agree with Vectren South's "presentation of the agreement." (Public Exhibit No. 1, p. 23). Please respond.

A. Witness Aguilar does not address Vectren South's specific concern that Alcoa has [redacted]. This concern was explained by the Company in the OUCC data request cited by Ms. Aguilar (Public's Exhibit No. 1, p. 23 fn. 31).

The original agreement provided Alcoa [redacted] and a 2001 amendment afforded either party the ability [redacted]. That [redacted] in a 2017 amendment due to ALCOA's corporate reorganization and operational uncertainty described by Company witness Chapman. Capital investments in Warrick Unit 4 must be evaluated in terms of the risk that Alcoa will exercise its [redacted] and, in effect, [redacted]. The decisions that might lead Alcoa to exercise its contractual rights arise from its own business economics and, particularly, the aluminum business.

Q. Are future environmental capital investments in Warrick Unit 4 necessary?

A. Yes. Due to compliance requirements coming in Alcoa's next NPDES permit, it is anticipated that the unit will require a significant capital investment to eliminate the plant's direct discharge to the Ohio River. This would require a Waste Water Treatment facility to treat the FGD waste stream and any process stream entering the ash pond prior to discharge. Also, Alcoa may be required to comply with section 316b of the Clean Water Act under this new permit which could include a reengineered design to the river intake system. Company witness Retherford discusses the Warrick site environmental risks in greater detail.

Q. Are there other factors that warrant against continued reliance on Warrick Unit 4?

A. Yes. Mr. Chapman notes that Vectren South wanted to keep one coal unit to avoid the all gas portfolio modeling demonstrated was the lowest cost portfolio. We focused on our best performing coal unit, Culley Unit 3. Warrick Unit 4 was considered, but the contractual concerns and the unit's performance led us to select Culley Unit 3.

Q. Please describe the performance issues at Warrick Unit 4 that made Culley Unit 3 a more attractive unit for the future.

A. The operating unit itself has become more susceptible to forced outages in recent years. **Table 6** shows that in all but one of the previous six years, the unit's EFOR has been well above the industry average of 8.56% with the last two years being over 17% (over twice the industry average).

	2012	2013	2014	2015	2016	2017
Warrick Unit 4 EFOR Rate	12.75	11.75	15.2	4.8	17.8	17.3

Source: PowerGADS (MISO) GORP Report
Table 6

Along with boiler tube failures, Alcoa has incurred multiple large mechanical and operational failures contributing to the high EFOR. Recent examples include a prematurely failed selective catalytic reduction ("SCR") catalyst layer, issues with air heater internals, boiler control failures due to DCS feedback and field device failures, and emission restricted shut downs. Warrick Unit 4 is also minimum load restricted (228-350 MWs) due to a failed duct burner on the SCR that maintains the unit's exit gas temperature minimizing unit corrosion due to flu gas reaching acid dew point.

E. Risks from Continued Reliance on BAGS Unit 2

Q. Please describe Vectren South's Broadway Avenue Gas Station ("BAGS") Unit 2.

A. BAGS Unit 2 is a simple cycle, 65 MW gas turbine constructed in 1981. The unit will be 44 years old when Vectren South projects retirement in 2025. BAGS Unit 2 will be well past its expected 30-year life. Due to its age, BAGS Unit 2 is not a very efficient unit, operating with a heat rate of over 14,000 in 2017 compared to the proposed new CCGT's anticipated heat rate less than half of this. Recall that a lower heat rate is indicative of greater efficiency.

Q. Are there risks with continuing to operate BAGS Unit 2 for the foreseeable future?

A. Yes. OUCC witness Alvarez's primary criticism is that Vectren South has provided insufficient support for the proposed retirement of BAGS Unit 2 (Public's Exhibit No. 2, p. 14). The data request response he refers to sought "any engineering or other technical reports performed by or on behalf of Vectren South identifying the need to retire the 'Natural Gas' units. The Company is not relying on engineering or other technical reports to support this conclusion. We are planning to retire it 14 years beyond its estimated useful life. As explained in the data request response, Vectren South has trained staff that includes a turbine engineer that supervises the operation and maintenance of the gas peaking units. Our staff has numerous years of experience operating and maintaining natural gas compressor and turbine/generator sets and intimate knowledge of BAGS Unit 2. They have assessed the condition of the unit and found significant risks with continuing to operate it.

Q. Please identify the specific concerns with continued operation of BAGS Unit 2.

A. During normal operation and maintenance activities, long term issues have been found which would require a major re-build of the unit to keep it operating beyond 2025. Our team has identified a damaged turbine casing, the need for exhaust diffuser replacement, replacements of multiple rows of blades and stationary vanes in both the

compressor and turbine, a requirement to re-wind the generator stator and rotor, first stage shroud block cracks, leading edge blade damage, and axial movement on the inner guide vanes. Vectren South's modeling appropriately called for the retirement of BAGS Unit 2.

Q. Does Vectren South take seriously its responsibility for keeping assets in good operating condition, operating efficiently, and attaining higher capacity factors?

A. Yes. Vectren South's success in this regard is supported by OUCC witness Alvarez's testimony noting how well our coal plants compare from an operational standpoint to other coal facilities in the nation. (Public's Exhibit No. 2, pp. 16-18). However, operating efficiently may mean determining when to retire units that are well past their useful lives rather than continuing to pour money into the units. Theoretically, Vectren South could ensure that it never retired any generation facilities if that was the goal. But that is not the goal. Throughout his testimony, OUCC witness Alvarez suggests that the only thing that matters in efficiently serving customers is maintaining sufficient capacity, by maintaining existing units, to ensure Vectren South can satisfy its MISO PRM requirements. However, determining the value in pouring money into old inefficient units with short life spans requires a more thorough analysis, including determining whether the existing units are still the most cost effective means of providing service.

Q. OUCC witness Alvarez contends the Company should not have included BAGS 1 in its list of units to be retired. (Public's Exhibit No. 2, p. 13) Why did Vectren South identify BAGS Unit 1 as a unit to be retired?

A. While Mr. Alvarez is correct that BAGS Units 1 has not received any capacity credit from MISO since 2014. Vectren South had classified BAGS Unit 1 in MISO's "temporary suspension" status for the allowable three years period. Prior to 2018, BAGS Unit 1 had

not been retired. A temporary suspension status allows a utility time to evaluate the failure of a unit to determine whether investments to bring it back on line are appropriate. BAGS Unit 1 failed in 2015 and the inspection to determine the scope of work and costs to repair the unit concluded that the estimated cost to get the unit operational would be $18 million and that further capital would be required to address several other issues to ensure long term reliability. The unit was 44 years old (same age BAGS 2 will be in 2025 when we are projecting it will retire) and well past its expected life of 30 years. The temporary suspension status provided Vectren South the option to spend the dollars to place the unit back in service prior to mid-2018 if it was determined beneficial. In early 2018, Vectren South submitted the necessary paperwork requesting permission to retire the BAGS Unit 1. The unit was officially retired in early 2018. Therefore, it was appropriate to identify it in the list of resources being retired from Vectren South's fleet.

