SOUTHERN INDIANA GAS AND ELECTRIC COMP

D/B/A

VECTREN ENERGY DELIVERY OF INDIANA, INC.

CAUSE NO. 45052

VERIFIED (PUBLIC) DIRECT TESTIMONY

OF

WAYNE D. GAMES

VICE PRESIDENT OF POWER SUPPLY

SPONSORING PETITIONER'S EXHIBIT NO. 4 ATTACHMENT WDG-1

VERIFIED DIRECT TESTIMONY

OF

WAYNE D. GAMES

VICE PRESIDENT OF POWER SUPPLY

Q. Please state your name and business address.

A. Wayne D. Games, One Vectren Square, Evansville, Indiana 47708.

Q. What position do you hold with Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South" or the "Company")?

A. I am Vice President of Power Supply.

Q. Please describe your educational background.

A. I received a Bachelor of Arts in Industrial Technology from Ohio Northern University in 1980 and a Master of Arts in Management from Antioch University in 2002.

Q. Please describe your professional experience.

A. I have over 26 years of varied experience in the utility industry. I started my career with The Dayton Power & Light Co. in 1991 where I held supervisory, manager, and regional manager titles on the energy delivery side of the business. Upon joining Vectren in 2000, I served as Director of Construction and Service and Regional Manager in the Ohio service area. In 2003 I moved to Evansville, Indiana and accepted responsibility as Director of Vectren South's A.B. Brown generating station. I was promoted to Vice President of Power Supply in April of 2011.

Q. What are your duties and responsibilities as Vectren South's Vice President of Power Supply?

A. I am responsible for the overall budgeting, operation, maintenance and personnel decisions for the power generation fleet of Vectren South. In addition, I have responsibility for ensuring that the demand of our customers is met at the lowest reasonable cost through the production and purchase of electric energy necessary to meet the needs of our jurisdictional customers. I am responsible for completing these functions while ensuring final compliance with the environmental requirements of all applicable agencies, including the Indiana Department of Environmental Management ("IDEM") and the United States Environmental Protection Agency ("EPA").

Q. Have you previously testified before this Commission?

A. Yes. I regularly testify in the Company's fuel adjustment clause ("FAC") proceedings and related sub dockets in Cause No. 38708. I also testified in support of Vectren South's proposal to install pollution control equipment on its coal-fired generation facilities in Cause No. 44446 and construction of solar facilities in Cause No. 44909.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit	Description
Petitioner's Exhibit No. 4, Attachment WDG-1	A.B. Brown Scrubber Assessment

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

A. Yes. It is important to recognize, however, that other Vectren South employees and consultants with specific areas of expertise engaged by the Company were involved in the process of these studies. I served the role of overseeing the project's planning process.

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

A. My testimony will describe Vectren South's current generation fleet, including challenges facing that fleet. I will explain the Company's decision to construct a new combined cycle gas turbine ("CCGT") on available property at its Brown Generating station. I explain the impact this will have on the Company's current generation fleet and the basis for cost estimates for the CCGT. I will describe proposed improvements to the Company's Culley Unit 3 generating facility to enable it to continue serving our customers. I will update the Commission on the investments made to our existing generation facilities to comply with the mercury air toxics standards ("MATS") and other federal regulations, thereby allowing our coal units to operate through 2023. Finally, I will describe why the proposed projects are in the public interest and I will support the Company's proposal for ongoing Commission review.

I. Vectren South's Existing Facilities

Q. Please describe Vectren South's current base load generation portfolio.

A. Vectren South operates the following five (5) coal-fired base-load units:

Unit Name	Net Output (MW)	In-Service Date
Culley 2	90	1966
Culley 3	270	1973
Warrick 4[1]	150	1970
Brown 1	245	1979
Brown 2	245	1986

Q. How have Vectren South's coal plants historically been operated?

[1] Warrick 4 is a 300 MW unit co-owned with Alcoa Generating, Inc. The identified net output represents Vectren South's 50% ownership in the unit.

A. Vectren South's coal plants have historically been operated as base load units. Base load units are designed and operated to satisfy the minimum level of demand on an electric grid during an average day. Consequently, these facilities were designed and built to reliably and efficiently operate around the clock with relatively stable output to meet customers' electric needs. For decades, Vectren South's coal facilities were the most economical option for electric generation and have been the first to dispatch and produce on a regular basis.

Q. Have there been changes in the way these units operate in the past five to ten years?

A. Yes. These plants were originally built with the purpose of reliably serving the electric needs of Vectren South customers and utilized Indiana coal as fuel for the units. For years, the abundance of low cost coal mined locally in Indiana made these plants very competitive. However, costs began to rise as environmental regulations required investment in environmental control equipment and incremental variable costs to operate this equipment. The market in which these facilities operate also began to change. Indiana electric utilities, with encouragement from the Commission and the Federal Energy Regulatory Commission ("FERC"), transferred operation of their transmission facilities to a Regional Transmission Operator ("RTO")—the Midcontinent Independent System Operator ("MISO") for Vectren South. In 2005, MISO began operating an energy market that has significantly impacted the operation of Vectren South's generation fleet.

Q. Please describe the MISO energy market.

A. The purpose of MISO's energy market is to dispatch the lowest cost generation within the MISO footprint required to maintain system reliability, giving MISO members the lowest cost energy available. As a member of MISO, Vectren South, like all MISO members, projects and submits its hourly energy needs and offers 100% of available generation for each hour of each day throughout the year into this market at the avoided costs. MISO collects all load projections and monetary energy offers and after ensuring the grid reliability is maintained, dispatches the lowest cost generation facilities to meet the projected system needs for each hour of the day. At the beginning of the MISO market, coal-fired generation was often the lowest cost generation in the MISO region and was frequently dispatched. However, falling natural gas prices, efficient gas turbines and the growth of renewable resources have changed how Vectren South's coal-fired generation facilities are operating in MISO.

Q. How have the growth of renewable resources impacted MISO's dispatch?

A. The dispatch of renewable resources has changed the generation stack within MISO. The Production Tax Credit ("PTC") for wind incents operators of these facilities to offer generation into the market at very low to negative prices or designate them as must run resources because the tax credits are earned only if the facilities are operating. The Investment Tax Credit ("ITC") incentivizes the build of solar facilities. Once the capital is invested in solar which has zero fuel costs, they can be offered at very low prices or as must run generation. Of course, these facilities only generate energy whenever the wind or sun allows. This means that wind and solar resources are dispatched before other forms of generation unless curtailment of renewables is necessary to ensure the reliability of the grid. Due to the intermittency of wind and solar, fossil-fuel based resources are left to balance the system when the output of the renewable resources changes (for example when the wind subsides or cloud cover blocks the sun). This impacts the dispatch of Vectren South's coal-fired generation units causing them to cycle up and down throughout the day and increases the frequency of stop and start cycles throughout the year. As mentioned earlier, coal units were designed to run continuously.

The frequent cycling affects unit efficiency and the thermal contraction and expansion of large masses of metal causes wear and tear, increased maintenance and shortens life.

Q. How has the reduction in natural gas costs impacted MISO's dispatch?

A. The dramatic decline in the price of natural gas has enabled newer, highly efficient natural-gas fired generation to operate at a lower cost than coal-fired generation. During periods of low electric demand, highly efficient gas plants are often dispatched by MISO rather than coal-fired generation. Compared to coal fired baseload generation, these units also have the ability to ramp output up and down quickly and are built for more efficient off/on cycling.

Gas combustion turbines also inherently produce fewer regulated air emissions. Vectren South has had to make significant investments in environmental controls to enable its coal-fired facilities to operate within environmental requirements. Vectren South is proud of its environmental record and the fact that its coal fleet is one of the cleanest in the mid-west; 100% controlled for sulfur dioxide ("SO2"), 90% controlled for nitrogen oxide ("NOx"), in compliance with mercury ("Hg") and particulate emission standards and controlled for sulfuric acid ("H2SO4"). Vectren South also recycles fly ash and gypsum by-products for beneficial re-use in cement and wall board manufacturing. However, the operating costs associated with the pollution control systems impose additional operating costs on the coal-fired units as compared to gas-fired generation.

Q. How have these factors impacted Vectren South's coal-fired generation facilities?

A. Together, these factors have made the coal-fired units less competitive, reducing their dispatch rates. The impact varies depending on the age, efficiency and condition of units. For example, our best unit, Culley Unit 3, has a more favorable dispatch rate than the Culley Unit 2 or the Brown units. As reflected in our IRP modeling, these factors will challenge coal units going forward.

Q. You previously mentioned impacts on unit dispatch. Please explain trends in the dispatch of coal units.

A. The output of Vectren South's coal units must constantly be adjusted to follow MISO's instructions, resulting in significant ramping output up and down and cycling the units off and back on. For example, in 2008 our coal fleet had a capacity factor of 75% and a total of 60 unit starts but in 2017 capacity factors dropped to 52% and there were a total of 86 unit starts. Since 2008, unit starts have been as high as 120 (2011). The industry is aware that frequently cycling of coal units off and back on and ramping output up and down has long term negative impacts on the equipment in a coal-fired generation facility. A June 3, 2015 U.S. Department of Energy report on coal-fired generation titled "Impact of Load Following on the Economics of Existing Coal-Fired Power Plant Operations" recognizes 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."[2] A few examples from the report on major coal-generation components and maintenance issues from cycling include:

- **Coal Pulverizer** - Mechanical wear when cycled at low end of minimum flow rates.
- **Superheater Header & Tubes** - Overheating from low/no-flow of cooling steam (startup) and/or poor combustion gas temperature management causes thermal deformation. Internal ligament cracking. Oxidation and exfoliation from exposing metal to higher temperatures than design.
- **Feedwater Heaters** - Early tube failures due to cool-down and rapid heating during hot/warm startup cycle. Tube grooving at the support plates can occur due to poor water chemistry.

[2] U.S. Department of Energy, Office of Fossil Energy, DOE/NETL-2015/1718, Impact of Load Following on the Economics of Existing Coal-Fired Power Plant Operations, p. 7 (2015), available at https://www.eenews.net/assets/2017/11/21/document_gw_08.pdf.

- **Steam Turbine/Generator** - Steam seals may need to be replaced to prevent steam from bypassing rotor stages. Most units have been changed to Brandon packing; primary concern would be exhaust hood temperatures and ability to control the temperature at low steam flows.
- **Admission Valves** - Throttling increases wear and reduces efficiency.
- **Turbine Rotor** - Reducing startup time and increasing the number of annual start cycles can substantially increase rotor material degradation, causing rotor failure. This may result in blade loss, spindle fracture, and even fast fracture from a near-bore causing catastrophic failure.
- **LP Turbine Blades** - Solid particle erosion. Impingement of droplets leads to accelerated damage of erosion shields and blade surfaces. LP last stage blade stall flutter at low flow conditions may cause blade vibration, resulting in cycle fatigue.
- **Generator** - Retaining ring and end-turn fatigue that can lead to failure/arcing. This will only be an issue if a shift from the generator to line voltage of ±20% is required.
- **Steam Piping** - Thermal stress and fatigue cracking due to temperature fluctuations.
- **Flue-Gas Desulfurization ("FGD") Absorber** - Thermal stress and fatigue cracking due to temperature fluctuations.
- **Baghouse** - Wet gas corrosion from operating below acid dew point at low load.
- **FD/ID Fans** - Frequent start/stop of fans increases failure rates, inspection intervals, and motor-fan maintenance.

AB Brown Unit 1 has experienced the effects of cycling first hand as Solid Particle Erosion ("SPE") damaged a turbine by-pass valve allowing foreign particles to enter the turbine causing a three month outage and a $3.8 million repair during the summer of 2016. The issue appears to have occurred in the main steam outlet header where scale appears to have flaked off the internal header due to multiple thermal transitions related to unit cycling. Turbine valves are now being inspected and changed out more frequently to prevent a similar occurrence.

Ramping units up and down also has an impact on efficiency and subsequently the cost to produce power. For example, an A.B. Brown unit operating at low load is approximately 5% less efficient than when at full load which results in an increase in fuel cost on a dollar per megawatt hour ("$/MWHr") basis. Low load operation also increases the FGD chemical cost to remove SO2 from the flue gas by approximately 18%.

Q. Are coal unit challenges unique to Vectren South?

A. No. Analysis of data compiled by SNL (S&P Global) shows 458 coal units constituting over 52 gigawatt ("GW") of capacity have been retired nationwide since 2012 with 97 of those located in the MISO footprint.[3] Another 85 coal unit retirements have already been approved for future retirement in the U.S. with many others announced but not yet approved. These recently approved coal retirements alone will require over 16 GWs of new capacity to replace the lost generation. The majority of this generation is scheduled to be replaced with natural gas fired combined cycle units.

Q. Has Vectren South evaluated the merits of continued reliance on coal-fired generation to serve such a large portion of its customers' needs?

A. Yes. Every three years, Vectren South prepares an Integrated Resource Plan ("IRP"). Our most recent IRP, finalized in 2016 (the "2016 IRP") concluded that the lower operating and maintenance cost and greater efficiency of a CCGT plant provides a lower cost option for our customers over a twenty year period compared to continued operation of our coal fleet. Vectren South witnesses Lind and Rice explain the IRP and the results of the analysis. These results are consistent with Vectren South's observations that the low cost of natural gas and the greater efficiency of a CCGT render construction of a new CCGT more advantageous from a purely economic perspective over a twenty year planning horizon.

