Ammonia Scrubber (NH3 FGD)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
O&M - Labor																				
O&M - Scheduled Outage	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,481,658	$ 1,481,658	$ -	$ 1,481,658	$ -	$ 2,963,316	$ -	$ 2,963,316	$ 1,481,658	$ -	$ 2,963,316	$ 1,481,658	$ -	$ 2,963,316
O&M - Base Non-Labor	$ -	$ -	$ -	$ -	$ 246,943	$ 246,943	$ 634,996	$ 634,996	$ 246,943	$ 634,996	$ 246,943	$ 1,269,992	$ 246,943	$ 1,269,992	$ 634,996	$ 246,943	$ 1,269,992	$ 634,996	$ 246,943	$ 1,269,992
Total O&M Costs	$ -	$ -	$ -	$ -	$ 246,943	$ 246,943	$ 2,116,654	$ 2,116,654	$ 246,943	$ 2,116,654	$ 246,943	$ 4,233,308	$ 246,943	$ 4,233,308	$ 2,116,654	$ 246,943	$ 4,233,308	$ 2,116,654	$ 246,943	$ 4,233,308
Capital - Direct Unit					$ 458,608	$ 458,608	$ 2,116,654	$ 2,116,654	$ 458,608	$ 2,116,654	$ 458,608	$ 4,233,308	$ 458,608	$ 4,233,308	$ 2,116,654	$ 458,608	$ 4,233,308	$ 2,116,654	$ 458,608	$ 4,233,308
Capital - Construction	$ 79,223,650	$ 68,296,250	$ 81,955,500	$ 43,709,600	$ 11,650,000															
Total Capital Costs	$ 79,223,650	$ 68,296,250	$ 81,955,500	$ 43,709,600	$ 12,108,608	$ 458,608	$ 2,116,654	$ 2,116,654	$ 458,608	$ 2,116,654	$ 458,608	$ 4,233,308	$ 458,608	$ 4,233,308	$ 2,116,654	$ 458,608	$ 4,233,308	$ 2,116,654	$ 458,608	$ 4,233,308
20 Yr Total	$ 79,223,650	$ 68,296,250	$ 81,955,500	$ 43,709,600	$ 12,355,551	$ 705,551	$ 4,233,308	$ 4,233,308	$ 705,551	$ 4,233,308	$ 705,551	$ 8,466,616	$ 705,551	$ 8,466,616	$ 4,233,308	$ 705,551	$ 8,466,616	$ 4,233,308	$ 705,551	$ 8,466,616

Limestone Forced Oxidation (LSFO)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
O&M - Labor																				
O&M - Scheduled Outage							$2,210,135	$2,210,135		$2,210,135		$4,420,270		$4,420,270	$2,210,135		$4,420,270	$2,210,135		$4,420,270
O&M - Base Non-Labor					$368,356	$368,356	$947,201	$947,201	$368,356	$947,201	$368,356	$1,894,402	$368,356	$1,894,402	$947,201	$368,356	$1,894,402	$947,201	$368,356	$1,894,402
Total O&M Costs	$0	$0	$0	$0	$368,356	$368,356	$3,157,336	$3,157,336	$368,356	$3,157,336	$368,356	$6,314,672	$368,356	$6,314,672	$3,157,336	$368,356	$6,314,672	$3,157,336	$368,356	$6,314,672
Capital - Direct Unit					$684,089	$684,089	$3,157,336	$3,157,336	$684,089	$3,157,336	$684,089	$6,314,672	$684,089	$6,314,672	$3,157,336	$684,089	$6,314,672	$3,157,336	$684,089	$6,314,672
Capital - Construction	$42,487,800	$84,975,600	$169,951,200	$127,463,400																
Total Capital Costs	$42,487,800	$84,975,600	$169,951,200	$127,463,400	$684,089	$684,089	$3,157,336	$3,157,336	$684,089	$3,157,336	$684,089	$6,314,672	$684,089	$6,314,672	$3,157,336	$684,089	$6,314,672	$3,157,336	$684,089	$6,314,672
20 Yr Total	$42,487,800	$84,975,600	$169,951,200	$127,463,400	$1,052,445	$1,052,445	$6,314,672	$6,314,672	$1,052,445	$6,314,672	$1,052,445	$12,629,344	$1,052,445	$12,629,344	$6,314,672	$1,052,445	$12,629,344	$6,314,672	$1,052,445	$12,629,344