F. Risks Of Delaying The Decision To Construct a CCGT

Q. Some have suggested that Vectren South should delay the decision to construct a CCGT and wait for the results of the 2019 IRP. Do you agree with this strategy?

A. No. This approach ignores (1) the timing by which Vectren South must make decisions about Brown's continued operation; (2) the timing required to construct a new CCGT and (3) the time required to complete a 2019 IRP and obtain a CPCN. Company witness Retherford explains that environmental regulations will require retirement of the Brown units on or before December 31, 2023 unless significant capital investments are made to have new systems operating well before 2023 as described by Company witness Retherford. When the 2019 IRP modeling is concluded and again recommends construction of a CCGT, there will not be sufficient time to construct the CCGT before Brown must be retired. I have provided a timeline as Petitioner's Exhibit 4-R, Attachment WDG-3R to highlight the challenges. The timeline shows the current

projected schedule in green and the timeline under the 2019 IRP in red. Delaying this would push the schedule out 2-3 years (2026/2027 timeframe), leaving customers vulnerable to market capacity and energy prices to reliably serve our customer base during this period. Such an approach would be highly risky and is not a prudent manner in which to operate a utility with an obligation and commitment to industrial, commercial, government, health care, schools and residential customers relying on us to provide reliable electric service.

II. The CCGT Is Reasonable

Q. Several of the intervenors have challenged the size of the proposed unit. Do you agree with their criticisms?

A. No. The primary unit Vectren South is proposing to build does not result in the Company having more capacity than is necessary to serve the projected load over the twenty year planning horizon. The proposed "F" class unit supplies about 700 MWs of baseload generation (prior to making a reduction for summer output and Unforced Capacity ("UCAP") associated with historical forced outage explained in more detail later in my testimony). A unit this size was required to keep costs low, efficiency high and obtain enough capacity to meet Vectren South's PRM with an extra 51 MWs in 2025. This replaces 730 MWs of baseload coal. Petitioner's Exhibit No. 4-R, Attachment WDG-4R, depicts how the baseload capacity matches Vectren South's anticipated needs from the 2016 IRP.

Q. Are there risks that the MISO PRM requirements change or that Vectren South's load increases rendering the additional capacity beneficial?

A. Yes. I discussed in my direct testimony examples of how the MISO PRM requirements have changed in the past and Company witness Joiner explains how the MISO PRM

requirement is established and several determining criteria that cause the level to fluctuate annually. I also discussed how holding a capacity surplus is necessary to ensure Vectren South can meet the annual changes in PRM requirements as well as attract new business.

Q. What is the basis for the contention made by the OUCC and ICC that the CCGT has more capacity than necessary for Vectren South to meet its projected needs?

A. Vectren South has proposed to add duct-firing to the CCGT. The duct-firing produces additional steam for the steam generator to increase the amount of electricity it can produce. The incremental cost of adding duct-firing is only $15 million and it produces approximately 150 MWs of additional capacity. The fired portion serves as peaking capacity, allowing Vectren South to supply energy during periods of peak demand and high market prices. Firing the unit cannot be cost-effectively added after the facility is constructed. While constructing the CCGT with duct-firing results in more capacity than our projections indicate is required, the relatively small cost and inability to add it later led us to propose this as part of the CPCN. The 2% increase in cost adds 20% of capacity. This extra capacity can be utilized to help attract new industrial and commercial customers to Evansville or sold into the wholesale market.

Q. Why do you refer to the duct firing as peaking capacity?

A. The air permit will limit the annual tons of Volatile Organic Compounds ("VOCs") being released from the CCGT. The VOCs increase on a per MWHr basis when duct firing which will limit the number of annual hours the unit can be duct fired without exceeding the annual VOC emission limit anticipated in the air permit. Vectren South will monitor VOC emissions and employ the duct firing when MISO demand and energy prices are highest, therefore, only operating during peak times. Vectren South's analysis indicates

that VOC emissions limit will not curtail use of the fired piece of the unit, but this limitation supports viewing the duct firing as peaking capacity because it will not be available at all times to serve Vectren South's typical demand.

Q. Does Vectren South have any recommendations if the Indiana Utility Regulatory Commission ("Commission") shares the concern about the need for the capacity resulting from firing the CCGT?

A. Yes. Vectren South witness Chapman has stated that Vectren South is willing to fund the duct-firing portion of the CCGT through shareholder dollars, exclude this piece from future rate base, and accept the risk to recover the investment through wholesale sales energy produced by the duct-firing.

Q. Besides being the lowest cost option for the customer what are some of the other reasons a CCGT is a practical option?

A. The "F" class technology is a highly durable, proven design that has logged numerous operating hours across the power industry. Given the current MISO market and projected market changes discussed by Vectren South witness Joiner, the CCGT has the necessary operating characteristics and flexibility to better react to changing demand and provide the reliable service to our customers. First, the CCGT can ramp output up and down at a rate of 80 MWs per minute providing the flexibility to meet the changing demand requirements created by intermittent resources. This compares to our current coal units that ramp output up and down at a rate of 3 MWs per minute. Second, the unit will be designed with the ability to cycle off and back on nightly if necessary to allow customers to take advantage of low market prices during the off-peak hours when available. The proposed CCGT can start back up from a cold condition in less than an hour, warm condition in 30-40 minutes and hot condition in less than 30 minutes. The

Brown units require 18-24 hours for a cold start, 8-12 hours for a warm start and 4-8 hours for a hot start. The ability to ramp output, cycle on/off quickly and provide reliable capacity as units age are characteristics that have a high probability to create financial benefit in a MISO market that has already moved to a 5 minute pricing settlement period and is exploring market reforms that will reward unit flexibility in the ancillary services market discussed by Company witness Joiner.

The 2x1 "F" class unit consists of 2 sets of compressors, natural gas turbines and generators, heat steam recovery generators (boilers that convert water into steam) and one steam turbine and generator. Simplistically, air is pulled into each of the two compressors where it is compressed to high pressure, is mixed with fuel and ignited. This ignition and combustion moves a hot air fuel mixture through the gas turbine turning blades which drive a shaft within the associated generator producing electricity. The waste heat from each gas turbine enters its associated heat recovery steam generator ("HSRG") where purified water is heated and turned into steam. The high pressure steam enters the turbine. As the steam flows through the turbine blades, the blades turn a shaft connected to the generator. As the generator spins it produces electricity. This design is very efficient as the waste heat from the gas turbines is used to generate more electricity rather than being vented to the atmosphere. The unit has a wide range of output as it can be operated in a 1x1 configuration (one gas turbine/generator, one HRSG and one steam turbine/generator) producing over a range of approximately 180-420 MWs or a 2x1 configuration (two gas turbines/generators, two HRSG's and one steam turbine generator) producing over a range of 380-700 MWs. Duct firing can then be added for peaking. This provides a much wider range of output which is especially beneficial in the off–peak hours when demand and prices are low. Currently the normal minimum output for the Brown units is 135MWs each, Warrick 4 minimum is 114 MWs

and Culley 2 minimum is 50 MWs. This means that there are hours during the off-peak when MISO market prices are lower than the cost of our coal units but they can only turn down to 434MWs as compared to the CCGT which can turn down to 180 MWs in the 1x1 configuration and 380MWs in the 2x1 configuration.