Q. Please compare the efficiency of a CCGT to Vectren South's coal units.

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[3] Energy Unit Retirement, S&P Global Market Intelligence, available at https://platform.mi.spglobal.com/interactivex/file.aspx?donotredirectto3=1&id=390185972&keyfileformat=9&reqfrom=snl3&keyproductlinktype=2.

A. The primary measure of the efficiency of an electric generating facility is heat rate. Heat rate is the amount of energy in British thermal units ("Btu") used to generate one kilowatt hour ("kWh") of electricity. Heat rate is expressed in "gross"; the Btu/kWh of total output of the generator (not including electric consumption to operate plant equipment) and "net"; the Btu/kWh of the total output onto the grid (includes electric consumption to operate plant equipment). The lower the heat rate or number of Btu/kWh produced, the more efficient the generating unit. All coal plants and combined cycle plants operate at different heat rates at different outputs. Plants are typically designed to operate at their highest efficiency (lowest heat rate) at highest output and lowest efficiency (highest heat rate) at lowest output. The following table shows the actual net heat rates for each of Vectren South's coal fired units in 2017 and the expected net heat rate of a typical "F" class CCGT.

	2017 Net Unit Heat Rate
A.B. Brown 1	11,576
A.B. Brown 2	11,007
F.B. Culley 2	12,662
F.B. Culley 3	10,549
Warrick 4	10,896
Vectren Coal Fleet	11,001

	Expected 2024 Net Unit Heat Rate
Typical F Class CCGT	≈6,560

Another example of the increased efficiency of a CCGT unit compared to a coal unit is the amount of auxiliary load it takes to operate. The auxiliary load required to operate all of the environmental and other ancillary equipment (pumps, motors, *etc.*) associated with one of the Brown coal units is approximately 20MWs or 7.5% of the gross unit output at full load. The auxiliary load for a typical 2X1 F class CCGT is approximately 18MWs or 2.1% of gross unit output at full load.

II. Proposed CCGT

Q. Is Vectren South proposing to replace a portion of its coal-fired generation with a CCGT as recommended in its IRP?

A. Yes. Consistent with its 2016 IRP results and updated IRP modeling completed in 2017, Vectren South proposes to retire a portion of its current coal fired generation fleet and diversify the generation portfolio by adding a highly efficient base load natural gas CCGT that will provide highly reliable, lower cost generation for years to come.

Q. What are the characteristics of the CCGT Vectren South plans to construct?

A. Vectren South is proposing to build an efficient 2x1 "F" class technology CCGT. The F class CCGT is a proven, highly durable design that has logged numerous operating hours across the power industry. The unit consists of two sets of compressors, natural gas turbines, generators, Heat Recovery Steam Generators ("HRSGs") and one steam driven turbine and generator. Simplistically, air is pulled into each of the two compressors where it is compressed to high pressures, mixed with fuel and ignited. This ignition and combustion moves a hot air fuel mixture through the gas turbines turning the blades which in turn drives a shaft connected to the associated generators producing electricity. The waste heat from each gas turbine enters the two HRSGs. The HRSGs are basically boilers where the waste heat turns purified water into steam. This high pressure steam enters the steam turbine. As the steam flows through the turbine blades, the blades turn a shaft which drives the steam generator producing electricity. This design is very efficient as the waste heat from the gas turbines is used to create more electricity rather than being lost to the atmosphere.

Vectren South has also designed the unit to include gas fired burners within each of the HRSGs. In industry terms, the proposed CCGT is called a "fired" unit because of the gas fired burners. The equipment enabling the firing must be designed and installed at the time the unit is constructed. It offers a very inexpensive investment to obtain additional peaking capacity with some degradation in efficiency. The incremental equipment necessary to enable the firing costs is approximately $15 million but allows the CCGT to produce an additional 150 MWs of output. Stated differently, for an approximately 2% increase in cost, Vectren South can secure a 21% increase in the total output of the CCGT

Q. What advantages will a CCGT provide to Vectren South from an operational standpoint?

A. Given current and projected future market conditions there are several advantages of a CCGT. The unit will provide the flexibility required to allow Vectren South to meet its obligation as a regulated utility to serve our customers in a reliable and cost effective manner. In general, the proposed "F" class unit will have the ability to adjust output quickly. The unit can ramp at a rate of approximately 80 MWs per minute providing the flexibility to meet the changing demand requirements of our customer base as well as the MISO market. This compares to the typical ramp rate of one of the Brown coal units of 3 MWs per minute.

Although not expected to cycle on and off much due to its high efficiency and low operating costs, the unit will have the ability to start up from a cold condition in less than an hour, warm condition in approximately 30 to 40 minutes and a hot condition in less than 30 minutes. This compares to one of the Brown units which requires 18-24 hours for a cold start, 8–12 hours for a warm start and 4-8 hours for a hot start. The CCGT will have a wide range of output as it will be able to operate in a 1x1 configuration (one gas turbine/generator, one HSRG and one steam turbine/generator) producing approximately 180 – 420 MWs or a 2x1 configuration (two gas turbine/generators, two

HSRG's and one steam turbine/generator) producing approximately 380 up 700 MWs and up to 850 net MWs with duct burners in service.

The unit will have lower operating cost due to low long term projected natural gas costs and recent advances in combined cycle technology maximizing the use of British thermal units ("Btu") input making the unit 40% more efficient than the current AB Brown coal plants. When the new CCGT unit comes on line by 2024 it will replace four coal units that will average nearly 50 years in age and four natural gas peaking units, three that will average nearly 55 years in age and one that was retired in 2018 after operating for 39 years. The new CCGT will have mostly new equipment with lower maintenance costs, and less manpower required to operate and maintain as compared to the older fleet that will continue to require capital repairs and higher maintenance costs in order to maintain reliability.

Q. Please show the units and capacity that the new CCGT with an output of approximately 850 MWs will replace.

A. The table below shows that the new CCGT with approximately 850MWs of output will replace 865 MWs of retired capacity. As will be explained later in testimony the exact output of the new CCGT cannot be determined until the actual equipment manufacturer is chosen. This will be completed through a competitive Request for Proposal ("RFP") process at a later date.

Units to be Retired or Exiting	Fuel Source	Year Built	Net Installed MW Capacity
AB Brown Unit 1	Coal	1979	245
AB Brown Unit 2	Coal	1986	245
FB Culley Unit 2	Coal	1966	90
Broadway Ave. Unit 1*	Natural Gas	1971	50
Broadway Ave. Unit 2	Natural Gas	1981	65

Northeast Unit 1	Natural Gas	1963	10
Northeast Unit 2	Natural Gas	1964	10
Warrick Unit 4 (Vectren South to exit Operating Agreement)	Coal	1970	150
Total Installed Generation Capacity (Retiring or Exiting Operating Agreement)			865
*Retired in 2018			

Q. Why build a CCGT unit with an output of approximately 850MWs?

A. As indicated in the table above, this replaces units that Vectren South will no longer have available beyond the 2024/2025 time period. As a public utility with the obligation to serve customers on the peak hour of the peak day of the year Vectren South must hold the capacity to satisfy the MISO Planning Reserve Margin ("PRM") requirements imposed on load serving entities. Holding some additional capacity is important to Vectren South and its customers as this provides Vectren South the opportunity to attract new customer load spreading fixed costs and lowering all customer bills. Southwest Indiana is an attractive site for industrial expansions and relocations due to access to the Ohio River with ports, a robust rail system and nearby access to major highway infrastructure. This results in frequent opportunity for economic development activity.

Q. Does the MISO PRM change from year to year?

A. Yes. Within the past five years, MISO's PRM, based on installed capacity, has swung between 14.3% and 17.1% and has been trending upward. In one year, the Unforced Capacity PRM changed by 30%. The PRM calculation is driven by four factors: external non-firm support, load forecast uncertainty, load, and generation performance. External non-firm support refers to the diversity of load between MISO and neighboring systems and areas outside of MISO that allow for limited support and transfer of capacity through transmission. An example would be generators in PJM providing capacity to MISO load. Load forecast uncertainty exists due to the variability of economics, weather and customer behavior that impact the demand for energy and increases the uncertainty of forecasts. The greater the Load Forecast Uncertainty, the greater the PRM. Finally, generation as it is modeled in terms of capacity and firm imports, impacts the PRM calculation based on the size and outage history of the generators.

Q. What is the estimated cost of the CCGT?

A. The anticipated cost of the CCGT is $781 million (+/-10%). This estimate includes; project study costs, engineering, procurement of material and equipment, construction, owner's costs, project contingency, project escalation, owner's risk contingency and owner's allowance for funds during construction ("AFUDC"). A breakout of these cost estimates is provided in the following table:

Description	GE F.05 (F) 2x1
B&V EPC Estimate (2017$) (includes overhead & profit, contingency & escalation)	$582M
Owner's Cost/Allowance	$40M
Builder's Risk Insurance	$3M
Owner's Contingency	$41M
Study Costs	$14M
AFUDC	$96M
Escalation (owner's allowance and owner's contingency)	$5M
Total Vectren Estimate	**$781M**

I will subsequently provide greater detail about the process utilized by Vectren South to develop the cost estimate of the CCGT.

Q. Has Vectren South selected a manufacturer of the equipment yet?

A. No. Assuming the Commission grants a certificate for the CCGT, Vectren South will commence procurement by seeking to leverage competition among three manufacturers to get the best price. This process will seek the best bids for an "F" class CCGT turbine and associated equipment. The specifications of the unit ultimately chosen may deviate somewhat from the details provided in my testimony because the manufacturers are constantly designing improvements into their latest units. There is an outside possibility that a competitive price could be offered for newer technology in the same output range. This is dependent on technology advances, the demand and plant manufacturing capacity for different technology at the time of the final competitive bidding and the desire of manufacturers to get newer technology into the market place. Vectren South cannot finalize this process until Commission issuance of a certificate because obtaining the best, most up-to-date pricing requires the Company to be in a position to execute contracts to purchase the facilities.

Q. Where is Vectren South proposing to construct the CCGT?

A. The Company is proposing to construct the CCGT on ground it already owns around its Brown generating station.

Q. What are the benefits of constructing on the Brown Site?

A. Building on the Brown Site provides several cost savings for Vectren South customers by re-using the existing facilities and equipment. The Brown site is also close to the Ohio River and has a designated entrance road off a main highway and rail access to the location of the proposed facility. This will allow for large sections of the new plant to be barged to a nearby unloading location and moved by rail or truck into the facility with the option to rail large sections from the manufacturing facility directly to the plant. In addition the Brown Site already has black start capability with a diesel generator configured that will be set up to black start the new CCGT.

The Brown Site is also located within Vectren South's service territory. This ensures that the economic benefits resulting from this investment are enjoyed by Vectren South's customers, as described in more detail by Vectren South witness Dr. Michael J. Hicks.

Q. What facilities is Vectren South reusing at the Brown site for the CCGT?

A. Vectren South has worked with Black & Veatch ("B&V") to design the new CCGT to reuse as much of the current facility and equipment as practical. Examples include the maintenance shop, parts storage warehouse, administrative building, river intake system on the Ohio River for cooling tower make-up water, a well reservoir pumping station to supply potable water, water to the plant fire protection system and demineralized reverse osmosis system for water make-up to the HRSGs, water chemistry treatment systems, laboratory and associated equipment for water analysis, ammonia storage and supply for NOx control, oily waste system and reserve auxiliary transformers. There are also other obvious benefits from building on the existing Brown site such as the property is available with adequate access roads, rail for delivery of large equipment, close proximity to on-site existing 138kv and 345kv switchyards. The site environmental permitting should provide for emissions netting due to retiring an existing coal plant with higher emission limits reducing costs as this opportunity would not be available at a greenfield site.

Q. What benefits accrue to the project by virtue of the reuse of the facilities?

A. There is conservatively an estimated $50 million project cost reduction by reusing the existing site, facilities and equipment on the A B Brown site.

Q. Has Vectren South considered the risk that some of these facilities will fail earlier than building new facilities?

A. Yes. Vectren South has evaluated all of the facilities and equipment intended to be integrated into the new CCGT project. They have all been well maintained and are in good condition. They will obviously require more maintenance in future years and likely fail earlier than if all new facilities and equipment were put in place, however, the upfront capital cost savings compared to the increased future maintenance cost of integrating these assets into the project make financial sense for Vectren South customers.

Q. Does the Brown Site have adequate transmission, water and gas service for the CCGT?

A. The Brown Site does have adequate transmission and water service as a result of the Brown generating facility that is already located at the site. The site contains a 138kV and a 345kV switchyard that directly connects the AB Brown site to the electric grid. The site has a river intake system with three pumps that provide up to 9,900 gallons of water per minute ("GPM") for cooling tower make-up (the proposed CCGT requires approximately 5,400 GPM) and a well reservoir with three pumps that provide up to 6,000 GPM for potable water, fire protection system water, and water for the demineralized reverse osmosis system to provide make-up water to the HSRGs (the proposed CCGT plant requires 2,800 GPM) and other service water requirements. Vectren South completed construction of a 345kV transmission line and switchyard as a MISO Multi Value Reliability Project in 2010 that increases the ability to transmit energy from the AB Brown site into the transmission system. There is currently not sufficient natural gas service at the Brown Site. Based on an evaluation of the CCGT's demand, Vectren South (Gas) plans to construct a 23-mile natural gas lateral to interconnect with Texas Gas Transmission ("TGT") to supply the necessary capacity. Vectren South witnesses Pergola and Hoover describe the gas pipeline Vectren South (Gas) will construct and the capacity that is available from TGT to ensure adequate supplies of natural gas to the CCGT.