Wet Lime Inhibited Oxidation (WLIO FGD)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
O&M - Labor																				
O&M - Scheduled Outage	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,654,587	$ 1,654,587	$ -	$ 1,654,587	$ -	$ 3,309,174	$ -	$ 3,309,174	$ 1,654,587	$ -	$ 3,309,174	$ 1,654,587	$ -	$ 3,309,174
O&M - Base Non-Labor	$ -	$ -	$ -	$ -	$ 275,764	$ 275,764	$ 709,109	$ 709,109	$ 275,764	$ 709,109	$ 275,764	$ 1,418,217	$ 275,764	$ 1,418,217	$ 709,109	$ 275,764	$ 1,418,217	$ 709,109	$ 275,764	$ 1,418,217
Total O&M Costs	$ -	$ -	$ -	$ -	$ 275,764	$ 275,764	$ 2,363,696	$ 2,363,696	$ 275,764	$ 2,363,696	$ 275,764	$ 4,727,391	$ 275,764	$ 4,727,391	$ 2,363,696	$ 275,764	$ 4,727,391	$ 2,363,696	$ 275,764	$ 4,727,391
Capital - Direct Unit					$ 512,134	$ 512,134	$ 2,363,696	$ 2,363,696	$ 512,134	$ 2,363,696	$ 512,134	$ 4,727,391	$ 512,134	$ 4,727,391	$ 2,363,696	$ 512,134	$ 4,727,391	$ 2,363,696	$ 512,134	$ 4,727,391
Capital - Construction	$ 44,892,339	$ 74,820,585	$ 108,832,641	$ 77,883,435	$ 11,650,000															
Total Capital Costs	$ 44,892,339	$ 74,820,585	$ 108,832,641	$ 77,883,435	$ 12,162,134	$ 512,134	$ 2,363,696	$ 2,363,696	$ 512,134	$ 2,363,696	$ 512,134	$ 4,727,391	$ 512,134	$ 4,727,391	$ 2,363,696	$ 512,134	$ 4,727,391	$ 2,363,696	$ 512,134	$ 4,727,391
20 Yr Total	$ 44,892,339	$ 74,820,585	$ 108,832,641	$ 77,883,435	$ 12,437,899	$ 787,899	$ 4,727,391	$ 4,727,391	$ 787,899	$ 4,727,391	$ 787,899	$ 9,454,782	$ 787,899	$ 9,454,782	$ 4,727,391	$ 787,899	$ 9,454,782	$ 4,727,391	$ 787,899	$ 9,454,782

Circulating Dry Scrubber (CDS FGD)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
O&M - Labor																				
O&M - Scheduled Outage	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,402,148	$ 1,402,148	$ -	$ 1,402,148	$ -	$ 2,804,296	$ -	$ 2,804,296	$ 1,402,148	$ -	$ 2,804,296	$ 1,402,148	$ -	$ 2,804,296
O&M - Base Non-Labor	$ -	$ -	$ -	$ -	$ 233,691	$ 233,691	$ 600,921	$ 600,921	$ 233,691	$ 600,921	$ 233,691	$ 1,201,841	$ 233,691	$ 1,201,841	$ 600,921	$ 233,691	$ 1,201,841	$ 600,921	$ 233,691	$ 1,201,841
Total O&M Costs	$ -	$ -	$ -	$ -	$ 233,691	$ 233,691	$ 2,003,069	$ 2,003,069	$ 233,691	$ 2,003,069	$ 233,691	$ 4,006,138	$ 233,691	$ 4,006,138	$ 2,003,069	$ 233,691	$ 4,006,138	$ 2,003,069	$ 233,691	$ 4,006,138
Capital - Direct Unit					$ 433,998	$ 433,998	$ 2,003,069	$ 2,003,069	$ 433,998	$ 2,003,069	$ 433,998	$ 4,006,138	$ 433,998	$ 4,006,138	$ 2,003,069	$ 433,998	$ 4,006,138	$ 2,003,069	$ 433,998	$ 4,006,138
Capital - Construction	$ 63,967,324	$ 70,059,438	$ 77,166,904	$ 46,706,335	$ 11,650,000															
Total Capital Costs	$ 63,967,324	$ 70,059,438	$ 77,166,904	$ 46,706,335	$ 12,083,998	$ 433,998	$ 2,003,069	$ 2,003,069	$ 433,998	$ 2,003,069	$ 433,998	$ 4,006,138	$ 433,998	$ 4,006,138	$ 2,003,069	$ 433,998	$ 4,006,138	$ 2,003,069	$ 433,998	$ 4,006,138
20 Yr Total	$ 63,967,324	$ 70,059,438	$ 77,166,904	$ 46,706,335	$ 12,317,690	$ 667,690	$ 4,006,138	$ 4,006,138	$ 667,690	$ 4,006,138	$ 667,690	$ 8,012,275	$ 667,690	$ 8,012,275	$ 4,006,138	$ 667,690	$ 8,012,275	$ 4,006,138	$ 667,690	$ 8,012,275