Q. Why is the CCGT the lowest cost option?

A. The two primary reasons are the low cost of natural gas and the high efficiency rating of new CCGT technology as compared to Vectren South's coal fleet. The primary measure of efficiency of an electric generation unit is heat rate. Heat rate is the amount of energy in British thermal units ("Btus") used to generate a kilowatt hour ("kWh") of electricity. Heat rate can be expressed in "gross"; the Btu/kWh of total output of the generator (not including electric consumption to operate plant equipment) or "net"; the Btu/kWh (including electrical consumption to operate plant equipment). The lower the heat rate or number of Btu's required to produce a kWh of electricity the more efficient the generating source.

Q. How does the heat rate of the proposed CCGT compare to the coal units that intervenors are recommending Vectren South continue to operate?

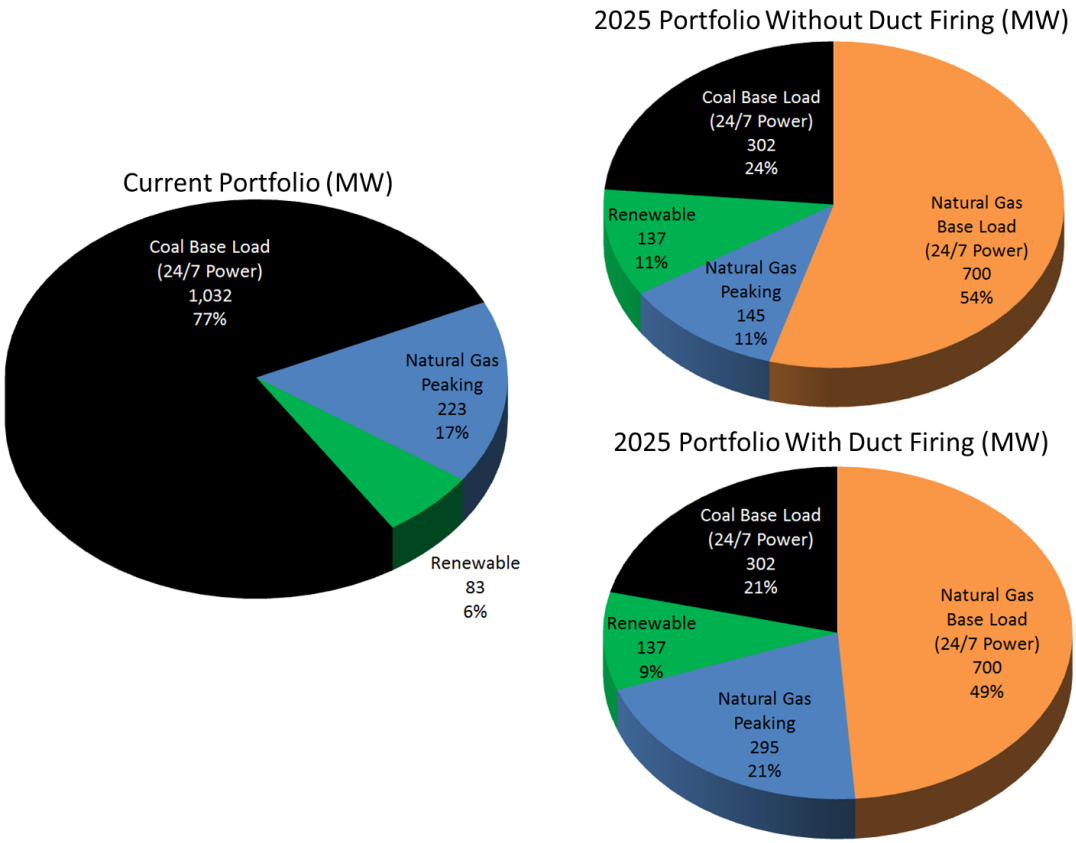
A. The proposed CCGT is expected to operate at an average heat rate of approximately 6,560 Btu/kWh. **Table 7** shows the heat rate of the Vectren South coal fleet.

	2017 Net Heat Rate
AB Brown Unit 1	11,576
AB Brown Unit 2	11,007
FB Culley Unit 2	12,662
FB Culley Unit 3	10,549
Warrick Unit 4	10,896
Vectren Coal Fleet Average	11,001
Typical "F" Class CCGT	6,560

Table 7

Q. OUCC witness Alverez (Public's Exhibit 2, p. 10) claims that Vectren South's preferred plan does not diversify its generation but swings the pendulum from 77% coal to 77% gas. Do you agree with his assessment?

A. No. Fuel diversity can be viewed from the perspective of baseload generation, peaking generation and intermittent generation. As discussed earlier, the Company views duct-firing as peaking generation. As shown in the pie charts below, Vectren South currently has 100% of its baseload capacity supplied by coal. In both the fired and unfired portfolio, this changes to 70% natural gas and 30% coal. When looking at the total portfolio, Vectren South currently has 78% of its total capacity supplied by coal, 16% natural gas peaking and 6% intermittent renewables. In the preferred portfolio with a fired CCGT scenario Vectren South will have 49% baseload gas, 21% baseload coal, 21% peaking gas and 9% intermittent renewables while the unfired portfolio would have 54% baseload gas, 24% baseload coal, 11% peaking gas and 11% intermittent renewables.



Q. Are you concerned that constructing the proposed CCGT is moving to a position of having too much reliance on one unit?

A. No. Although there may be certain advantages to have more than one CCGT, the cost of building the gas pipeline infrastructure, site preparation, engineering, and procurement of equipment construction and interconnect costs of two smaller units outweigh the benefits. The efficiency benefits and cost savings associated with building one larger CCGT is the best option. Building a 2x1 configuration allows Vectren South the flexibility to take one of the gas units off line for planned maintenance in the shoulder months when demand is lowest and operate in a 1x1 configuration producing up to 420 MWs. This energy along with the remainder of Vectren South's fleet will supply enough energy to serve Vectren South shoulder month demand the majority if not all of the time. As mentioned earlier although Vectren South doesn't feel it prudent to rely on the MISO

market for energy and capacity for long stretches we should, as MISO members, be able to rely on the market to supply energy in short stretches. If the entire unit is offline for maintenance or to address an operating issue, Vectren South would still have adequate energy with coal and renewables to meet over 40% of its peak demand.