Q. Are there other benefits to Vectren South's customers by having the CCGT interconnected with Vectren South's transmission system?

A. Yes. Burns & McDonnell has completed a modeling analysis from a Vectren South perspective on how to best interconnect the CCGT into the existing 138kV substation. The analysis focused on capital upgrades required to make the interconnections as well as long term congestion impacts, line losses and potential transmission upgrades. The analysis concluded Vectren South customers benefitted from interconnecting both gas units as well as the steam generator to the Brown 138KV switchyard. Additionally, the 345kV line running past the Brown facility and the connection between the 138kV and 345kV switchyard located next to each other at the Brown site provides good opportunity for selling low cost energy from the new CCGT into the MISO market benefitting Vectren South's customers through increased wholesale margin and higher unit efficiency from operating at higher output.

Q. What do you mean by long term congestion impacts?

A. Recall that MISO operates an energy market. In that market, Vectren South and other generators are required to offer their energy into the market at the specific generation nodes and then purchase energy at different load nodes. Nodes that are geographically near each other typically have prices that are similar. However, as the distance between the generation and energy nodes increases, there is greater risk for pricing differences caused by insufficient transmission capability. Customers are exposed to these pricing differentials because they are credited for the price received for energy generated at the generator node and charged for energy purchased at the load node to meet their demands. When the price received for energy produced is lower than the cost of the energy purchased, the effect is an increase to the total cost of energy to serve our customers.

Q. What other replacement generation options did Vectren South consider?

A. Vectren South had discussions with other utilities to explore interest in partnering on a CCGT unit. One in particular expressed interested in partnering and using its portion of the unit to make wholesale power sales. The potential partnership ended when the potential partner was not able to sell their share of the unit output.

Vectren South also solicited competitive bids for power through a power purchase agreement or having a third party build and transfer a CCGT unit to Vectren South. Because I led Vectren South's development of its own self-build option, I was not involved in the competitive solicitation. Vectren South witnesses Luttrell and Lind describe the result of that analysis in more detail.

Lastly Vectren South explored some of the newer class "H" and "J" technology offered by Siemens, General Electric and Mitsubishi but in general these options provided more generation than desired.

III. Evaluation Of Impact of CCGT On Existing Generation Fleet

Q. What impact will the CCGT have on Vectren South's existing generation fleet?

A. As I noted above, Vectren South intends to replace most of its existing coal-fired generation fleet as well as four older natural gas peaking units with this CCGT. The IRP modeling we have conducted confirms that reliance on a CCGT is more efficient and economical than continued reliance on some of Vectren South's base load coal fired generation. Vectren South is particularly concerned about continued reliance on its Brown Generation facility and Culley Unit 2.

Q. Are there unique challenges faced by Vectren South's Culley Unit 2 and Brown Generating facilities?

A. Yes. Culley Unit 2 is Vectren South's oldest, smallest and least efficient coal unit. It went into commercial operation in 1966 and will be nearly 60 years old in 2023 when the 2016 IRP calls for its retirement. It only produces 90 MWs and normally runs at a heat rate in the 12,500 – 13,000 range. Although the unit does benefit from environmental controls shared with Culley 3, it is the only unit in the Vectren South fleet not controlled for NOx emissions with Selective Catalytic Reduction ("SCR") technology. When Culley Unit 2 operates it does provide benefit to customers as it is primarily dispatched when demand and market prices are high. This provides lower cost energy to the customer base than can be purchased from MISO or it provides wholesale revenue which also benefits the customer through the Company's sharing mechanism. Due to its high heat rate and market changes discussed earlier, it has averaged just over a 23% capacity factor over the past 5 years making it difficult to justify spending dollars for capital improvements. With that said, to keep this unit reliable through 2036 would require approximately $70 million in capital investment. In summary, Culley Unit 2 is nearing the end of its life cycle and should be retired as scheduled in the preferred plan or sooner if a major capital investment is required to keep it operating reliably.

Brown Units 1 & 2, though the newest coal plants in Vectren South's coal fleet, were built with dual alkali scrubbers used to remove SO_2 emissions. Dual alkali scrubbing has been abandoned by the utility industry in favor of forced oxidation scrubbing technology. Vectren South believes the AB Brown plant has the only dual alkali scrubbers left in any generating facility in the United States. These scrubbers have high operation and maintenance costs, are slow to react compared to forced oxidation scrubbers and create a corrosive environment that impacts other plant equipment and facilities. Over the past

10 years, the Company has spent over $1.3 million annually to reinforce structural steel and other equipment and buildings due to corrosion primarily caused by the Brown scrubbers. The cost for chemical agents consumed in order to adequately operate one of the Brown scrubbers is approximately [redacted] that of the forced oxidation scrubber used at Culley. The AB Brown scrubbers produce a waste known as filter cake. Although there have been several efforts to find a way to beneficially reuse this material, there is no opportunity at this time. When the Brown units are operating, Vectren South employees load dump trucks with the filter cake by-product 24/7. The filter cake is placed in an on-site landfill that requires real estate for annual development and expansion as well as continued maintenance and environmental monitoring. The current landfill is scheduled to run out of space in the mid-2020s timeframe.

Each Brown unit has a separate scrubber that was installed when the plants were built in 1979 and 1986. An independent consultant conducted a condition assessment of the Brown scrubbers and concluded the alkaline scrubbers have an expected life cycle of 30 years. A copy of this report is attached to my testimony as Petitioner's Exhibit No. 4, Attachment WDG-1. They are now beyond that expected useful life. Given their current condition, the consultant recommended retirement of both scrubbers within the next 5-10 years. Brown Unit 1 will be 45 years old and Brown unit 2 will be 38 years old when the 2016 IRP preferred plan has them retiring in 2024. The recommended replacement is one forced oxidation scrubber to remove SO_2 from both units. The estimated capital cost is nearly $340 million.

Along with a new forced oxidation scrubber in order to comply with the Effluent Limitations Guidelines ("ELG") rule, the new scrubber will require a waste water treatment system. The Brown plant would need several million dollars of capital investment to upgrade the dry fly ash system, a new dry bottom ash system and a new lined landfill with a leachate collection system for dry bottom ash, dry fly ash that is not recycled and scrubber by-product to comply with the ELG and CCR rules described by Vectren South witness Retherford. These capital investments are estimated to cost approximately $150 million. In addition the plant will require approximately $225 million in ongoing capital investments to keep the aging units reliable as expected to meet customer needs through 2036.

Q. Based on this assessment, is Vectren South proposing to retire Culley Unit 2 and the Brown Facility once the CCGT is operational?

A. Yes. The Company does not believe it is prudent to make any material capital investment in Culley Unit 2 because of its age. Consequently, a major failure of equipment at Culley Unit 2 might lead Vectren South to permanently shut-down this unit earlier than 2023. The Brown plant would require several hundred million dollars of capital to replace the scrubber, upgrade the dry fly ash system, install a new dry bottom ash system, new lined landfill, landfill leachate system as well as ongoing capital repair to the remainder of the coal units to keep them operating beyond 40 and 50 years of age.

Q. What is the future of Warrick Unit 4?

A. Warrick Unit 4 will continue to operate in the near term. The long term outlook for the unit is uncertain. Initially, Alcoa made the decision to close the Warrick smelter in 2016 at the time of a corporate reorganization due to low import alumina prices. Since alumina prices have recently rebounded, Alcoa has made the decision to reopen 3 of the 5 pot lines in the Warrick smelter by the end of the second quarter of 2018. These pot lines require significant quantities of electricity, making the Warrick 4 unit an important part of the decision. The future of the unit is tied to the industrial site. Alcoa could decide to close the smelter unit in the future if price volatility in the alumina market impairs the facility's profitability, jeopardizing the future of Warrick Unit 4. Therefore, it is difficult to justify investment in the unit or to depend upon it in the long run.

Vectren South recently agreed to continue the Joint Operating Agreement ("JOA") of Warrick Unit 4 with Alcoa through December 31, 2023 which is when further investment in the unit to comply with environmental requirements is expected. The decision to extend the JOA benefits both parties in the near term as Alcoa is in the process of restarting its smelter operation (creating jobs in Southwestern Indiana) and Vectren South needs the generating capacity to meet its PRM requirement. Alcoa has communicated that they need Warrick Unit 4 in order to make re-opening the smelter economical. Vectren South has an obligation to serve its customer base and is required by MISO to hold enough generating capacity with a reserve margin to meet MISO's PRM. Without Warrick 4, Vectren South would have to purchase capacity for the next 5-6 years from a potentially volatile capacity market. With the rapid closure of several coal plants, there is the possibility that capacity will be in demand and sold at a high price in future years.

Q. Is Vectren South proposing to retain any of its coal-fired generation?

A. Yes, Vectren South will maintain its largest most efficient coal plant, Culley Unit 3. This unit contains all the current environmental controls with the latest forced oxidation SO2 scrubbing technology, fabric filter for particulate control, SCR for NOx removal, H2SO4 control and low cost organo sulfide system for reducing Hg emissions.

Q. What is the condition of the FB Culley Unit 3 scrubber?

A. Culley Unit 3 has forced oxidation scrubbing technology which is the preferred SO2 removal technology in the electric generation industry today. It was installed in the mid-

1990s, has been well maintained and is in good condition. The scrubber by-product produced is gypsum, which is currently used in the manufacturing of wall board in both Louisiana and Indiana. Vectren South has contracts in place to provide the gypsum to the wall board manufacturer.

Q. What benefits accrue to Vectren South and its customers by continuing to operate Culley Unit 3?

A. Vectren South, with some incremental investment in Culley Unit 3, will maintain a diverse generating fleet that contains natural gas base load generation, coal fired base load generation, natural gas peaking generation, wind generation, solar generation, battery storage and landfill gas generation. This will allow the coal unit to run as a base load unit as designed while the CCGT has the ability to cycle quickly adapting to intermittent renewable sources added by Vectren South, its customers, and MISO members in the future. Maintaining Culley Unit 3 will help support Indiana's coal economy and local trucking—the lowest cost method of delivering coal to the Culley plant—and allow Vectren South to maintain a generating facility with on-site fuel storage. Continuing to operate Culley Unit 3 will allow Vectren South to maintain generation on both sides of the service territory which is critical to balancing the local electric distribution grid and supplying reliable service while controlling price through managing congestion and line losses. Continued operation will also allow continued depreciation of the plant balances and maintain good paying jobs, while waiting for renewable energy and energy storage to become more affordable.

Q. What incremental investment in Culley Unit 3 is necessary?

A. Vectren South witness Retherford describes the environmental regulations requiring Vectren South to make investments in Culley Unit 3. Specifically, Vectren South will need to invest in improvements or modifications to the dry bottom ash system and the FGD wastewater treatment system.

Q. Please describe in more detail the dry bottom ash system and FGD wastewater treatment system improvements.

A. Vectren South witness Retherford describes the environmental requirements for bottom ash transport water and FGD waste water. As outlined in our NPDES permit which was renewed in April 2017 and amended February 2018, a dry bottom ash transport water system must be installed prior to December 2020, and the FGD waste water system must be upgraded to a chemical-precipitation biological system by February 2021 or a zero liquid discharge ("ZLD") system by December 2023. Vectren South will also need to close the West Ash Pond at Culley as the pond is currently not accepting ash and is inactive. A portion of the pond will be closed by removing ash and consolidating it in a location of the pond which will be closed in place. As space is very constrained at Culley, and a new pond is needed to accept plant water run-off, this method allows for the placement of a new plant pond within the footprint of the portion of the West pond that is closed by removing ash with minimal changes to existing yard drains, coal pile run-off, and other waste water sources.

Q. What is the estimated cost for the dry bottom ash, FGD waste water treatment, west pond closure and new plant run-off pond?

A. The cost is $95 million for these investments. Vectren South witnesses Retherford and Fischer describe the cost estimates and the work in more detail.

Q. Please summarize why it makes sense to make these investments in Culley Unit 3.

A. Insuring a diverse fuel portfolio is important for the long term stability of Vectren South generation. The upgrades described above will allow for the continued operation of

Vectren South's most efficient coal fired unit. Recent environmental regulations require specific treatment technologies be utilized at coal fired units. Vectren South has selected treatment options that will achieve compliance with the current environmental regulations and minimize impact of future water discharge regulations by eliminating ash and FGD waste water discharges entirely. The cost for the Culley Unit 3 related new pond construction, dry bottom ash conversion, and spray dryer evaporator is estimated at $95 million.

Q. Is Vectren South considering other generation additions to its portfolio to best serve customers?

A. Yes. Vectren has already received approval from the Commission to install two 2 MW solar facilities, one of these with a 1MW/4MWHr Battery Energy Storage System ("BESS") and the other in cooperation with the City of Evansville. These are expected to be in operation in the fall of 2018. Vectren South also obtained Commission approval to install solar and a BESS at the Urban Living Research Center, a downtown Evansville housing facility that will serve as a platform for research and development associated with energy efficiency. In addition Vectren South currently plans, as part of the 2016 IRP preferred plan, to request approval for a 50MW utility scale solar field to be in service in 2020. The 50 MW site will be larger than any current solar site in the state of Indiana.

IV. Cost Estimate of the CCGT

Q. Has Vectren South developed a cost estimate for the CCGT?

A. Yes. Vectren South has worked closely with Black & Veatch ("B&V") to develop +/-10% cost estimates based on current market conditions. The total +/-10% estimated cost of the CCGT is approximately $781 million. Vectren South witness Diane Fischer explains in more detail the basis for estimating the costs of the CCGT unit itself, while I will discuss the owner's costs incurred by Vectren South.