Appendix B. Limestone Based Wet FGD – Burns & McDonnell

A.B. Brown Wet Limestone Forced Oxidation FGD Cost Estimate

Vectren Energy Delivery

Vectren A.B. Brown Wet Limestone Forced Oxidation FGD Cost Estimate
Project No. 116946

Revision 0
3/5/2020

A.B. Brown Wet Limestone Forced Oxidation FGD Cost Estimate

prepared for

Vectren Energy Delivery
Vectren A.B. Brown Wet Limestone Forced Oxidation FGD Cost Estimate
Evansville, IN

Project No. 116946

Revision 0
3/5/2020

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, MO

TABLE OF CONTENTS

LIST OF TABLES

Page No.

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
WLSFO	Wet Limestone Forced Oxidation

1.0 EXECUTIVE SUMMARY

Vectren has retained Burns & McDonnell Engineering Company, Inc. (BMcD) to evaluate retrofitting new wet limestone forced oxidation (WLSFO) flue gas desulfurization (FGD) system scrubbers for the two coal units at the A.B. Brown Generating Station (ABB). BMcD was tasked with developing 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 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.

In 2019, Vectren has retained BMcD to provide an all-inclusive cost estimate in 2019 dollars including all ancillary equipment required for a retrofit of this type.

1.1 Replacement Cost Estimate

The FGD technology evaluated by BMcD as a potential 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 received in 2017 from seven FGD system suppliers: Amec Foster Wheeler, Andritz, Babcock & Wilcox, Babcock Power, GE Power, Marsulex and Mitsubishi Hitachi were escalated to 2019 dollars, 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 (2019 Dollars)

Area	Cost
Total Direct Cost	$263,808,600
Indirect Cost	$67,095,900
Contingency	$66,178,000
EPC Fee	$27,795,500
Total Project Cost	$424,878,000

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.

1.2 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 FGD scrubber to help reduce sulfur dioxide emissions. In 1986 Unit 2 was completed also with a FGD 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 develop a screening level FEP-1 (±50%) estimate of the cost to replace the existing scrubbers with new WLSFO 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.

3.0 REPLACEMENT COST ESTIMATE

3.1 Replacement Selection

BMcD and Vectren agreed that BMcD would estimate the wet LSFO technology as a potential replacement for the current FGD system at A.B. Brown. The wet LSFO 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 on coal fired boilers burning high-sulfur coal. 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.

It is BMcD's understanding that Vectren is evaluating differences between wet LSFO and other scrubber technologies by conducting similar cost estimate efforts with others on alternative technologies.

3.2 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 C.

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 or Stebbins tile lined, either of which can handle high chloride levels (up to 50,000 mg/L). The quotes originally received for the FGD equipment in 2017 varied on materials of construction with both flake-glass lined carbon steel and Stebbins tile proposed. Both materials are commonly used in FGD retrofit projects, though BMcD understands that Vectren has had issues with flake-glass lining systems failure in the past. Pricing varied as well with neither coating being a clearly higher cost choice; as such the cost estimate provided will accommodate either material choice.