Q. Does Vectren South expect to receive 850 MWs of capacity credit towards its PRM from the CCGT?

A. No. A CCGT's output is dependent on several variables; one being air density. Air density changes with the temperature. During the winter months air density is higher resulting in a CCGT producing more output. Air density in the summer months when temperatures rise to 90 plus degrees is lower resulting in a reduced output. In addition, as discussed by witness Joiner, MISO also penalizes units based on their UCAP performance history. Simplistically, UCAP is based on the demonstrated output of a unit under peak load conditions and percent of time it is not participating in the market due to being forced off-line as a result of operational or maintenance issues. Until the equipment manufacturer is chosen through a competitive bidding process the final summer output will not be known. Each year the UCAP values will change based on previous performance. As a result capacity credit for the unfired and fired portion of the CCGT can be different each year.

III. Cost Estimate Is Reasonable

Q. Did Vectren South develop a detailed cost estimate for the CCGT?

A. Yes. Vectren South witness Diane M. Fischer described in detail the extensive effort the Company invested in developing a very detailed cost estimate for the CCGT. While Ms. Fischer describes the process in great detail, it is important to emphasize that B&V, on behalf of the Company, solicited and evaluated competitive bids for all equipment and

construction for the CCGT based on conceptual designs of the CCGT. Ms. Fischer states that the cost estimate represents a +/- 10% estimate for equipment and construction.

Q. Mr. Alvarez criticizes Vectren South's cost estimate (Public's Exhibit No. 2, p. 26) alleging that Company witness Fischer "cannot stand behind [the] estimate without qualifications." Is his criticism valid?

A. No. Vectren South, in conjunction with B&V, has produced a very comprehensive and accurate cost estimate with a plus or minus 10% margin of error. It is still a cost estimate and the actual price may deviate somewhat from this estimate. However, the fact that this is an estimate does not render it unreliable for purposes of Commission consideration. Mr. Alvarez implies that rather than presenting the Commission with a cost estimate, it must provide an unqualified bid to construct the project for a set price. His position ignores that Ind. Code § 8-1-8.5-5(a) requires the submission of a cost estimate, not a firm price.

Q. Mr. Alvarez further criticizes the estimate for not being the result of a competitively bid engineering, procurement or construction contract. Do you agree with him?

A. No. As Mr. Alvarez recognizes, Ind. Code § 8-1-8.5(e)(1)(A) requires the estimated costs of the proposed generation facility of more than 80 megawatts to be "the result of competitively bid engineering, procurement, or construction contracts, as applicable" "to the extent commercially practicable." (Emphasis added) He disregards Vectren South witness Fischer's testimony that Vectren South's cost estimate is the result of competitively bid procurement and construction contracts. Petitioner's Exhibit No. 6, pp. 36-37. Mr. Alvarez may be ignoring the use of the conjunctive "or" in the statute and

misreading the statute as requiring presentation of an engineering, procurement and construction or EPC contract. In an EPC contract, the contractor is responsible for obtaining all specified equipment, designing the plant, constructing the plant and assuming the project cost. The statute does not require an EPC contract as evidenced by the language providing the option of competitively bid engineering, procurement or construction contracts.

Q. Would it be commercially practicable for Vectren South to obtain an EPC contract bid and present it to the Commission in conjunction with a CPCN request?

A. No. A contractor offering a bid on a contract incurs significant expense in developing these bids. Costs can range from $300,000 to $1 million for the bid preparation. An EPC contract often includes a firm price, which requires the contractor to be very thorough in providing a bid. Contractors will not put the investment into developing firm bids simply for Vectren South to submit them to the Commission for approval in a CPCN proceeding. The length of time required for approval of a CPCN also makes it commercially impracticable to obtain a firm EPC contract bid as conditions change over time (supply & demand impacting commodity prices, labor market availability, *etc*.) resulting in high contingency being included in the firm bids to ensure adequate profit margins. In addition waiting for a CPCN places Vectren South in a much better position to create a competitive market and negotiate terms as bidders will be much more serious once they know there is an actual project they are investing the time and effort to earn.

Q. Do you agree with Mr. Alvarez that there are "red flags" in the proposed cost estimate that signal price escalation, construction-scheduling uncertainty, and lack of general confidence in its ability to undertake projects of this magnitude (Public's Exhibit No. 2, p. 28)?

A. No. Vectren South employed B&V to develop this +/-10% cost estimate as they have extensive experience as an EPC contractor and an Owners Engineer involved in several CCGT projects. They used the same cost estimating practices and review they use when bidding a project as an EPC. The typical costs for an "F" class combined cycle gas turbine project are well known as there are over 258,000MWs of combined cycle output in the United States. This is in contrast to the Edwardsport and Mississippi Powers Integrated Gasification Combined Cycle ("IGCC") technology that Industrial Group witness Michael Gorman unfairly points to as examples of over budget and over schedule projects. These were first of a kind technology projects that were not proven. Vectren South originally partnered with Duke on Edwardsport but bowed out before the project started largely because of the difficulties confirming the prices.

The OUCC's "red flags" comment ignores the entire body of work performed by Vectren to put together a very detailed estimate for the Commission. Vectren South and B&V performed a significant level of conceptual design to develop the estimate for the CCGT. This includes development of site arrangement drawings, a full set of flow diagrams, a detailed bill of quantities, a detailed project execution plan and construction plan, a level one schedule, one line diagrams and project sequencing plans to ensure that the estimate was suitable for the Company's use in obtaining approval from the Commission. In addition, as stated in Ms. Fischer's testimony, the estimate "represents a +/- 10% estimate for equipment and a +/- 10% estimate for construction."

B&V followed the same procedures and practices for developing the project cost as would be used for projects where they are the EPC Contractor. This same estimating template was used for the following B&V EPC projects listed in **Table 8** (provided by B&V). These examples demonstrate that B&V has the experience with several CCGT

projects that have been completed on schedule and on budget, further supporting the reasonableness of these cost estimates.

Project Name	CT Model	Configuration	% Complete	On Budget	On Schedule
Tenaska Westmoreland	Mitsubishi M501J	2x1 CCPP	90%	Y	Y
Oregon Clean Energy	Siemens SGT6-	2x1 CCPP	100%	Y	Y
Enmax Shepard	MHI M501G	2x1 CCPP	100%	Y	Y
FPL Ft. Myers	GE 7FA.05	2x0 SCPP	100%	Y	Y
FPL Lauderdale	GE 7FA.05	5x0 SCPP	100%	Y	Y
Westar Emporia	GE 7FA & LM6000	7x0 SCPP	100%	Y	Y

Table 8

Q. Did Vectren South omit the costs for the lateral pipeline to serve the proposed CCGT from its cost estimate as Mr. Alvarez alleges (Public's Exhibit No. 2, p. 27)?