Q. What are owner's costs?

A. Owner's costs are all the costs required to bring the contract to commercially viable operation less the Engineering, Procurement and Construction ("EPC") contract cost. I will describe what an EPC contract is later. While the EPC cost estimate prepared by B&V estimates the costs to engage a third party to construct the CCGT, Vectren South will incur other costs associated with construction. For example, we have incurred study costs to get to a position that we can bid the project. We will need risk insurance and will incur costs to oversee construction of the project. We estimate total owner's costs will be $199 million.

Q. Has Vectren South specifically identified the owner's costs it expects to incur?

A. Yes. The costs are as follows:

Description	Costs
Owner's Allowance	$40M
Builder's Risk Insurance	$3M
Owner's Contingency	$41M
Study Costs	$14M
AFUDC	$96M
Escalation	$5M
Total Owner's Costs	**$199M**

Q. Please describe owner's allowance.

A. The owner's costs covers responsibilities and expenses the owner will incur associated with addressing issues, keeping the EPC contractor and subcontractor crews productive and the project moving forward. Examples include: internal and external engineering and project management support teams to oversee the EPC contactor, project permitting and environmental support, site preparation to include developing laydown areas for equipment, parking lots, access roads, relocation, interconnecting and utilities use, trailers, office furniture and equipment and supplies, consumables, communication, Information Technology ("IT") support, legal support, community outreach, employee training, initial start-up expenses, capital spare parts inventory, federal, state and local taxes, and company overheads for administrative and general expenses and other items. Vectren South and B&V have agreed that 6.5%-7.5% of the EPC cost is a reasonable estimate based on previous experience.

Q. What is builder's risk insurance?

A. Builder's risk insurance is the premium cost of a property damage policy to cover a major event resulting in damage during construction. Vectren South obtained a quote for the cost of this insurance.

Q. What is the owner's contingency?

A. Owner's contingency includes cost for risk outside of the EPC contractor's control such as force majeure events, major work scope changes, natural disasters, major labor issues, financing, regulation or code changes, and other factors. B&V advised that 5% - 10% of the EPC estimate is a normal owner's contingency. Vectren South has reserved $41 million or approximately 7.5% of the EPC estimate for owners contingency.

Q. Please describe study costs.

A. The study costs include the costs Vectren South has incurred to design the facility, evaluate other facility options, develop the detailed cost estimate and other similar costs. This category also includes the costs Vectren South incurred to conduct the RFP and to evaluate the bids received in response to that RFP.

Q. What is AFUDC?

A. AFUDC is the cost of funds Vectren South must secure to pay for the costs it incurs on the CCGT project as it is constructed. Vectren South worked with B&V to develop a project schedule and matching cash flow. The cash flow was then used by Vectren South's plant accounting to project AFUDC.

Q. What do you mean by escalation as a cost?

A. The cost estimates are prepared in 2017 dollars. In reality, the project will spread over several years and costs will increase with inflation. Escalation captures the inflation that will be incurred for equipment, material and labor. Vectren South used 1.6% annual escalation that was used in the 2016 IRP. This was based on information obtained from the St. Louis Federal Reserve Bank. B&V was also requested to provide an independent escalation estimate which was in line with Vectren South's 2016 IRP.

Q. Has Vectren South considered how President Trump's decision to impose tariffs on some imported steel and aluminum could impact the cost estimate of the proposed CCGT?

A. The Trump Administration announced these tariffs after Vectren South completed its cost estimates and mere weeks before Vectren South filed its testimony in this proceeding. The Company has not had sufficient time to evaluate how the tariffs might impact the costs of the CCGT or the costs of the alternative options. Canada and Mexico have been exempted from the tariffs and there is lobbying by other nations to obtain exemptions. There is also uncertainty at this time as to whether the tariff applies to finished goods that are shipped into the country. The Company will continue to follow developments with these tariffs and consider the impact on its cost estimates. To the extent this analysis indicates that tariffs will have a material impact on the cost estimates presented by Vectren South, we will update the Commission and the parties about this impact in this proceeding.

V. Project Management

Q. What strategy will Vectren South employ to manage the CCGT Project?

A. Vectren South will use an EPC firm qualified and experienced in these types of projects. Specific sourcing processes and evaluations will be used to select and manage equipment, materials and service providers. Such aspects as experience, breadth of knowledge, creative thinking to understand and meet the challenges of this specific unit, project teamwork and ability to work cooperatively with the owner will be considered. Prices, cost, and risk sharing will be negotiated and defined within a contract structure.

Q. Please explain what you mean by an EPC estimate?

A. EPC stands for Engineering, Procurement and Construction. One company is hired to supply the detailed engineering, procure all the necessary materials and supplies and complete construction of the facility. There are several ways an EPC contract can be negotiated with different levels of involvement by Vectren South but the primary advantage of an EPC contract is that a scope of work is provided and a contract put in place that requires the EPC contractor take responsibility for turning over a completed project that meets the specifications and requirements of the contract on a specific schedule at an agreed upon price. To a large extent, this places risk of cost over-runs on the EPC contractor, although the EPC contract usually has exceptions for factors beyond the contractor's control. This strategy allows Vectren South to bring in experienced personnel, align schedule and financial interests of the EPC contractor and Vectren South and ensure the proper integration and performance of equipment and systems.

Q. What are the advantages to Vectren South's customers of using an EPC contract approach?

A. There is more price and schedule certainty as the EPC contractor is under contract to supply a finished product that meets the specifications and requirements of the contract. The downside is that the contractor usually builds in a higher contingency in the bid to reduce its risk of cost over-runs.

Q. Can the EPC price change during the project?

A. Yes. There is always the possibility of change orders that could increase the final cost. Although the projected price should be close to the final price there may still be things that occur that are out of the EPC contractor's control and result in cost increases being passed on to the owner. Examples include changes in local labor wages, force majeure events, and changes in design requirements for the facility for various reasons.

Q. Will the Company use competitive bidding?

A. Yes. Vectren South will start with procuring an owner's engineer. The owner's engineer will help create specifications for the CCGT unit power island and the EPC contract for competitive bidding. The power island includes the major components of the CCGT. This would be the gas compressors, turbines, generators, HRSGs and steam turbine, condenser and generator. Once the EPC contractor is selected, Vectren South plans to work jointly with the EPC contractor and owner's engineer to further develop unit criteria and specifications as well as cost control ideas and techniques. Vectren South will work closely with the owner's engineer and EPC contractor to evaluate and award the power island and other major equipment. A negotiation process will take into account not only price but performance guarantees and long term service agreements. The same process will be followed for all other major equipment.

Q. Please explain why this method is preferred.

A. Based on good project management practices and experience, getting the EPC contractor involved upfront and working together on final purchasing decisions and design options will create ideas to reduce costs and increase the chances of a successful project with fewer surprises.

Q. How will subcontracting work be handled?

A. Vectren South feels strongly about having a voice in choosing subcontractors and will likely make this a requirement with the EPC contractor. The success of a project of this magnitude and complexity often comes down to the skill, experience and work ethic of the craft assigned. Southwest Indiana is fortunate to have the skilled craft required to complete a project of this nature and Vectren South desires to ensure that the local crafts have a major role in the project. Vectren South has experience with several local contractors, some who have helped us put our cost estimate together, and have confidence they can provide the professional support needed for a successful project. These companies maintain quality craftsmen and we want to ensure they have the opportunity to compete for this work.

VI. Vectren South's Transition to Gas

Q. When does Vectren South anticipate the CCGT will be operational?

A. The current plan is to have the new CCGT unit complete all performance guarantees and be available for commercial operation prior to February 15, 2023 in preparation for the 2023–2024 MISO capacity year. Operational testing is planned to begin in the third quarter of 2022 to identify and resolve potential issues. In order to meet this schedule and allow 36-42 months for procurement of equipment and construction, Vectren South must have approval to order equipment in the late spring to early summer of 2019.

Q. Why is it important that the CCGT become commercially available for the 2023-2024 MISO capacity year?

A. Vectren South has the obligation to hold adequate generating capacity to serve the annual peak demand of our customer base plus a required PRM. In order for the CCGT capacity to qualify for the 2023-2024 capacity planning year it must meet required testing protocol prior to the last business day of May 2023. If the CCGT cannot meet the qualifications by February 15, 2023, Vectren South must submit, in writing to MISO that the required testing will be complete between March 1, 2023 and the last business day of May 2023 or Vectren South will be required to purchase capacity. Due to potential unit retirements, it is uncertain if capacity will be available to purchase and at what cost if it is available. If capacity is not available, based on current MISO rules, Vectren South will need to pay a penalty in the form of Cost of New Entry ("CONE"). CONE is determined annually by MISO which has traditionally been the cost to construct a new natural gas combustion turbine. The 2018-2019 CONE price for MISO zone 6 was set at $89,250 per MW year. At this price purchasing 850 MWs of capacity at CONE would cost over $75 million annually.

Q. Has Vectren South entered the MISO transmission interconnection queue to get MISO approval to interconnect the CCGT to the transmission grid operated by MISO?

A. Yes. Vectren South entered the MISO queue for 847 MWs in the fall of 2016. MISO is nearly complete with the first of three phases of this study. Studies completed by Company consultants indicate no large transmission upgrade costs are expected.

Q. Has Vectren South entered any other generation into the MISO Queue?

A. Yes. The Company has a second project in the MISO interconnection queue that would allow Vectren South to interconnect up to 900 MWs at the Brown site. Conversations with turbine manufacturers have indicated that technology advancements and developments have the potential to increase the output of an "F" class CCGT. CCGT equipment manufacturers are also starting to heavily market their newer "H" class technology. There is always the possibility that when the Company issues its RFP offer for equipment, a more economical option would be the slightly larger unit. The MISO transmission interconnection queue has many projects being studied and long delays in finalization of studies have become the norm, despite MISO's efforts to improve the process. Vectren South has taken steps to ensure that pursuing the most economical unit, if it is larger than 847 MWs, is possible by starting the process of getting MISO approval for interconnection of the larger unit.

Q. Please describe the process to transition from the Brown coal units to the new CCGT.

A. Both Brown coal units 1 and 2 are connected into the 138kV switchyard. The new CCGT will also be connected into the 138kV switchyard. The 138kV switchyard will be configured to transition from the coal units to the natural gas units. During testing of the natural gas units the coal units will be placed in reserve shutdown. Once testing is complete the coal units could be placed back in service if necessary.

Q. Has Vectren South considered the impact to its employees at Brown?

A. Yes. There have traditionally been approximately 105 full time Vectren South employees at the Brown generating plant. We anticipate that it will require 35 employees to operate the new CCGT. Recently Vectren South has let the Brown workforce attrite to 92 employees through retirements and separations. By 2024 there will be another 20 Brown employees and 36 Culley employees eligible to retire. Vectren South plans to examine each position that retires or separates and look for other means to complete work and keep the Brown units reliable for our customers. This will likely involve using outside contractors to perform some functions and will require some cooperation from the union (IBEW Local 702) currently representing Vectren South hourly employees in the power plants to avoid grievances and arbitrations. There may be positions, for various reasons, that Vectren South chooses to hire. One of the challenges the Company will face near initiation of commercial operation of the new CCGT is adequately training employees while still operating the coal units.

Ultimately, our goal is to find a position within the Company for all Vectren South employees impacted by the transition and have no lay-offs. We are fortunate that our power plant employees have great skills that can be transferred to the Energy Delivery side of our business. As openings become available in Energy Delivery, we will evaluate the opportunity to delay direct hiring to provide positions for qualified power plant personnel.

Q. Will Vectren South continue operating the Brown coal-fired facilities once the CCGT comes on-line?

A. No. Once CCGT has met its performance guarantees and is released for full commercial operation, the Brown coal units will be retired.

Q. When will FB Culley Unit 2 be retired?

A. The current plan is to continue offering FB Culley Unit 2 into the MISO market through December 31, 2023 because the unit will require renewal of its NPDES permit on January 1, 2024. This extension is expected to result in tightening of water discharge limitations that will require further capital investments in the unit.

Q. When will Vectren South exit the operating agreement with Alcoa on Warrick 4?

A. As described earlier the current plan is to exit the JOA on December 31, 2023.

VII. Public Interest

Q. Does Commission approval of Vectren South's proposal serve the public interest?

A. Yes. Vectren South's resource planning demonstrates that its customers are better served, over the long run, by investing in a highly efficient CCGT and retiring Culley Unit 2, Brown Units 1 and 2, and exiting the JOA for Warrick Unit 4. Vectren South cannot continue to operate these coal units without additional capital investments, both for annual maintenance and to comply with environmental requirements. Brown alone is facing nearly $715 million in known capital investments to keep it operating through 2036. Vectren South's modeling demonstrates that replacing these units with a highly-efficient CCGT will result in a generation unit that is better designed to operate with the flexibility necessary in the MISO market and at a lower cost. This unit will better meet the needs of Vectren South's customers and position them for the future.

Vectren South also proposes to maintain its most efficient coal unit, Culley Unit 3. While the modeling demonstrates that the absolute lowest cost results from replacing all coal units with gas-fired generation, Vectren South's customers would become highly dependent on natural gas pricing. Maintaining Culley Unit 3 provides fuel diversity for some portion of Vectren South's load. Investment in Culley Unit 3 will allow it to continue to operate beyond 2023. In addition Vectren South will continue energy efficiency programs, follow through on building two 2MW solar fields, one with a 1MW/4MWHr discharge Battery Energy Storage System already approved by the commission and shortly follow up with a request to construct a 50 MW utility scale solar field which can be used to serve the customer base or designated to industrial and commercial customers with corporate renewable goals. When complete, Vectren South will have a diversified, efficient portfolio that includes base load natural gas, natural gas peaking, base load coal, wind, solar, battery energy storage, and landfill gas while continuing to offer energy efficiency programs.