The absorber inlet (interface of wet and dry flue gas) and outlet ducts would be constructed of C276 (Hastelloy) 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. A limestone pile canopy is included in the estimate. The canopy will allow for up to 7 days of covered limestone storage.

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 gypsum canopy is included in the estimate. The canopy will allow for up to 3 days of covered gypsum storage.

The estimate is based on producing saleable quality gypsum; typically that limits scrubber chloride concentrations to approximately 20,000 mg/L due to cake washing constraints. If chlorides are held to 20,000 mg/L within the scrubber loop a bleed stream of 55 gallons per minute (gpm) will be required for each Unit. The estimate included wastewater treatment equipment for this purge stream consisting of physical/chemical treatment, falling film evaporator and a crystallizer to comply with the current published version of the Effluent Limitation Guidelines (ELG) which require zero discharge for new FGD waste streams. As there is no discharge of FGD wastewater there is no need for specialized Selenium treatment over and above the thermal system. The wastewater treatment system is sized only for the FGD purge stream, it will not treat flow from general plant drains or leachate collection.

The estimate also includes a FGD outage storage tank. The tank is approximately the same size as the absorber reaction tank and will be constructed of similar materials of construction (Stebbins tile or flake glass lined carbon steel). The tank will allow Vectren to empty the reaction tank during a Unit outage for absorber inspection activities. The FGD bleed pumps will transfer slurry from the absorber to this tank. New transfer pumps are included in the estimate to transfer the slurry back to the FGD vessel once outage activities are complete.

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

3.3 Electrical System Evaluation

BMcD evaluated the existing electrical distribution system for AB Brown Units 1 and 2 to determine if upgrades would be required for the additional loads from the new wet LSFO FGD system and its associated ancillary equipment. It was determined that the existing system does not have sufficient capacity for the new auxiliary loads associated with the FGD upgrade. Therefore the estimate includes the following new electrical equipment: two new transformers, new PCM building, new switchgear (4160V and 480V), new MCC's and additional miscellaneous panels.

3.4 Conceptual Design Basis

The design basis for the wet LSFO 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 3-1: 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 (inH_20)	-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 3-2: 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

3.5 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)

- Limestone and Gypsum pile canopies
- Wastewater Treatment Equipment (falling film evaporator and crystallizer)
- Piping outside of the absorber islands
- Electrical (new transformers, PCM, switchgear, MCC's and miscellaneous panels)
- Instrumentation and controls

3.5.1 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.
- Assumes contracting philosophy is Engineer, Procure, Construct (EPC) approach.
- All information is preliminary and should not be used for construction purposes.
- Assumes project engineering starts January 1, 2020 with both scrubbers in operation by January 2024.
- All capital cost and O&M estimates are stated in 2019 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 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. BMcD reviewed the fan curves provided by Vectren and determined there was sufficient capacity to handle the pressure drop through the new FGD system.
- ABB Unit 2 boiler structural improvements were included as this work would be completed during the scrubber tie-in outage.
- This estimate does not include provisions for either Mercury control or SO3 control. Vectren can continue using the existing system for each following conversion to the wet LSFO technology.

3.6 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

3.7 Owner Costs

Allowances for the following Owner's costs are not 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
- Owner's Contingency
- Allowance for Funds Used During Construction (AFUDC).

3.8 Cost Estimate Exclusions

In addition to Owner's costs noted above, the following costs are also excluded from all estimates:

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

3.8.1 Capital Costs

The FEP-1 capital cost estimate for the replacement FGD system is 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 3-3: Capital Cost Estimate Summary (2019 Dollars)

Area	Cost
Total Direct Cost	$263,808,600
Indirect Cost	$67,095,900
Contingency	$66,178,000
EPC Fee	$27,795,500
Total Project Cost	$424,878,000

3.8.2 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. Auxiliary power loads for the new wet LSFO system are estimated to be 10.2 MW, note this does not include power associated with the existing ID fans. Given that the pressure drop between the existing FGD system and replacement FGD system is not expected to be significantly different the impact on ID fan operations should be minimal.