A. No. It was included as fixed O&M costs, as was indicated in response to discovery.

IV. Recommendations For CCGT Cost Exposures

Q. Industrial Group witness Gorman makes several recommendations for contractual protections when negotiating an EPC for the CCGT. Will Vectren South consider these recommendations?

A. Yes. Mr. Gorman recommends that Vectren South include appropriate contractual provisions that shift the risk of cost overruns on the CCGT to the Company's major equipment suppliers or the EPC contractor. He also recommends performance obligations in its supply contracts to ensure that a new CCGT can meet these expected operating performances.

Q. Has Vectren South decided what method it will utilize to contract for the engineering, procurement and construction of the CCGT?

A. No. Vectren South leans towards and desires a fixed price EPC contract with payments made as specific quality, productivity and performance milestones are achieved. This approach would shift many of the risks of cost overruns to the EPC contractor. We will hire an Owners Engineer with EPC experience to help guide us through the best way to structure the EPC contract to ensure the project is completed on schedule and within budget. 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. Even with a firm price, there are risks of change orders and unanticipated issues that can impact the price.

Q. Has Vectren South decided whether it will require performance obligations in any agreement with an EPC contractor?

A. Yes. Specific performance obligations associated with project milestones will be established. Cost sharing incentives for completing specific phases of work under established budgets is something that has worked well for Vectren South on previous capital projects and will be something we'll explore for this project.

Q. Mr. Gorman also recommends that Vectren South share all of the wholesale power margins generated by the plant with customers. Has Vectren South considered this recommendation?

A. Yes. The parties are correct that a significant benefit of the new CCGT is the enhanced ability to participate in the MISO energy market because of the unit's greater efficiency. Vectren South witness Chapman has agreed that in the Company's next base rate case, it will agree to modify its wholesale power sharing mechanism to adjust the portion of

wholesale sales shared with customers from 50% to 100%. As Company witness Lind explains, this will further improve the benefits to customers from the CCGT.

V. Alternative FGD Options Were Explored

Q. Please describe the process Vectren South engaged in to explore scrubber options for Brown.

A. Vectren South hired B&McD to assess the condition of the Brown Scrubber, the estimated remaining life and estimated replacement cost. B&McD associates visited the Brown plant to view and assess the condition, examine historical maintenance documents, become familiar with other environmental controls and how they interact and understand the characteristics of the coal burned.

Q. Why did Vectren South focus on the wet limestone FGD?

A. Based on its investigation, B&McD considered options and concluded that Wet Limestone Forced Oxidation ("LSFO") was the best option for the Brown plant. They based this decision on size of the Brown units and the long track record of high SO_2 removal rates and high operating reliability on high sulfur coal applications. B&McD did consider other technologies, contrary to OUCC witness Aguilar's assertion that no other technologies were evaluated (Public's Exhibit No. 1, p. 20). These were ruled out by B&McD due to their lack of a track record of performance on high sulfur coal, higher long term O&M costs, addition of new environmental equipment such as a fabric filter downstream of the process, concerns with impact to fly ash quality and interaction with other plant environmental controls. Solid performance with high sulfur coal is critical as there is always the possibility for lowering SO_2 removal requirements and emission allowances.

Q. Is the Company presenting additional evidence to demonstrate that other scrubber technologies are not viable?

A. Yes. Vectren South witness Farber has evaluated the scrubbers the OUCC and ICC claim should have been further reviewed and explains why those options are either economically or operationally problematic.

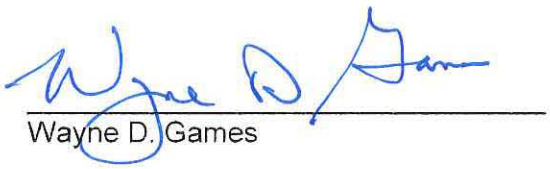
VI. Conclusion

Q. Does this conclude your prepared rebuttal testimony?

A. Yes, at this time.

VERIFICATION

The undersigned, Wayne D. Games, affirms under the penalties of perjury that the answers in the foregoing Rebuttal Testimony in Cause No. 45052 are true to the best of his knowledge, information and belief.