VIII. Ongoing Commission Review

Q. Please discuss the Company's request for ongoing Commission review.

A. Vectren South proposes that an ongoing review process for the Projects be conducted quarterly. The Company will submit progress reports of construction, updated cost estimates, any revisions to the cost estimates and other information regarding the implementation of the Projects in this Cause. Vectren South understands that there will be a public hearing before the Commission approves any material changes in the cost estimates to reflect items not reflected in the previously approved estimate.

IX. Vectren South MATS Project

Q. Please describe the pollution control improvements that the Commission approved in Cause No. 44446.

A. The Commission approved Vectren South's clean energy project investment in control technology at the AB Brown, FB Culley and Warrick Unit 4 generating stations to meet the requirements of the EPA's Mercury and Air Toxics Standards ("MATS"), to resolve a Notice of Violation ("NOV") issued by the EPA and waste water treatment systems to comply with the National Pollutant Discharge Elimination System ("NPDES") permit provisions.

When most coal plants were looking to inject activated carbon to control Hg emissions, Vectren South explored alternatives and through experimentation discovered that organo-sulfide was a much lower cost solution that captured Hg in the existing scrubbers allowing Vectren South to comply with the MATS rule at all three facilities and continue the beneficial reuse of fly ash in the cement making process.

An agreement was reached with the EPA on H2SO4 limits which allowed Vectren South to reach compliance targets by injecting soda ash directly into the ductwork ahead of the scrubber at Brown and hydrated lime ahead of the scrubber at Culley. Warrick 4 had previously been required to control H2SO4 emissions and had already installed a hydrated lime injection system.

A physical chemistry treatment system was installed at the Brown and Culley facilities that introduced organo-sulfides, coagulants, and flocculants into the waste water streams to ensure compliance with the newly issued NPDES permits.

Q. What did Vectren South estimate these improvements would cost?

A. The cost estimate presented in Cause No. 44446 was $89.3 million.

Q. What costs did Vectren South ultimately incur to construct these projects?

A. Vectren South managed construction of the improvements carefully and efficiently and was able to construct the facilities necessary to meet compliance requirements for $67,286,412 million, or approximately $21 million less than the cost estimated approved by the Commission.

Q. Do you believe these investments were the right decision?

A. Yes. Vectren South could not have continued to operate the Brown, Culley or Warrick facilities without these investments. The Company evaluated several alternative technologies for complying with each of the requirements and identified the lowest cost solutions. Retiring these units and replacing them with new base load capacity as well as purchasing market capacity was also evaluated. A 10 year Net Present Value ("NPV") analysis demonstrated that investing in these controls and allowing time for the previous environmental control investments plant balances to continue to be reduced by depreciation as well as provide more time to obtain more clarity regarding future environmental regulations and natural gas prices (which were projected to be significantly higher than today) was the best option. The decision also allowed Vectren South to meet contractual commitments for supplying fly ash and gypsum to customers for beneficial reuse in cement and wall board manufacturing and avoided MISO penalties that might have been imposed if Vectren South had fallen below its PRM requirement. These investments have achieved these goals, allowing Vectren South's existing coal units to continue operating through 2023.

X. Conclusion

Q. Does this conclude your prepared direct testimony?

A. Yes, at this time.

VERIFICATION

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

Wayne D. Games

Wayne D. Games

A.B. Brown FGD Condition Assessment & Retrofit Cost Estimate

Vectren Corporation

Vectren A.B. Brown FGD Condition Assessment & Retrofit Cost Estimate
Project No. 98818

Revision 1
7/8/2017

A.B. Brown FGD Condition Assessment & Retrofit Cost Estimate

prepared for

Vectren Corporation
Vectren A.B. Brown FGD Condition Assessment & Retrofit Cost Estimate
Evansville, IN

Project No. 98818

Revision 1
7/8/2017

prepared by

Burns & McDonnell Engineering Company, Inc.
Chicago, IL

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
ABB	A.B. Brown Generating Station
AFUDC	Allowance for funds used during construction
BACT	Best Available Control Technology
BMcD	Burns & McDonnell Engineering Company, Inc.
BOP	Balance of plant
FGD	Flue gas desulfurization
IRP	Integrated Resource Plan
LSFO	Limestone forced-oxidation
NAAQS	National Ambient Air Quality Standards
O&M	Operation and maintenance
PFD	Process flow diagram
PM	Particulate matter
PSD	Prevention of Significant Deterioration
SBS	Sodium bisulfite
SCR	Selective catalytic reduction
SER	Significant Emission Rate
tpy	Tons per year

1.0 EXECUTIVE SUMMARY

Vectren has retained Burns & McDonnell Engineering Company, Inc. (BMcD) to conduct a condition assessment of the existing flue gas desulfurization (FGD) system scrubbers for the two coal units at the A.B. Brown Generating Station (ABB). As part of this condition assessment, BMcD was tasked with identifying the remaining useful life of the existing scrubbers and to develop a screening level estimate of the cost to replace the existing scrubbers with new scrubbers that meet current emissions regulations and allow for potential new more restrictive emission limits. This sectional report (the "Report") has been prepared to present the major findings of the condition assessment. The Report also describes the results and assumptions of the scrubber replacement cost estimate, as well as a high-level assessment of the environmental permitting impacts of replacing the existing scrubbers.

1.1 Remaining Life Assessment

BMcD performed a condition assessment of the scrubbers of ABB's Units 1 and 2, consisting of a document review with on-site visual observations and plant personnel interviews. BMcD was not able to inspect the inside of the absorber modules, tanks or ductwork during this assessment. BMcD previous experience with ABB and the Unit 1 and Unit 2 scrubbers served as a starting point for this effort. BMcD also obtained from Vectren additional information specific to the plant, including equipment condition reports and design documents. A list of documentation collected and reviewed is included in Appendix A.

BMcD visited the site on April 14, 2017 to meet with and interview key plant personnel, and to walk down the plant. During the meeting, Burns & McDonnell described what it previously knew abouth the condition of the plant and any differences were discussed with the attending plant personnel. During the plant walk down, BMcD took photos, which are included in Appendix B.

The scrubbers at ABB Units 1 and 2 use dual-alkali wet scrubber technology utilizing soda ash and lime. The scrubbers were originally supplied by FMC in 1979 and 1986 respectively. The scrubbers therefore have been operating for longer than the typical power plant equipment target design life of 30 years. FMC, which was the principal supplier of the technology, closed in 1988 and no dual-alkali systems have been built since. The dual-alkali process has the advantage that it operates with lower liquid/gas ratios because the absorption step uses a soluble alkali. However, it produces a high sodium content sludge that must be disposed after dewatering in a landfill.

As previously noted, the scrubbers were built around 1980 and have been operating longer than the typical 30-year design life. The operating life of the scrubbers has been impacted by a combination of acidic and caustic environments engendered by mist fallout from the stack and from various inevitable leaks, conditions that are very damaging to both structural steel and concrete. Vectren has been performing continuous replacement, patching, and maintenance over the years. Despite this repair and maintenance, many steel elements and foundations are in precarious shape, as documented in Section 3.2 of this Report. The life limiting structures are most likely the absorbers, which are at some risk of at least partial vessel collapse due to low overturning resistance, although there are problems with structural steel corrosion in many areas, and with the condition of the thickeners and dewatering systems, too. Collapse of a scrubber could happen under its own weight as deterioration continues, or could be brought on by an external factor such as a high wind event. If a scrubber were to collapse, it would be very expensive to restore and would take the corresponding unit out of service for several months at least.

In summary, due to the nature of the technology and the specific conditions observed at the plant, it is our assessment that it would be prudent for Vectren to plan for retirement and/or replacement at a total life of 40 to 45 years maximum (ten to fifteen years longer than typical design life), which implies the scrubbers should be retired and/or replaced sometime over the next five to ten years. Vectren has indicated that they plan to continue remediation in order to maintain usable life of the absorbers until planned retirement in 2023.

1.2 Replacement Cost Estimate

The FGD technology evaluated as a replacement for the existing FGD system at A.B. Brown is the wet limestone, forced-oxidation (LSFO) technology. This technology uses limestone ($CaCO_3$) to remove sulfur dioxide (SO_2) from the flue gas. In the process, excess oxidation air is added to the absorber reaction tank to create a gypsum ($CaSO_4 \bullet 2H_2O$) byproduct.

The wet LSFO technology is an FGD technology that is commonly used to achieve high SO_2 removal rates on coal-fired boilers burning high-sulfur coal. It is available from several suppliers and has a long track record of high SO_2 removal rates. The LSFO technology is also reliable with low frequency of outages caused by the scrubber system.

Budgetary quotes for a new wet LSFO FGD system were requested from seven FGD system suppliers: Amec Foster Wheeler, Andritz, Babcock & Wilcox, Babcock Power, GE Power, Marsulex and Mitsubishi Hitachi. The quotes provided by the system suppliers were averaged and included in the overall capital cost estimate.

The capital cost estimate for the replacement FGD system is summarized in Table 1-1. The total direct cost listed includes the absorber, limestone preparation equipment, and gypsum dewatering equipment included in the budgetary quotations received from various FGD system suppliers. BMcD developed an estimate of the balance of plant (BOP) costs based on costs from past projects.

Table 1-1: Capital Cost Estimate Summary

Area	Cost
Total Direct Cost	$187,700,000
Indirect Cost	$23,000,000
Owner Costs	$28,600,000
Contingency	$59,800,000
Total Project Cost	$299,100,000

A high-level environmental evaluation was conducted to determine the potential air permitting requirements applicable to a scrubber replacement project. An important air permitting issue for this scrubber replacement project will be the potential for Prevention of Significant Deterioration (PSD) review. If PSD is triggered for any pollutant, then a Best Available Control Technology (BACT) analysis is required for all new project sources for pollutants that are subject to PSD. In addition, air dispersion modeling is required for PSD pollutants to show compliance with the National Ambient Air Quality Standards (NAAQS) and PSD Increments (Class I and Class II). Based on the preliminary emissions analyses for the scrubber replacement project, a minor source (state) air permit may be required to permit the new installation of the new emission sources required for the wet scrubbers. It is unlikely that a major PSD air permit would be required, therefore no BACT analysis or air dispersion modeling is required by federal requirements. A good assumption for the timeframe to obtain a state air construction permit for the project would be approximately 6 to 9 months.

1.3 Limitations and Qualifications

Estimates and projections prepared by BMcD relating to performance, construction costs, and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. BMcD has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor’s procedures and methods, unavoidable delays, construction contractor’s method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections. Actual rates, costs, performance, schedules, etc., may vary from the data provided.

2.0 INTRODUCTION

2.1 Background

The A. B. Brown Generating Station is a four-unit, 650 MW power generating facility located on the northern bank of the Ohio river in Posey County, Indiana, 5 miles southwest of Evansville. Units 1 and 2 are coal-fired each with a nominal capacity of 265 MW, while Units 3 and 4 are gas turbines. Bituminous coal with dry sulfur content around 3.5% is used as the primary fuel for Units 1 and 2. In 1979, Unit 1 initiated operation with a dual-alkali scrubber to help reduce sulfur dioxide emissions. In 1986 Unit 2 was completed also with a dual-alkali scrubber, both of which scrubbers are still in operation. From 2001 to 2005, Vectren installed selective catalytic reduction (SCR) devices on four of the five coal-fired units, to reduce nitrogen oxide emissions. In 2004, Vectren replaced an existing electrostatic precipitator at Unit 1 with a fabric filter. Sodium bisulfite (SBS) solution injection before the SCR was added in 2014 to remove SO_3 and enhance mercury removal.

Vectren retained Burns & McDonnell to conduct a condition and remaining life assessment of the existing FGD system scrubbers for the Units 1 and 2, and to develop a screening level FEP-1 (±50%) estimate of the cost to replace the existing scrubbers with new scrubbers that meet current emissions regulations. For the new scrubbers, Burns & McDonnell performed a high level assessment of the potential environmental permitting impacts of the replacement. The life assessment is presented in Section 3.0, and the replacement costs are presented in Section 4.0.

2.2 Existing Scrubber Technology

The scrubbers at ABB Units 1 and 2 use dual-alkali wet scrubber technology utilizing soda ash and lime. FMC, which was the principal supplier of the technology, terminated operations in 1988, and no dual-alkali systems have been built since.

In a dual-alkali process, a soda ash solution is sprayed into an open countercurrent spray tower (the absorber) to remove SO_2 from the flue gas, and lime is added to the product solution in an external tank to recover the sodium solution. The absorbers at ABB use a disc and donut baffle arrangement to enhance interaction between SO_2 and the alkali solution. The main advantage of the dual-alkali process is that lower liquid/gas ratios can be used compared with those in other wet scrubber technologies, because the absorption step uses a soluble alkali and therefore the dissolution rate of the reagent is not the rate limiting step in the process. Its major disadvantage though is that it produces a $CaSO_3$/$CaSO_4$ sludge that must be placed after dewatering in a landfill, because of sodium scrubbing solution losses to the product material and the resulting significant sodium salt concentration in the filter cake. Vectren operates such a landfill adjacent to the plant. Other technologies on the other hand produce byproducts that can be disposed of at low or sometimes negative costs.