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 gypsum cake at 90% solids (saleable quality) generated by the new Unit 1 and 2 FGD systems is estimated to be 0.1 ton/MWhrg.

The number of operators required to operate the replacement FGD system is expected to be similar to that of the existing FGD system. Additional operators and maintenance staff will likely be needed for the wastewater treatment equipment; up to 5 additional full-time equivalents. 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 limestone used in the new Unit 1 and 2 FGD systems is estimated to be consumed at 0.06 ton/MWhrg. Maintenance labor and material costs are expected to be lower for the replacement FGD system compared to the existing FGD system.

4.0 CONCLUSIONS AND RECOMMENDATIONS

Burns & McDonnell recommends that Vectren consider the information presented in this report when considering the economic viability of a new FGD system. Burns & McDonnell estimates that new scrubbers will cost an order-of-magnitude of $425 million (in 2019 dollars). This includes electrical system upgrades and all BOP considerations.

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 – PROCESS FLOW DIAGRAM

no.	date	by	ckd	description

no.	date	by	ckd	description

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400
FIRM LICENSE NO. xxxxxx

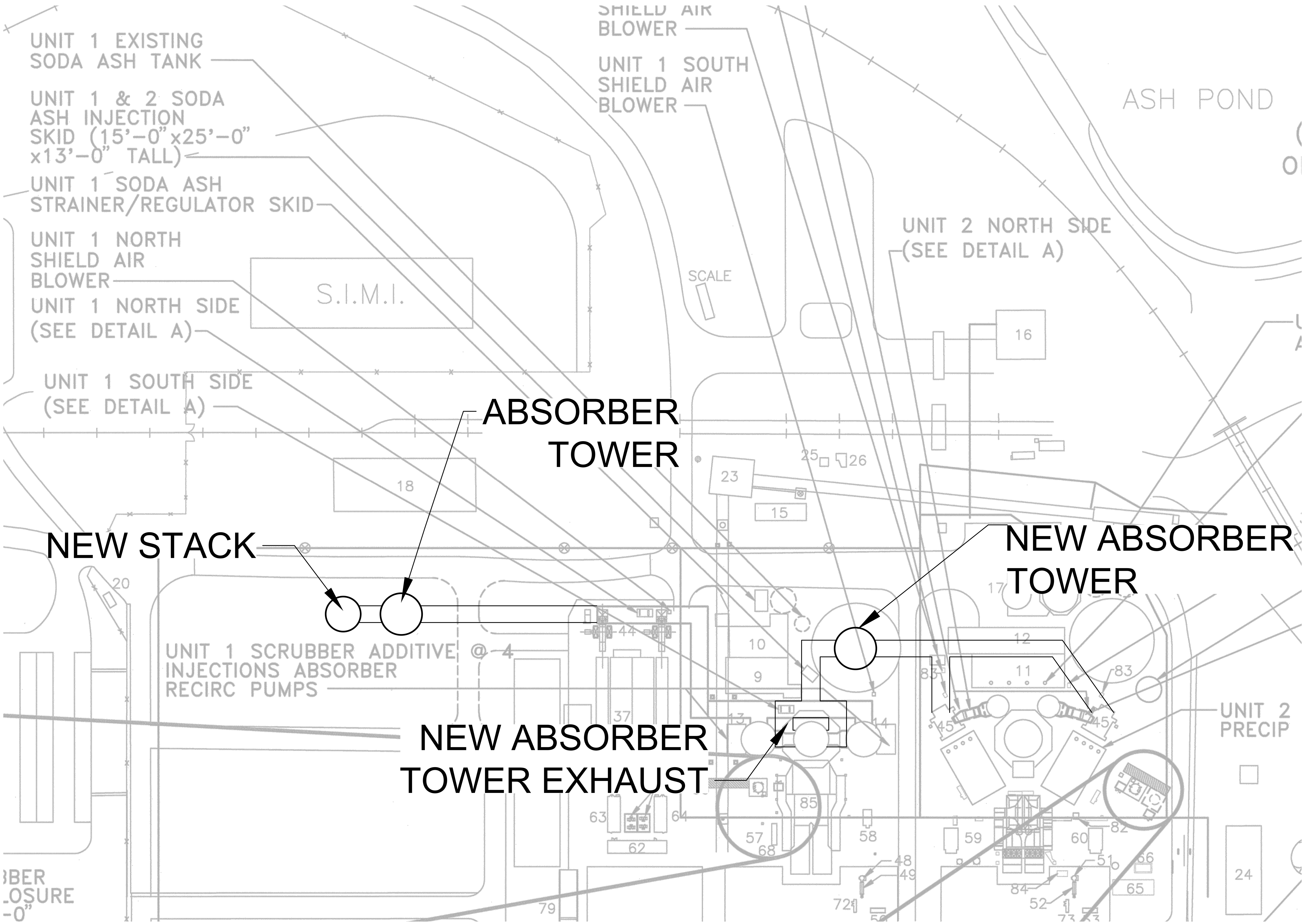
designed: K. BURCHARDT
detailed: R. CHANDLER