Wayne D. Games

Corrosion Projects 2008-2018

	Grand Total Spend	**$**	**32,081,501**
	Avg Yearly Spend	**$**	**2,916,500**

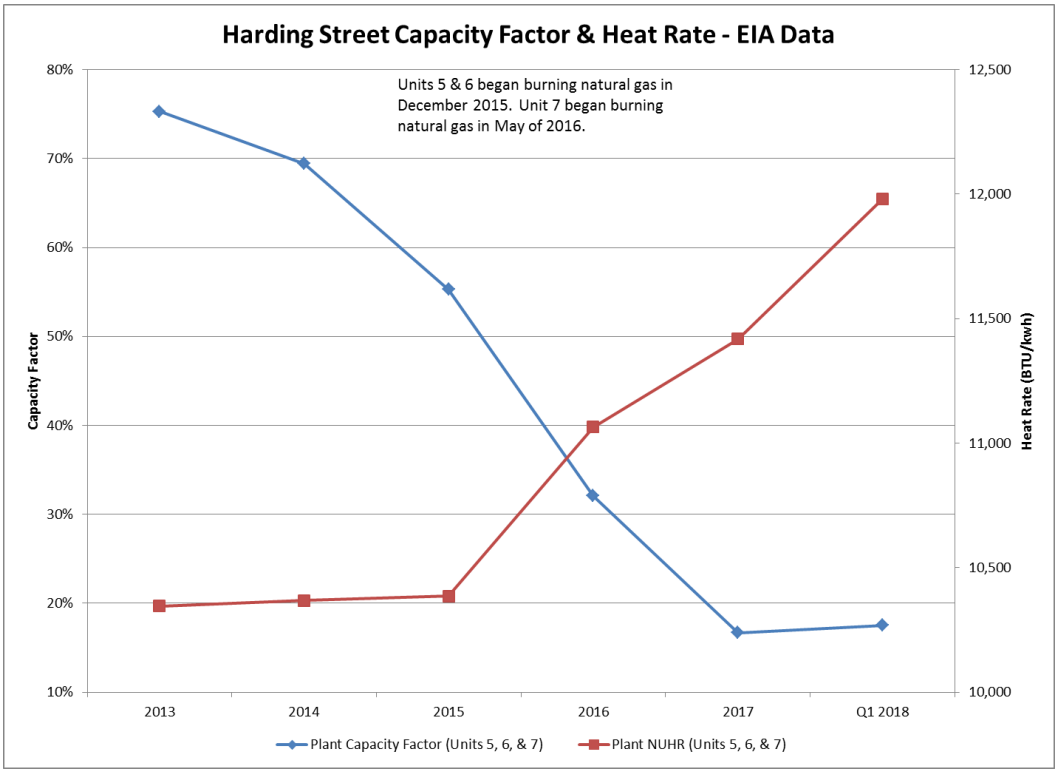
Projects by Year

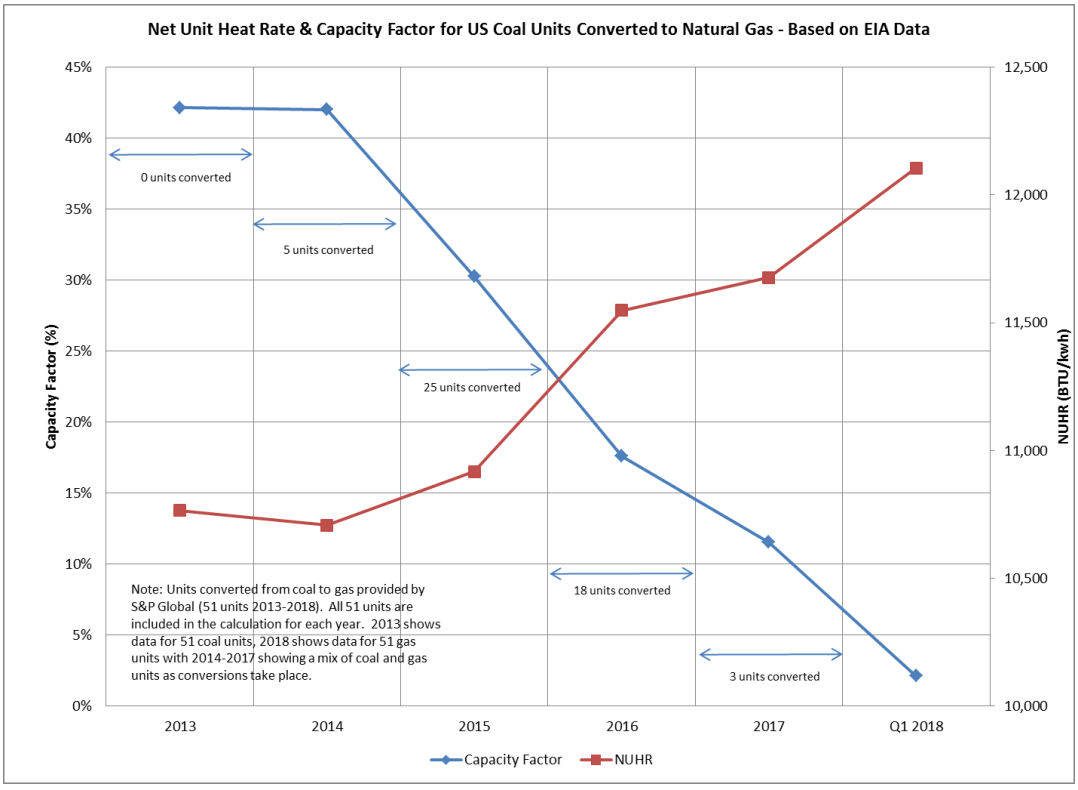
	2018		**Cost**
1	U1 North/South Tower Phase 2	$	886,000
2	U1 - U2 Walk Way	$	350,000
3	U2 Inlet Duct Platforms	$	150,000
	Total	**$**	**1,386,000**
	2017		
1	U2 Coal Silo Replacement/Repair	$	1,000,000
2	U1 North/South Absorber Duct Tower Replacement	$	1,800,000
3	U1 North/South Absorber Duct Tower Replacement Phase 2-4	$	400,000
	Total	**$**	**3,200,000**
	2016		
1	U1 Coal Silo Vertical Wall, Cone Weld Replacement	$	2,900,000
2	U1 Belt Filter Replacement	$	1,300,000
3	U1 Truck Chute Replacement	$	200,000
4	U2 North/ South Tower Absorber Duct Support Tower Phase I	$	250,000
5	U2 Coal Silo Cone Repairs	$	175,000
6	U2 Coal Silo Vertical Wall Assessment	$	25,000
7	U1 Belt Filter Temporary reenforcement	$	10,000
8	U2 Cooling Tower Cell D,E,F &G Structure and Face replacement	$	480,000
9	Coal Yard Hoppers (5)	$	650,000
10	U1/U2 FGD Corrosion Study	$	40,000
11	Ranney Well Floor Sturcture	$	30,000
	Total	**$**	**6,060,000**
	2015		
1	U2 North Belt Filter reenforcement	$	10,000
2	U2 FGD Chute replacement	$	200,000
3	U1 Stack (32) Lower stack band replacement	$	300,000
4	U1 Stack Fan replacement (2)	$	100,000
6	FGD Lime Silo Roof Replacement	$	800,000
7	U2 FGD Building / Floor Structure/ Drains	$	300,000
8	U1 FGD Building Structural/ Columns	$	250,000
9	Coal Hopper (1)	$	200,000
10	U2 FGD Building South Wall Replacement	$	150,000
11	U1 Lime Mixing Tank Stair Tower	$	78,000
	Total	**$**	**2,388,000**
	2014		
1	U2 FGD Thickener Tank Bridge Structure repairs and coating	$	275,000
2	U1 FGD Building Structure and Walls - South and East	$	300,000
3	Carboline Facility Coating Assesment		NA
4	U2 CT Cell Replacement A, B & C	$	3,400,000
5	U2 Lime Mixing Tank Emergency Repairs and Shoring	$	30,000
	Total	**$**	**4,005,000**