2.3 Replacement Scrubber Technologies

The FGD technology evaluated as a replacement for the existing FGD system at A.B. Brown is the wet LSFO technology. The wet LSFO technology is an FGD technology that is commonly used to achieve high SO_2 removal rates on coal-fired boilers burning high-sulfur coal. It is available from several suppliers and has a long track record of high SO_2 removal rates. This technology uses limestone ($CaCO_3$) to remove sulfur dioxide (SO_2) from the flue gas. In the process, excess oxidation air is added to the absorber reaction tank to create a gypsum ($CaSO_4 \bullet 2H_2O$) byproduct.

The wet LSFO technology that was evaluated in this study consists of two absorber towers (one per unit). This study assumed that a single limestone preparation system and single gypsum dewatering system would be shared by both units. In order to minimize unit outage time, this evaluation assumes that the new absorber for Unit 1 would be built to the north of the unit. A new stack would be constructed for Unit 1. The Unit 1 thickener would then be demolished, and the new absorber for Unit 2 would be built in that location. The outlet from the new Unit 2 absorber would then tie into the original Unit 1 stack.

3.0 REMAINING LIFE ASSESSMENT

3.1 Approach and Methodology

Burns & McDonnell conducted a high-level condition assessment and interviewed operation and maintenance staff to determine the current condition of the scrubbers. Additional information was obtained from Vectren during this study, including equipment condition reports and design documents. A list of documentation collected and reviewed is included in Appendix A.

BMcD visited the site on April 14, 2017 to meet with and interview key plant personnel, and to walk down the plant. Observations gathered during the meeting and walkdown are discussed below. Photos taken during the visual condition assessment are included in Appendix B.

3.2 Observations

3.2.1 Overall Scrubber Condition

The operating life of the scrubbers has been impacted by a combination of acidic and caustic environments engendered by mist fallout from the stack and from various inevitable leaks, conditions that are very damaging to both structural steel and concrete. Vectren has been performing continuous replacement, patching, and maintenance over the years, and are presently spending $600,000 per year for maintenance costs and $1,500,000 per year in capital costs to make interventions as they become necessary. Despite this continuous repair and maintenance efforts, many steel elements and foundations exhibit severe corrosion. It must be noted that there are no significant differences in general fitness between the scrubbers of the two units, although there are notable variations from unit to unit in particular cases.

3.2.2 High Corrosion Risk Equipment

The equipment with the most corrosive environment are the absorber towers including inlet and outlet ductwork, and then the thickeners.

3.2.2.1 Absorbers

Absorbers typically have the shortest remaining life due to high rates of corrosion. Although repairs have occurred over the years as documented in Appendix A, and Vectren continues to work diligently to keep the scrubbers operating, significant issues still remain, with two of particular significance. The first is the extensive base flange corrosion, as shown in photos 2, 10, 46, and 47 of Appendix B. The main risk this poses is that the structure may come unmoored due to high winds in severe weather events. The second significant issue is diminished structural integrity of the vessel themselves due to extensive patching, which is documented in the Scrubber Conditions Reports (Item 9 in Appendix A). This manifests itself under the coating by causing bowing of the tower skin under the unbalanced stresses that are left by the patching. In fact, during the visual condition assessment a new instance of bowing was observed as shown in photos 15 and 16. This poses some risk of partial or even total collapse of the structure due to buckling, if the unbalanced stresses become too high.

3.2.2.2 Ductwork and Supports

Some improvements appear to have been made to the ductwork and supports, some support steel and ducts having been replaced due also in part to a fire that occurred in 2015. However, there are leaks and corrosion in many places, as shown in photos 5, 6, 7, 8, 9, 12, and 13. There is significant risk that additional internal stresses on the structures due to build-up of solids or external stresses from extreme weather could still cause structural failure, which would require long outages to repair.

3.2.2.3 Thickeners

Vectren reported that for both thickeners corrosion of the weir and launder, and of the platform and bridge, corrosion and degradation of the base, and also of the wall itself are present and significant (see also photos 27, 28, 29, 30, 31, 32, 33, 40, and 41).

3.2.3 Other Equipment

Other equipment included in the scrubber systems are lime silos, soda ash tanks, lime reactors, recycle system, and lime feed system. The Unit 2 lime mixing tank and its foundation are currently being repaired (see photo 38), and so is the Unit 2 belt filter building wall that separates it from the truck bay. The remaining equipment shows signs of wear and surface corrosion, but in general should be able to continue to operate with regular maintenance.

3.3 Conclusions

The scrubbers were originally designed by FMC in 1978 for Unit 1 and 1983 for Unit 2, and have been operating since 1979 and 1986 respectively. The scrubbers have been operating for longer than the design life of 30 years, with their current life at 31 years for Unit 2 and 38 years for Unit 1.

The life limiting structures are most likely the absorbers, which are at some risk of at least partial vessel collapse due to low overturning resistance. Collapse of a scrubber could happen under its own weight as deterioration continues, or could be brought on by an external factor such as very high winds. If a scrubber were to fail in such a way, the unit would have to be taken out of service for several months (at a minimum) for repairs. There are also significant issues with structural steel corrosion in the ductwork and thickeners.

BMcD concludes that although the high-risk scrubber equipment is currently operational, its continuing deterioration will increase over time its risk of failure with consequent major disruption to plant operations. It is unknown when failure may occur, but given the scrubbers’ current condition and rate of deterioration, BMcD recommends that the scrubbers be retired from service or alternatively replaced before their total life reaches 40 to maximum 45 years. Unit 1 will reach 40 years in 2019 and 45 years in 2024; Unit 2 will reach 40 years in 2026 and 45 years in 2031.

4.0 REPLACEMENT COST ESTIMATE

4.1 Replacement Selection

During the kick-off meeting BMcD and Vectren agreed that the FGD technology that the wet LSFO technology would be considered as a replacement for the current FGD system at A.B. Brown. The wet FGD technology uses limestone ($CaCO_3$) to remove sulfur dioxide (SO_2) from the flue gas. In the process, excess oxidation air is added to the absorber reaction tank to create a gypsum ($CaSO_4 \bullet 2H_2O$) byproduct.

The wet LSFO technology is available from several suppliers and has a long track record of high SO_2 removal rates. The LSFO technology is also reliable with low frequency of outages caused by the scrubber system. The gypsum is a byproduct that can be dewatered relatively easily, so it can be handled and disposed of in a dry state. The wet technology also has the benefit of removing mercury in the oxidized form, especially for boilers firing bituminous coal that use selective catalytic reduction (SCR) systems.

The wet LSFO technology is an FGD technology that is commonly used to achieve high SO_2 removal rates on coal-fired boilers burning high-sulfur coal. In recent years, other FGD technologies have been developed and gained more operating experience. Dry FGD technologies have recently gained experience achieving high levels of SO_2 removal. However, these systems use lime (CaO) as a reagent, which increases operating and maintenance (O&M) costs. Based on the historic performance of the wet LSFO technology in achieving high levels of SO_2 removal at units burning high-sulfur coals, this technology was assumed for the replacement for the dual-alkali systems at A.B. Brown Units 1 and 2.

Further evaluation between the various FGD technologies would have to be done in a more detailed analysis than the scope of this study. The technology selected is a representative technology solution to the scrubber replacement at ABB.

4.2 Description of Replacement

The wet LSFO technology evaluated in this study consists of two absorber towers (one per unit). This study assumes that a single limestone preparation system and single gypsum dewatering system would be shared by both units. In order to minimize unit outage time, this evaluation assumes that the new absorber for Unit 1 would be built to the north of the unit. A new stack would be constructed for Unit 1. The Unit 1 thickener would be demolished, and the new absorber for Unit 2 would be built in that location. The outlet from the new Unit 2 absorber would then tie into the original Unit 1 stack. A general arrangement drawing of the new absorber layout has been provided in Appendix E.

In order to minimize the amount of absorber bleed, the Unit 1 and 2 absorbers are assumed to be constructed of flake-glass lined carbon steel, which can handle high chloride levels. The absorber inlet (interface of wet and dry fluegas) and outlet ducts would be constructed of C276 (hastealloy) as this environment is very corrosive. Each absorber would include the following:

- Slurry recycle pumps, piping and spray headers
- Mist eliminators and a mist eliminator wash water tank and associated pumps
- Absorber bleed pumps
- Oxidation air blowers and injection lances
- Process water tank
- Piping, valves and instrumentation

The limestone storage and handling system to be shared by the new Unit 1 and 2 FGD systems would consist of a truck unloading system, a limestone bulk storage pile, a reclaim conveyor, and two limestone day bins with weigh feeders. The shared limestone preparation system would consist of two ball mills, a mill product tank, mill product pumps, a ball mill slurry classifier, a limestone slurry storage tank, and limestone feed pumps.

Each unit would have a dedicated primary dewatering system consisting of a hydroclone, hydroclone underflow tank, and hydroclone underflow pumps. The secondary gypsum dewatering system to be shared by the new Unit 1 and 2 FGD systems would consist of a vacuum filter feed tank, filter feed pumps, two rotary drum-type vacuum filters, a reclaim (filtrate) water tank, and reclaim pumps.

A Process Flow Diagram (PFD) for the replacement FGD system is provided in Appendix D.

4.3 Conceptual Design Basis

The design basis for the wet FGD system is shown in Table 4-1. The design coal assumed for this study, based on 2014, 2015 and 2016 coal data provided by Vectren, is provided in Table 4-2.

Table 4-1: Design Basis

Parameter	Unit 1	Unit 2
Gross MW	265	265
Heat Rate (Btu/kWh)	10,500	10,400
Annual Capacity Factor	70%	70%
Excess Air	20%	20%
Air Heater Leakage	5%	5%
Air Heater Outlet Temperature (°F)	325	325
Air Heater Outlet Pressure (in$H_2$0)	-8.0	-8.0
Target SO_2 Removal	≥98%	≥98%
Coal HHV (Btu/lb)	11,143	11,143
Coal sulfur content (%S by weight)	3.75%	3.75%
Inlet SO_2 Loading (lb SO_2/mmBtu)	6.7	6.7
Flue Gas at Scrubber Inlet (lb/hr)	2,898,000	2,870,000
Flue Gas at Scrubber Inlet (afcm)	922,000	913,000
PM limit (lb PM/mmBtu)	0.03	0.03

Table 4-2: Design Coal Analysis

Proximate Analysis (wt%, as rec'd)	
Moisture	11.8
Volatile Matter	35.0
Fixed Carbon	45.0
Ash	8.1
Ultimate Analysis (wt%, as rec'd)	
Moisture	11.8
Carbon	62.8
Hydrogen	4.0
Nitrogen	1.1
Chlorine	0.1
Sulfur	3.8
Ash	8.1
Oxygen	7.7
HHV (Btu/lb)	11,143

4.4 Estimating Methodology

Budgetary quotes for a new wet LSFO FGD system were requested from seven FGD system suppliers: Amec Foster Wheeler, Andritz, Babcock & Wilcox, Babcock Power, GE Power, Marsulex and Mitsubishi Hitachi. Many of these quotes included the cost of the limestone preparation and gypsum dewatering equipment. For quotes that did not include this equipment, budgetary quotes on limestone preparation and gypsum dewatering equipment from other projects was added in. An average of the budgetary quotes provided by the system suppliers was assumed for the FGD supply cost.

Direct costs were factored based on costs from past, similar projects. Indirect costs, including engineering and start-up, were also factored based on past, similar projects.

BMcD developed an estimate of the following balance of plant (BOP) direct costs based:

- Equipment installation
- Civil and foundation work
- New chimney for Unit 1
- Demolition of the Unit 1 thickener
- Concrete
- Steel
- Ductwork and insulation
- Buildings (pump houses, limestone preparation enclosure and gypsum dewatering enclosure)
- Piping outside of the absorber islands
- Electrical
- Instrumentation and controls

4.4.1 Estimate Assumptions

The assumptions below govern the overall approach of the cost estimate:

- All estimates are screening-level in nature, do not reflect guaranteed costs, and are not intended for budgetary purposes.
- Assumed contracting philosophy is a multi-contract approach.
- All information is preliminary and should not be used for construction purposes.
- All capital cost and O&M estimates are stated in 2017 US dollars (USD). Escalation is excluded.
- Fuel and power consumed during construction, startup, and/or testing are included.
- Piling is included under heavily loaded foundations.
- All foundations are new; no re-use of existing foundations.
- Adequate water supply is assumed to be available from existing raw water supplies.
- This estimate assumes that adequate electrical power can be made available from existing 480V supplies for the replacement FGD system. Costs for electrical upgrades are not included.
- This estimate assumes that the integrity of the tie-in points is sufficient.

- This estimate assumes that there are no significant underground utilities that would have to be re-routed.
- Removal of hazardous materials is not included.
- Emissions estimates are based on a preliminary review of BACT requirements and provide a basis for the assumed air pollution control equipment included in the capital and O&M costs.
- No new induced draft (ID) fans or booster fans are included in the capital cost estimate. Vectren advised that the existing ID fans have sufficient capacity to handle the pressure drop through the new FGD system.
- This cost estimate assumes that all bleed water from the absorbers would either leave the system in the gypsum cake or be returned to the absorbers via the reclaim water systems. The materials of construction for the absorber were selected to allow for high chlorides build up in the reaction tanks, and the gypsum is assumed to be dewatered to only 80% solids to allow for this type of operation. No water treatment system for the absorber bleed water is included in this cost estimate. This estimate also excludes any modifications that may be needed to the existing fly ash handling system to allow absorber bleed water to be mixed into and disposed of with the fly ash.