VECTREN A.B. BROWN
COUNTY, STATE

PROCESS FLOW DIAGRAM

project: 98818
contract: CONTRACT
drawing: FPD001 – rev. A
sheet 1 of 1 sheets
file PFD001.dwg

APPENDIX C – 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

CREATE AMAZING.

Burns & McDonnell World Headquarters
9400 Ward Parkway
Kansas City, MO 64114
O 816-333-9400
F 816-333-3690
www.burnsmcd.com

VECTREN
A CenterPoint Energy Company

A.B. Brown Power Station FGD Refurbishment Study 10-Year Dual Alkali Scrubber

Revised: May 11, 2020

THREE i DESIGN ENGINEERING + ARCHITECTURE
2425 WEST INDIANA ST EVANSVILLE, IN 47712 P: 812-423-6800 F: 812-423-6814 THREEIDESIGN.COM

Vectren Power Supply
A.B. Brown Power Station
FGD Refurbishment Study
10-Year Dual Alkali Scrubber

Prepared by: Three i Design

Table of Contents

A. INTRODUCTION

Three I Design (Three I Engineering) has been performing engineering and surveying support work in the A.B. Brown FGD Systems and for the A.B. Brown plant facility since the early 1980's. During the last four decades, we have worked with Vectren engineers, maintenance personnel, production personnel, contractors, and consultants, to upgrade FGD systems and plant systems, improve equipment accessibility, improve equipment handling systems, remediate Vectren safety items, and remediate corrosion damaged systems and structures. A very brief list of FGD system engineering support work is included below.

- Re-design and replace entire lime slaking system
- Re-design and replace lime conveying system
- Design and add ball mill system
- Design and add clarifier tank
- Re-design and replace unit no. 2 north and south absorber inlet ducts
- Re-design and replace unit no. 1 north and south absorber outlet ducts
- Re-design and replace unit no. 1 thickener tank rake drive support bridge
- Reinforce unit no. 2 thickener tank rake drive support bridge
- Re-design and replace unit no. 1 belt filter system
- Re-design and replace unit no. 2 belt filter system
- Re-design and replace unit no. 1 north and south absorber outlet duct support structures
- Reinforce unit no. 2 north and south absorber outlet duct support structures.
- Re-design and replace unit no. 1 rotary filter building and belt filter building siding and roofing systems (and support systems) and reinforce floor support steel and roof support steel
- Re-design and replace unit no. 2 regeneration building siding and roofing systems (and support systems) and reinforce floor support steel and roof support steel
- Re-design and replace unit no. 1 lime mixing tank and foundation
- Re-design and replace unit no. 2 lime mixing tank and foundation
- Re-design and replace unit no. 1 and 2 belt filter building ventilation systems
- Yearly unit no. 1 and unit no. 2 FGD system corrosion remediation projects

Based on experience with the A.B. Brown FGD Systems, Vectren asked Three I Design to help identify and organize the A.B. Brown FGD System Operation, Maintenance, and Remediation needs over the next ten years.

B. OBJECTIVE

The objective of this study was to identify systems, areas, and items that require regular or ongoing maintenance and/or remediation, based on historical information. This study also included identifying systems, areas, and items that are not continuous or ongoing remediation items but are expected to require maintenance and/or remediation within the next ten years. This study includes developing a ten-year project schedule for the maintenance and/or remediation, for each FGD system.