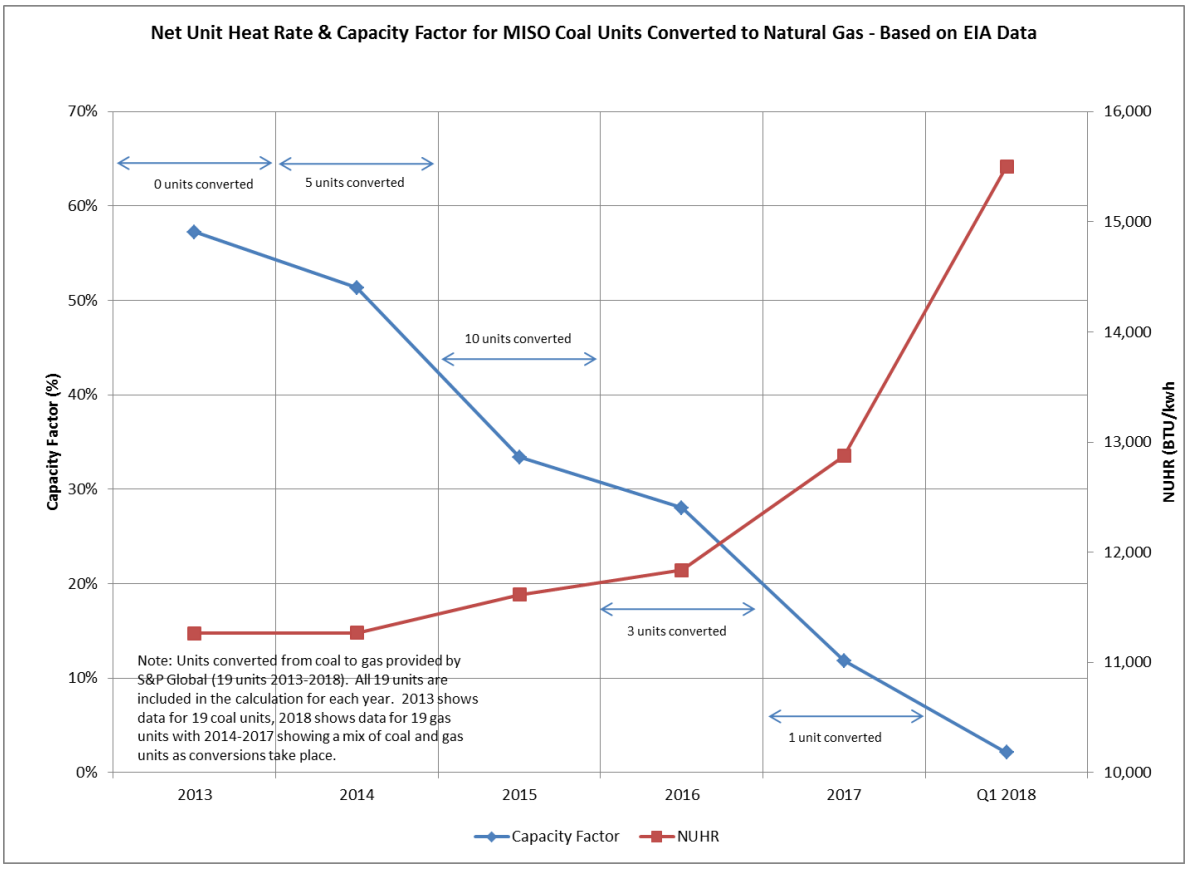
	2013		
1	U2 South Belt Filter Structure Replacement	$	600,000
2	Coal Conveyor C Truss Connecting plate seal and and coating	$	150,000
3	Train Trestle Rebuild	$	2,300,000
4	U2 Absorber Tower Coating	$	800,000
5	U1 Lime Mixing Tank Replacement	$	750,000
6	U1 FGD Pump Room Structure/ Siding and foundation replacement	$	400,000
	Total	**$**	**5,000,000**
	2012		
1	U1 FGD Building Structure and Walls - North and West	$	200,000
2	U1 Cooling Tower Replacement Cells A-G	$	5,950,000
3	U1 Absorber Tower Coating	$	800,000
	Total	**$**	**6,950,000**
	2011		
1	U2 FGD Building Structural Steel and Siding Replacement	$	1,100,000
	Total	**$**	**1,100,000**
	2010		
1	Repair of handrails, ladders, and platform grating on Unit 2 precipitator	$	135,401
2	U1 Outage Cleaning and Patching Holes on Thickener Tank	$	115,851
3	U2 SCR MCC cable enclosure rusted	$	66,767
4	U1 FGD MCC Bldg	$	51,628
	Total	**$**	**369,647**
	2009		
1	PHASE 3 ABB2 FGD (2009) corrosion repair U2	$	395,063
2	3I Eng Study	$	108,170
3	PHASE 3 ABB1 FGD (2009) corrosion repair U1	$	100,264
4	3I Engineering Study	$	93,270
5	Top Edge SE side - Thickner Tank	$	83,299
6	3I Engineering to perform a structural analysis of the FGD area	$	72,784
7	3I Engineering to perform a structural analysis of FGD area	$	63,769
	Total	**$**	**916,619**
	2008		
1	Phase 2 Corrosion repairs - 3I Eng , structural repairs U2 scrubber	$	315,184
2	Phase 2 Corrosion repairs - 3I Eng , structural repairs U1 scrubber	$	211,511
3	UNIT 1 FGD PLATFORM AND HANDRAIL SYSTEM CORROSION REPAIRS	$	179,541
	Total	**$**	**706,236**