4.5 Project Indirect Costs

The following project indirect costs are included in capital cost estimates:

- Performance testing and CEMS/stack emissions testing
- Pre-operational testing, startup, startup management and calibration
- Construction/startup technical service
- Engineering
- Freight
- Startup spare parts
- Project contingency

4.6 Owner Costs

Allowances for the following Owner’s costs are included in the pricing estimates:

- Project development
- Owner’s operational personnel
- Owner’s project management
- Owner’s engineering
- Owner’s startup engineering and training

- Legal fees
- Permitting/licensing
- Construction power, temporary utilities, startup consumables
- Site security
- Operating spare parts
- Political concessions
- Builder's risk insurance at 0.45% of construction cost.
- Contingency at 25% for high level assessment purposes
- Allowance for Funds Used During Construction (AFUDC) at a rate of 7.81%.

4.7 Cost Estimate Exclusions

The following costs are excluded from all estimates:

- Escalation
- Sales tax
- Property tax and property insurance
- Utility demand costs
- Salvage values

4.7.1 Capital Costs

The FEP-1 capital cost estimate for the replacement FGD system us summarized in Table 4-3. The total direct cost listed includes the absorber, limestone preparation and gypsum dewatering equipment included in the budgetary quotations received from various FGD system suppliers, as well as BOP Direct Costs including material and installation labor.

Table 4-3: Capital Cost Estimate Summary (2017 dollars)

Area	Cost
Total Direct Cost	$187,700,000
Indirect Cost	$23,000,000
Owner Costs	$28,600,000
Contingency	$59,800,000
Total Project Cost	$299,100,000

4.7.2 O&M Costs

The scrubber replacement evaluation included a qualitative estimate of the impact of replacing the FGD systems on O&M costs. The major O&M costs associated with FGD systems include reagent, power, waste disposal, and operating and maintenance labor. The power cost associated with the replacement FGD system is not expected to differ greatly from that of the existing FGD system. The main factor in the power consumption of an FGD system is the pressure drop through the system and its impact on ID fan operations. The pressure drop between the existing FGD system and replacement FGD system is not expected to be significantly different.

Both the existing and replacement FGD systems include FGD byproduct dewatering with the use of vacuum filters. Because both systems will handle the dry byproduct in a similar manner, there is not expected to be a significant difference in waste disposal costs. The volume of gypsum generated by the new Unit 1 and 2 FGD systems combined is estimated to be 301,000 tons/yr, assuming a 70% capacity factor.

The number of operators required to operate the replacement FGD system is expected to be similar to that of the existing FGD system. No significant impact to operating labor cost is expected as a result of replacing the FGD system.

The existing FGD system uses two reagents, lime and soda ash (sodium carbonate, Na_2CO_3). The replacement scrubber will use limestone as a reagent. A detailed evaluation of reagent usage and annual costs was not conducted as part of this evaluation, however, limestone is a less expensive commodity. Annual reagent costs are expected to be lower for the replacement FGD system compared to the existing FGD system. The volume of limestone used in the new Unit 1 and 2 FGD systems is estimated to be 193,400 tons/yr, assuming a 70% capacity factor. Assuming a limestone reagent cost of $63.00/ton (delivered), the annual reagent cost is estimated to be $12,200,000.

Scrubber maintenance costs are significant for the existing FGD system due to corrosion issues discussed previously in Section 3.0. Maintenance labor and material costs are expected to be lower for the replacement FGD system compared to the existing FGD system.

4.8 Permitting Requirements

An important air permitting issue for this scrubber replacement project will be the potential for Prevention of Significant Deterioration (PSD) review. If PSD is triggered for any pollutant, then a Best Available Control Technology (BACT) analysis is required for all new project sources for pollutants that are subject to PSD. In addition, air dispersion modeling is required for PSD pollutants to show compliance with the National Ambient Air Quality Standards (NAAQS) and PSD Increments (Class I and Class II).

PSD emissions netting is a term that refers to the process of considering certain previous and prospective emissions changes at an existing major source to determine if a "net emissions increase" of a pollutant will result from a proposed physical change or change in method of operation. If the net emissions change is less than the Significant Emission Rate (SER) detailed in the PSD regulations, then the modification has "netted out" for that pollutant. Therefore, the pollutant is not subject to PSD review. As such, a BACT analysis and air dispersion modeling is not required for the pollutant, in most cases.

Prior analyses for the A.B. Brown Station reviewed the past actual emissions for the coal-fired boilers. These past actual emissions were used to determine if there could be a net emissions increase of SO_2 due to the project. Based on the prior analysis of the past actual emissions for the two boilers, the two-year period of 2013 to 2014 was identified as having the greatest two-year average emissions for SO_2. These emissions are used as the past actual emissions for SO_2. The net annual emissions increase is calculated as the difference of the future potential annual emissions assuming 8,760 hours of operation per year for each boiler and the past actual annual emissions. In this case, the average annual emissions during the period of 2013 to 2014 was used as the baseline actual emissions. The netting analysis shows that the scrubber replacement project would result in a net reduction of 1,471 tons per year (tpy) of SO_2, as seen in Table 4-4. As there is no emissions increase over the significant emission rate (SER) for SO_2, the requirement for PSD permitting is not triggered. Please note that depending on when the project begins construction, the past actuals emissions available to use may change. This may result in and increase or decrease in the net potential emissions from the project.

Table 4-4: Netting Analysis for SO_2 (Unit 1 and Unit 2)

Baseline Actual Emissions[a] (tons/year)	Future Potential Emissions[b] (tons/year)	Net Emissions Increase (tons/year)	Significant Emission Rate (tons/year)
7,610	6,139	-1,471	40

(a) Two-year average of 2013-2014 actual SO_2 emissions for Unit 1 and Unit 2.
(b) Based on 8,760 hours of operation for Unit 1 and Unit 2, each, and 6.7 lb/MMBtu inlet sulfur as well as 98% control by the new wet scrubbers.

In addition to the potential increase in sulfur emissions from the Project, there is a potential increase in particulate matter (PM) emissions from the addition of limestone used in the wet scrubber and gypsum handling. The total limestone and gypsum rates given above were combined with assumptions based on previous similar projects to estimate potential emissions of PM, PM with a diameter less than 10 micron (PM_{10}), and PM with a diameter less than 2.5 microns ($PM_{2.5}$). It was assumed that there would be particulate emissions from the following sources:

- Limestone Handling
  - Limestone unloading to the limestone pile
  - Limestone reclaim tunnel dust collector
  - Limestone pile wind erosion
  - Limestone pile maintenance
  - Two limestone bin vents
- Gypsum Handling
  - Gypsum stackout
  - Gypsum pile maintenance
  - Gypsum pile wind erosion

Emissions from these sources were estimated using either AP-42 emission factors or current vendor data on emission rates (such as grain loading values for bin vents) as well as expected maximum usage rates for limestone and gypsum production. Conservative assumptions were made for the limestone pile size, gypsum pile size and other various parameters used to determine emissions. These assumptions were based on other wet scrubber air permitting projects performed by BMcD. It was assumed that the limestone and gypsum piles are uncovered and uncontrolled. A wheel loader was assumed to be used for pile maintenance for gypsum handling (loading into trucks for hauling) as well as for limestone pile maintenance. For true PSD permit applicability analyses, fugitive haul road emissions should also be included in the analysis. For this high-level analysis, it was assumed that there would be no change in the current haul routes used for the current scrubbers and therefore no increase in emissions due to the operation of the proposed new wet scrubbers.

The estimated emissions are all well below the SERs for PM, PM_{10}, and $PM_{2.5}$ as shown in Table 4-5.

Table 4-5: Estimated Particulate Emissions from Project

Pollutant	Estimated Emissions (tons/year)	Significant Emission Rate (tons/year)
PM	19.3	25
PM_{10}	7.3	15
$PM_{2.5}$	3.4	10

Based on the preliminary emissions analyses for the Project, it appears that a minor source (state) air permit may be required to permit the new installation of the new emission sources required for the wet scrubbers. This analysis shows that it is unlikely that a major PSD air permit would be required, therefore no BACT analysis or air dispersion modeling is required by federal requirements.

A good assumption for timeframe to obtain a state air construction permit for the project would be approximately 6 to 9 months.

5.0 CONCLUSIONS AND RECOMMENDATIONS

Burns & McDonnell recommends that Vectren consider the information presented in this report when considering the economic viability of prolonged operation of the A.B. Brown units.

The present conditions and continuing deterioration of key scrubber equipment will increase over time its risk of failure with consequent major disruption to plant operations. BMcD recommends that the scrubbers be retired from service or alternatively replaced before their total life reaches 45 years maximum. Vectren has indicated that they intend to continue remediation in order to maintain usable life of the absorbers until planned retirement in 2023.

Burns & McDonnell estimates that new scrubbers will cost an order-of-magnitude of $300 million (in 2017$).

After review, Burns & McDonnell believes it is unlikely that a major PSD air permit would be required and new scrubbers could be permitted in 6 to 9 months. However, should Vectren proceed with a scrubber retrofit project, Burns & McDonnell recommends this be re-evaluated against regulations in place at that time.

APPENDIX A – LIST OF DOCUMENTATION PROVIDED BY VECTREN

1. Capital & O&M Costs
2. Chimney Inspections
3. Coal Data
4. Drawings
    a. General Arrangement
    b. Lime System
    c. SBS Injection System
    d. Scrubber
    e. Soda Ash System
5. Emissions
6. FGD Power and Chemical Usage
7. ID Fan Info
8. Outage Cost Info – 2013
9. Scrubber Condition Reports
10. Scrubber Design Information
11. Service Water Information
12. Site Water Balance