There are structures that required significant ongoing corrosion remediation work, and these structures were re-assessed in 2019. The 2019 assessment items included the four absorber vessels and the two thickener tanks.

After the work items were assembled into a ten-year project schedule (for each FGD system), budget pricing was developed for each year, as described below.

C. SCOPE OF WORK FOR FGD REFURBISHMENT STUDY

The following is a brief summary of the process that occurred and the information that was used to develop the budget pricing for Vectren's ten-year FGD plan.

Ten-year Plan - O&M Budget Pricing

The pricing provided was based on historical Vectren O&M information (provided by Vectren), for fiscal years 2011 thru 2018. Based on discussions with Vectren mechanical maintenance and electrical maintenance, the operating and maintenance expenses (2011 thru 2018) should be representative of the O&M expenses during the next ten years excluding overheads, Vectren labor, etc.

Ten-year Plan - Capital Budget Pricing

The pricing provided was based on historical Vectren capital information (provided by Vectren and Vectren's contractors), for fiscal years 2011 thru 2017. The ten-year projected costs are in 2019 dollars and exclude overheads Vectren labor, etc.

For the ten-year capital budget pricing Three I Design identified a list of projects for the first five years (2020 thru 2024). This list includes corrosion remediation items that are part of the most recent Vectren FGD system corrosion review projects (2015 thru 2018), items Vectren has included in their five-year corrosion remediation plan, and corrosion damaged items identified during recent FGD system corrosion review (2019 corrosion review during this project). In addition to corrosion remediation work, the capital project list includes replacing the absorber mist eliminators and adding mist eliminator wash systems in three absorbers (new mist eliminators and a mist eliminator wash system was installed in the Unit No. 2 south absorber at the end of 2015).

For the period 2025 thru 2026 the capital plan remained consistent with the previous 5-year period. During the period 2027-2029, the capital plan includes reductions consistent with an assumed unit retirement for study purpose at the end of 2029.

D. ESTIMATING METHODOLOGY

D.1. OEM Equipment Estimates

O&M Budget Pricing

The FGD Refurbishment Study consisted of eight years of Vectren O&M History (2011 thru 2018) and adjusting the historical information relative to current costs (2019 costs). The O&M budget pricing process also included meeting with A.B. Brown mechanical maintenance and electrical maintenance, to identify if current predictive maintenance and preventative maintenance approaches differ than the practices that were in place from 2011 to 2018. Adjustments were made to the budget pricing for 2020 thru 2029 to account for these practices.

Capital Budget Pricing

The FGD Refurbishment Study consisted of taking seven years of capital history (2011 thru 2017) and adjusting the historical information relative to current costs (2019 costs). Most historical information was provided by the contractor who performed the capital projects in the FGD system during this time. For projects performed by other contractors, this information was provided by the Vectren project managers for each project.

The capital budget pricing process also included reviewing the 2015 FGD system structural corrosion review manuals and field reviewing the equipment and structures in the FGD systems, to identify changes in performance, and to develop a list of capital projects for the 2020 to 2029 system life.

The capital budget pricing process also included performing a 2019 FGD system structural corrosion assessment of the absorber vessels and thickener tanks.

Once the FGD system reviews were complete, and the capital project list developed for 2020 thru 2029, this information was provided to Sterling Industrial, LLC a mechanical & electrical contractor familiar with the plant to develop budget pricing. Three I Design continually met with the Sterling Industrial throughout the process and provided additional concept information.

Budget pricing for 2020 thru 2029 was also compared to historical data and the age and condition of the structures and equipment in the FGD system. Changes were made to be consistent with historical data, which is generally an accurate representation of what is required to maintain these systems based on the age and condition of the structures and equipment in the FGD systems.

D.2. Balance of Plant Equipment Estimates

The descriptions below include references to previous work, previous projects, and previous capital budgets and T&M budget pricing.

The items and work described below are included in the estimates.

All estimates are 2019 dollars.

All estimates exclude overheads, escalation, and Vectren labor.