Petitioner's Exhibit No. 4-R, Attachment WDG-2R

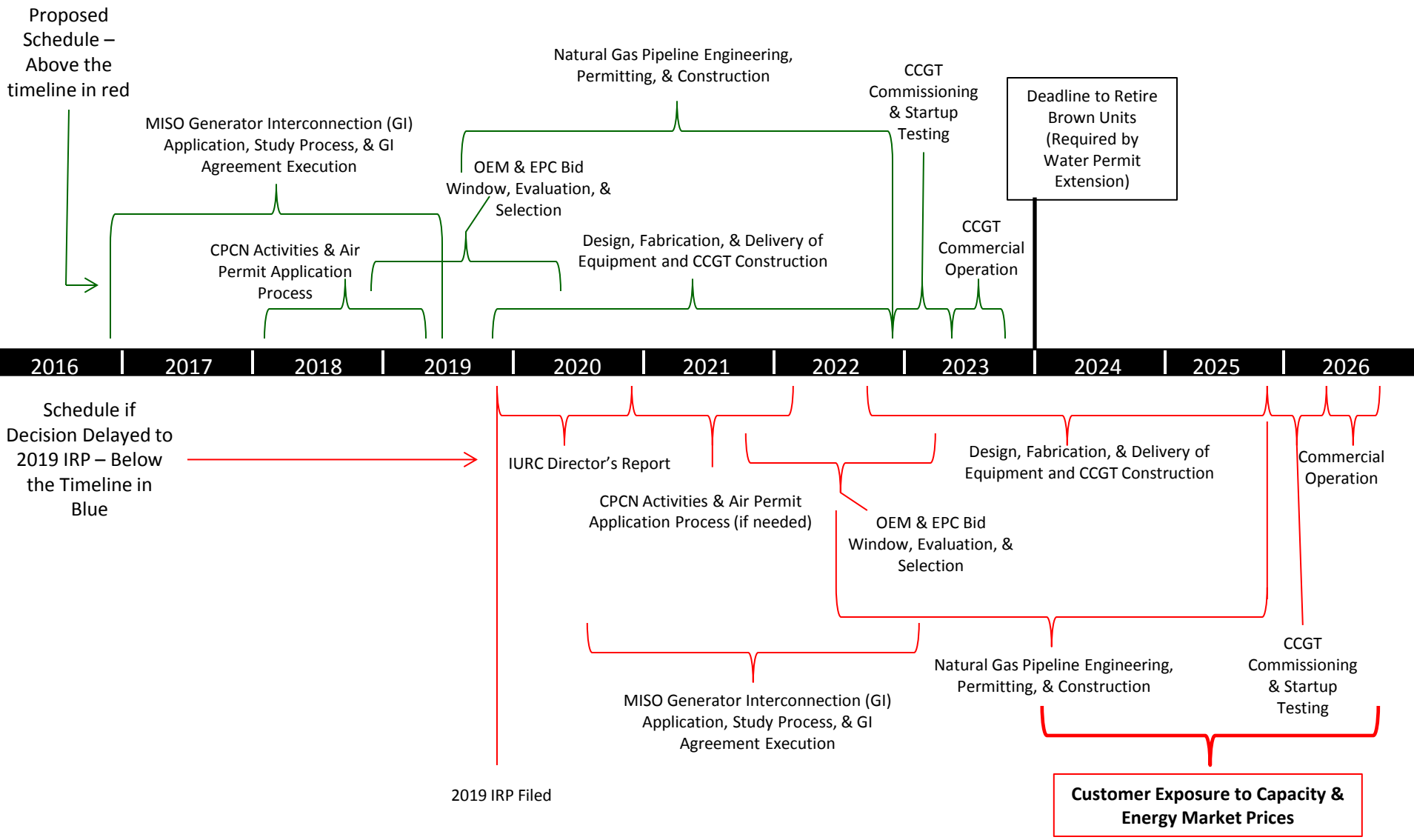
Cause No. 45052

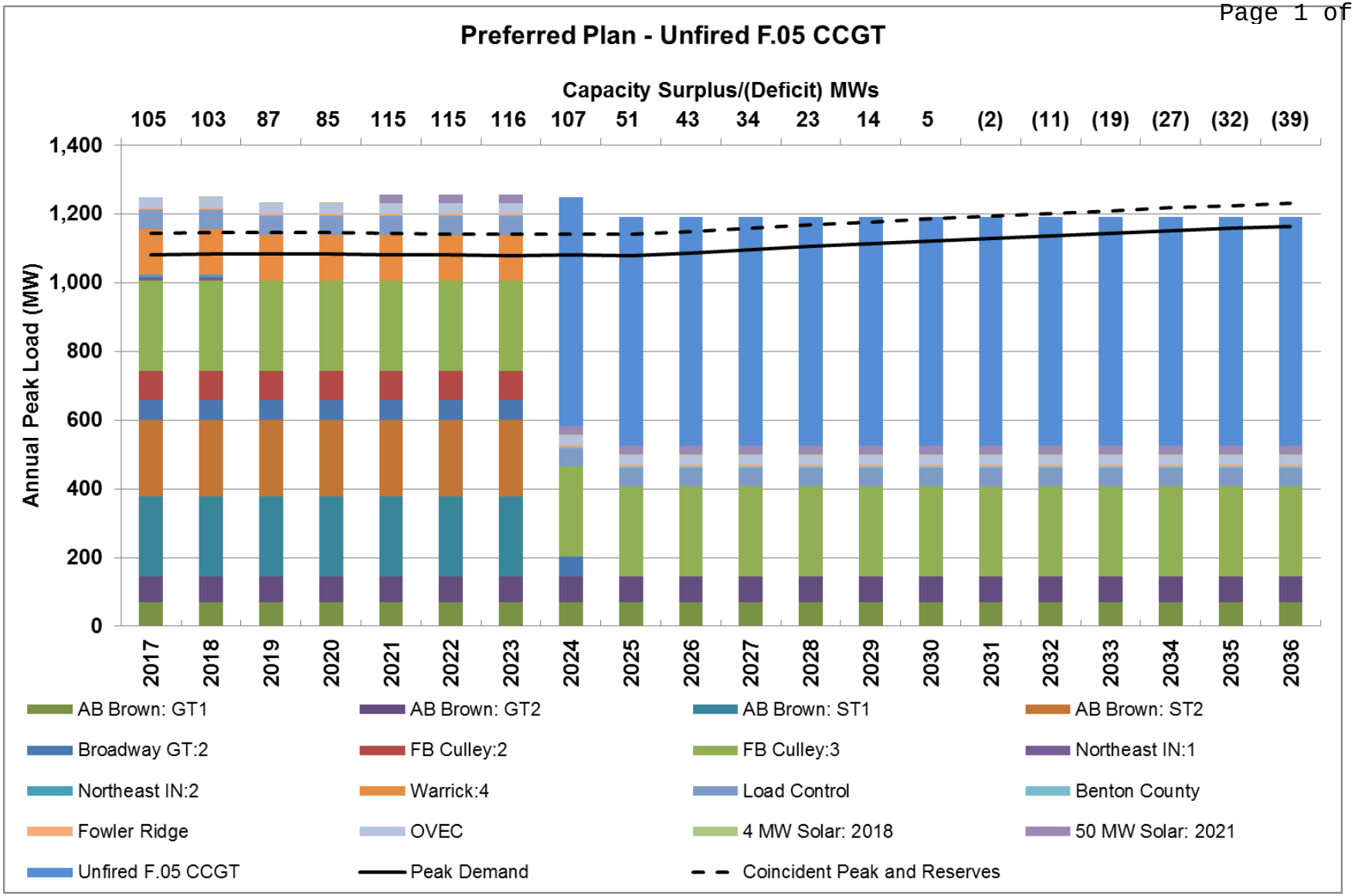





Net Unit Heat Rate & Capacity Factor for MISO Coal Units Converted to Natural Gas - Based on EIA Data
Capacity Factor (%)
NUHR (BTU/kwh
70%
60%
50%
40%
30%
20%
10%
0%
16,000
15,000
14,000
13,000
12,000
11,000
10,000
0 units converted
5 units converted
10 units converted
3 units converted
1 unit converted
Note: Units converted from coal to gas provided by S&P Global (19 units 2013-2018). All 19 units are included in the calculation for each year. 2013 shows data for 19 coal units, 2018 shows data for 19 gas units with 2014-2017 showing a mix of coal and gas units as conversions take place.
2013
2014
2015
2016
2017
Q1 2018
Capacity Factor
NUHR

CCGT Timeline of Activities




Preferred Plan - Unfired F.05 CCGT
Capacity Surplus/(Deficit) MWs
105 103 87 85 115 115 116 107 51 43 34 23 14 5 (2) (11) (19) (27) (32) (39)
Annual Peak Load (MW)
1,400
1,200
1,000
800
600
400
200
0
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036
AB Brown: GT1
AB Brown: GT2
AB Brown: ST1
AB Brown: ST2
Broadway GT:2
FB Culley:2
FB Culley:3
Northeast IN:1
Northeast IN:2
Warrick:4
Load Control
Benton County
Fowler Ridge
OVEC
4 MW Solar: 2018
50 MW Solar: 2021
Unfired F.05 CCGT
Peak Demand
Coincident Peak and Reserves