APPENDIX B – SITE VISIT PHOTOS

Photo 1 – Unit 1 North Absorber Tower Foundation

Photo 2 – Unit 1 North Absorber - Close-up of Tower Foundation

Photo 3 – Unit 1 North Absorber - Ladder and Structural Steel

Photo 4 – Unit 1 North Absorber - Footer of Structural Steel

Photo 5 – Unit 1 North Absorber Outlet Duct Supports

Photo 6 – Unit 1 North Absorber - Expansion Joint in Ductwork

Photo 7 – Unit 1 North Absorber - Support Under Ductwork

Photo 8 – Unit 1 North Absorber - Platform

Photo 9 – Unit 1 South Absorber Outlet Duct Structural Steel

Photo 10 – Unit 1 South Absorber Tower Foundation

Photo 11 – Unit 1 South Absorber Tower Coating

Photo 12 – Unit 1 South Absorber - Expansion Joint in Inlet Duct

Photo 13 – Unit 1 South Absorber - Columns and Bollard

Photo 14 – Unit 1 South Absorber Exterior

Photo 15 – Close-up of Unit 1 South Absorber Exterior

Photo 16 – Close-up of Unit 1 South Absorber Tower Band

Photo 17 – Unit 1 South Absorber - Platform

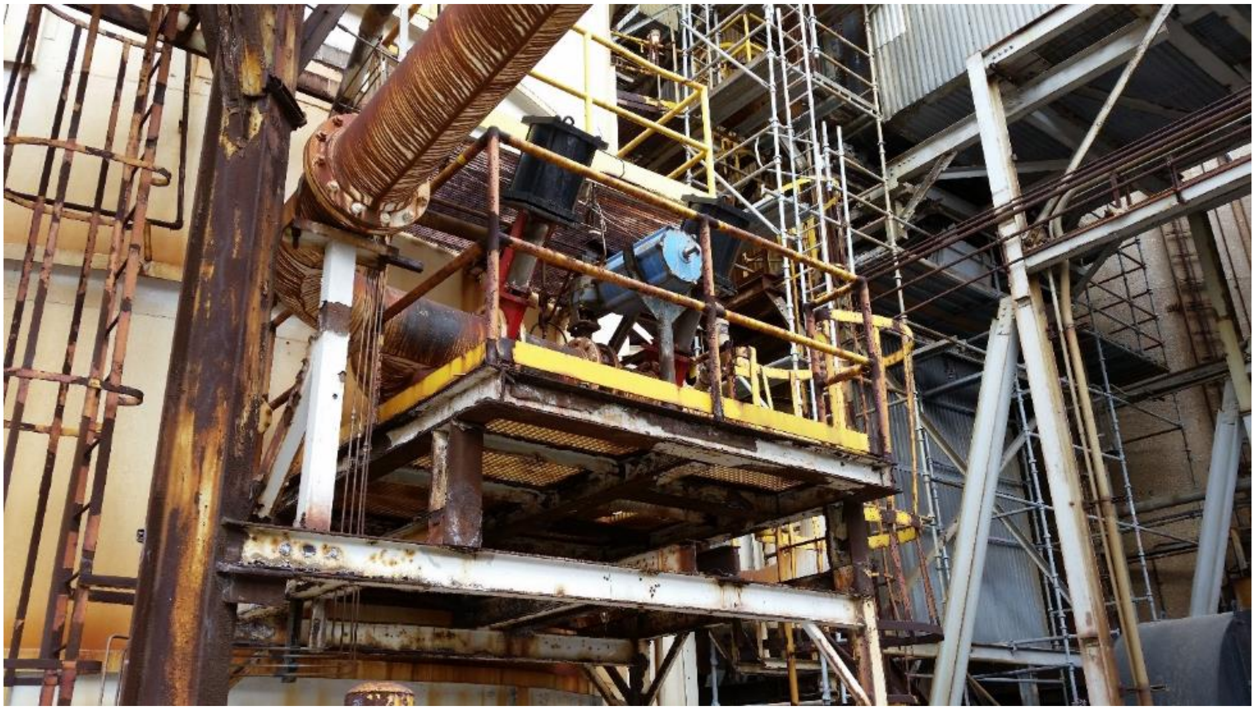


Photo 18 – Unit 1 South Absorber - Pipe Supports

Photo 19 – Unit 1 South Absorber - Close-up of Pipe Supports

Photo 20 – Unit 1 South Absorber - Close-up of Pipe

Photo 21 – Unit 1 Recirculation Pumps Building - Pump Header

Photo 22 – Unit 1 Belt Filter Building - Interior

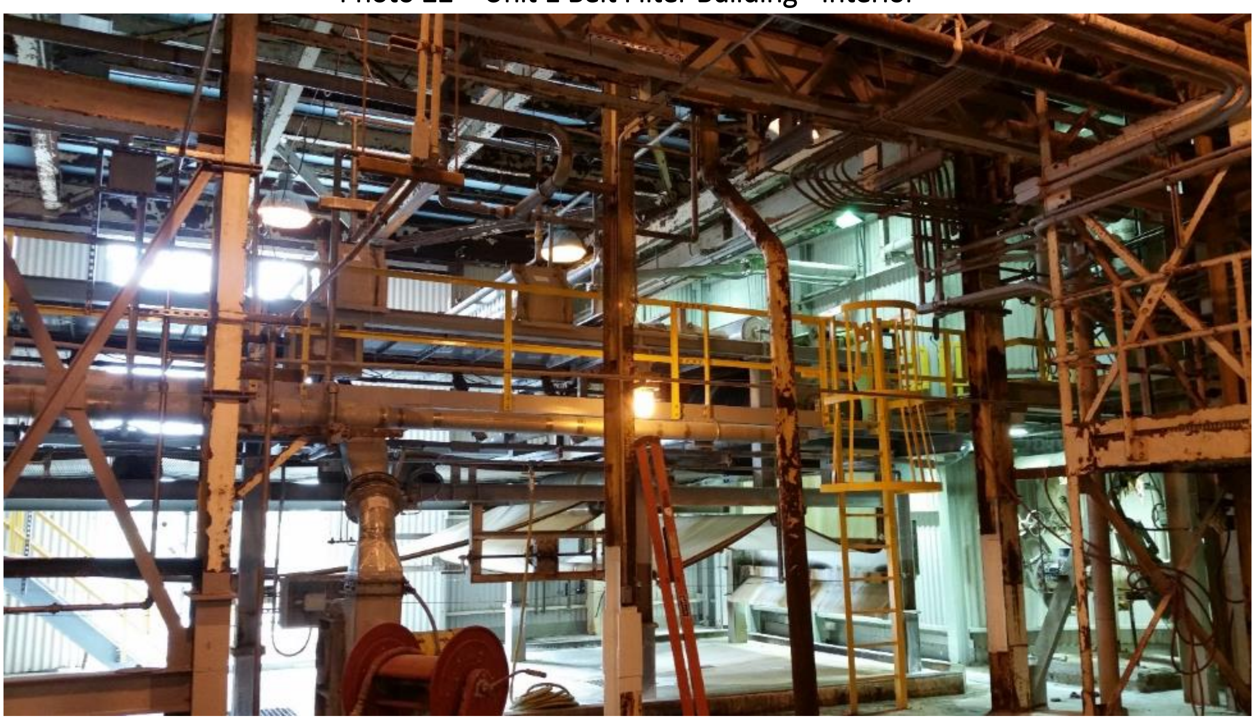


Photo 23 – Unit 1 Belt Filter Building Roof Beams

Photo 24 - Unit 1 Belt Filter Building - Belt Tightener

Photo 25 - Unit 1 Belt Filter Building - Stair and Platform

Photo 26 - Unit 1 Lime Mixing Tank

Photo 27 – Unit 1 Thickener Platform & Bridge

Photo 28 – Unit 1 Thickener - Grating Support Steel

Photo 29 – Unit 1 Thickener - Hand Rails

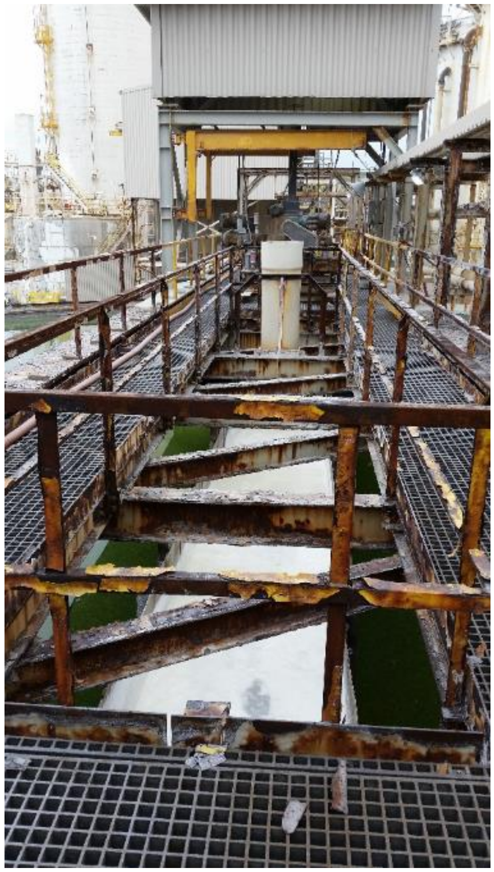


Photo 30 – Unit 1 Thickener - Launder

Photo 31 – Unit 1 Thickener - Launder Close-up

Photo 32 – Unit 1 Thickener - Launder Close-up Showing Color Difference

Photo 33 – Unit 1 Thickener - Drive

Photo 34 – Unit 2 Belt Filter Building - Block Wall

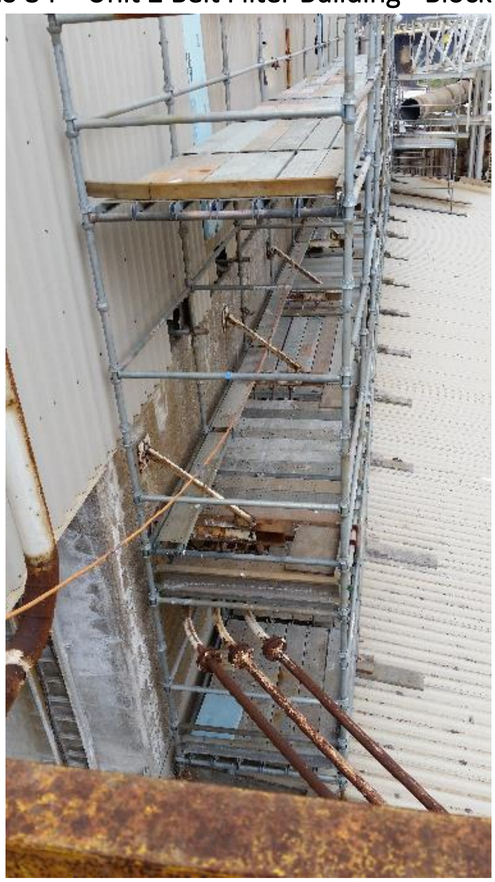


Photo 35 – Unit 1 South Absorber Tower

Photo 36 – Unit 2 Filter Building - Interior

Photo 37 – Unit 2 Filter Building - Interior Close-Up

Photo 38 – Unit 2 Lime Mixing Tank - Foundation Rebuild

Photo 39 – Unit 2 Belt Filter Building - Wall Rebuild

Photo 40 – Unit 2 Thickener - Close-up of Support Steel and Handrail

Photo 41 – Unit 2 Thickener - Launder

Photo 42 – Unit 2 Thickener - Drive

Photo 43 - Unit 2 Thickener - Bottom of Interior

Photo 44 - Unit 2 Thickener - Interior Wall

Photo 45 – Unit 2 South Absorber - Exterior

Photo 46 – Unit 1 North Absorber - Exterior

Photo 47 – Unit 1 North Absorber - Base

Photo 48 - Unit 2 Soda Ash Tank - Base

Photo 49 - Unit 2 Soda Ash Tank - Exterior

Photo 50 - Unit 2 Lime Silo - Exterior

Photo 51 - Unit 2 Lime Silo – Close-up of Piping Penetrations

Photo 52 - Unit 1 Absorber Tower Overview

Photo 53 - Unit 1 Thickener Overview

Photo 54 - Unit 1 Thickener - Contents Close-up

Photo 55 – Unit 2 South Tower Support Structure

Photo 56 – Unit 2 North Tower Support Structure

APPENDIX C – PROCESS FLOW DIAGRAM

no.	date	by	ckd	description
A	5/12/17	KEB	KEB	ISSUED FOR OWNER REVIEW

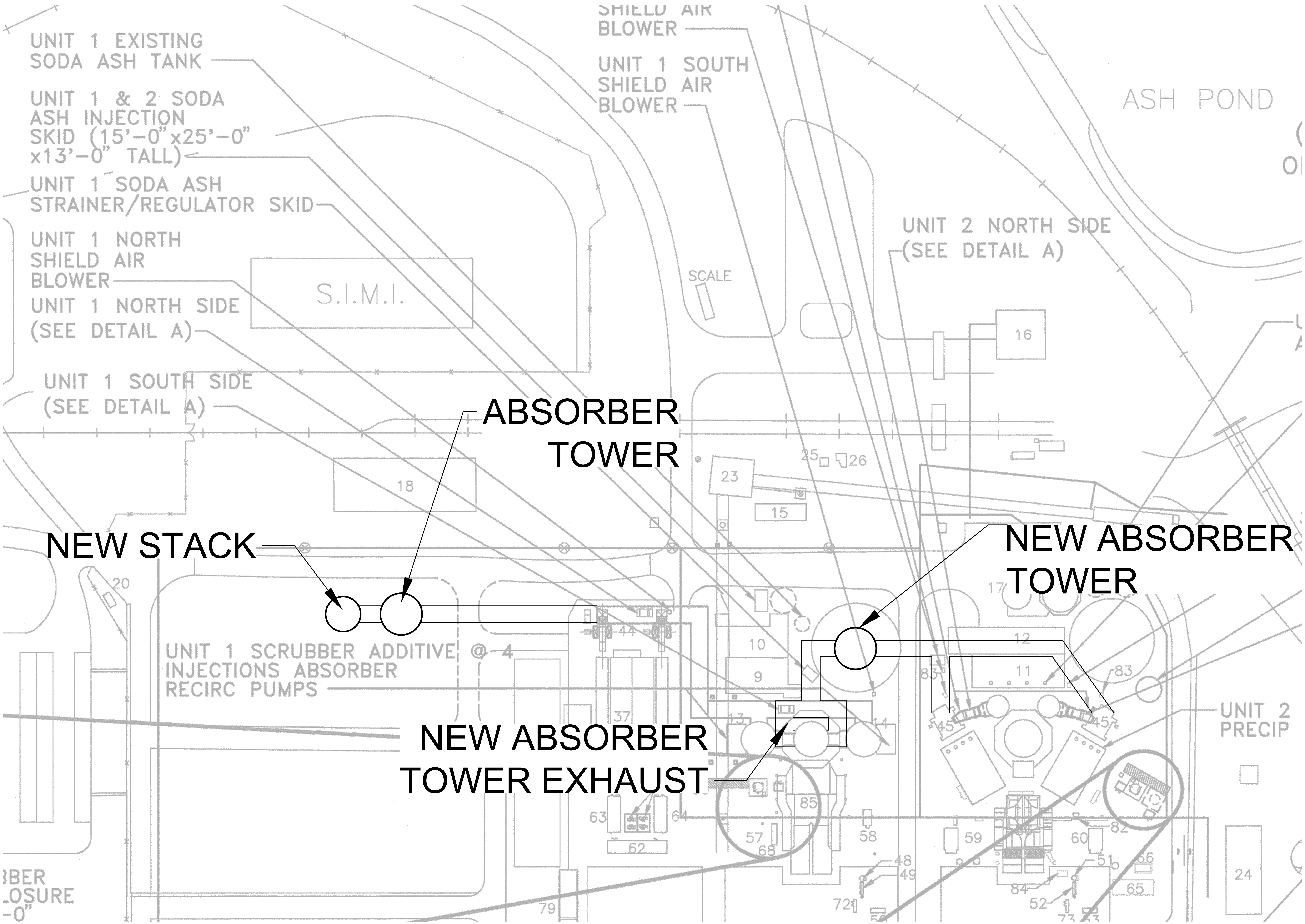
BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: K. BURCHARDT
detailed: R. CHANDLER

VECTREN
VECTREN A.B. BROWN
EVANSVILLE, IN

ABSORBER PROCESS FLOW DIAGRAM
project: 98818
contract:
drawing: PFD001 – rev. A
sheet 1 of 1 sheets
file PFD001.dwg

APPENDIX D – SKETCH OF ASSUMED LAYOUT



no.	date	by	ckd	description
A	5/12/17	KEB	KEB	ISSUED FOR OWNER REVIEW

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: K. BURCHARDT
detailed: R. CHANDLER

VECTREN
EVANSVILLE, IL

SKETCH OF ASSUMED LAYOUT

project: 98818
contract:
drawing: SKM001 –
rev.: A
sheet 1 of 1 sheets
file 98818SKM001.dwg

BURNS McDONNELL

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