CCR compliance work was not included in this review.

Lime Silo

Exterior Walls

A corrosion remediation design package was created and bid in 2015. This work has not been completed at the time of this study and is included in the estimates going forward to avoid more extensive structural corrosion remediation work. An allowance for continual minor corrosion remediation is included each year to maintain the structure.

Roof System & Equipment

The roof system and roof mounted equipment was replaced in 2015. An allowance is included in each year for minor corrosion remediation work to maintain the systems and avoid major corrosion remediation in the future.

Ladders and Landings

The ladders and landings were replaced in 2015. An allowance is included in each year for minor corrosion remediation work to maintain the systems and avoid major corrosion remediation in the future.

Internal Walls

The internal walls were inspected, and minor repairs were made in 2015. An allowance is included in each year for minor corrosion remediation work to maintain the systems and avoid major corrosion remediation in the future.

Lime Conveyors

Ongoing Hapman conveyor equipment and conveyor tube maintenance is required, due to abrasion and wear. Regular maintenance costs and conveyor replacement costs are included in the estimate.

Lime Slaking Tank

The lime slaking tank has been replaced including the tank, foundations, platforms, and handrail systems in 1999. Regular corrosion remediation work is to be expected going forward due to the corrosive environment.

Ball Mill

The ball mill has been replaced including the primary equipment, foundations, platforms, stairs, and handrail systems in 1999 Regular corrosion remediation work is expected going forward due to the corrosive environment.

Lime Slurry Storage Tank

The lime slurry storage tank has been replaced including the tank, equipment, foundations, platforms, stairs, and handrail systems in 1996. Regular corrosion remediation work is to be expected going forward due to the corrosive environment.

Corrosion remediation work on the spiral stair to the top of the tank, the landing at the top of the tank, and the stair and the walkway to the belt filter building is included in the estimate.

Lime Slaking Building

The lime slaking building has been replaced including the building, framing, roofing, siding, equipment, foundations, doors, roofing, and siding in 1996. Regular corrosion remediation work is to be expected going forward due to the corrosive environment.

Unit No. 1 North and South Absorbers

Shell Disc & Donut, Internal Structural Repairs & Flake-glass Coating

Developed scope of work based on historical outage upgrades and repairs. Estimate includes necessary improvements and repairs based on outage schedule going forward.

Anchor Bolts and Anchor Chairs

Extensive corrosion remediation repairs were performed in 2011-2012 on the bottom of the absorbers. Based on the significant ongoing corrosion damage around the base of the absorbers these repairs will need to be performed in the future and this scope is included in the estimate.

Shell Plate

Shell replacement work was performed in 2011-2012. Based on assessment of the large number of external cover plates currently located on the absorbers, this work should be performed in 2020, and in 2025. This scope has been included in the estimate. See Corrosion Review Reports for vessel structural stability associated with external cover plates, and horizontal planes in the vessel shell that are perforated from corrosion damage.

External Stiffeners

Repairs will be needed on the external stiffeners in the next ten years. This scope is included in the estimate. The external shell stiffening work that was performed in 2011-2012 was used to develop this estimate.

Mist Eliminators, Mist Eliminator Supports, & Mist Eliminator Wash Piping

Replacement of the mist eliminators, mist eliminator supports, & mist eliminator wash piping in the north and south absorbers including the dome stiffeners, access opening in dome (and framing), access platform at dome opening, and jib crane for handling mist eliminator equipment, etc. is included in the estimate.

Access Platforms, Walkways, Stairs, and Ladders

Corrosion remediation is an ongoing process on these structures and this process is expected to continue, based on the corrosive environment. This scope is included in the estimate.

Ultrasonic Thickness Testing (Corrosion Remediation)

Vectren hired Three I Design to perform ultrasonic thickness testing, temporary patch plate location work, and corrosion review work on these vessels in 2019. In order to manage risk on these structures, Vectren should continue the current structural shell replacement process of removing damaged shell and installing new shell. This type of repair is outage work and should be performed during every outage, to replace all temporary patch plates with new in-line shell plate. This scope is included in the estimate.

In conjunction with the approach to managing risk, it is recommended that the bottom of each vessel be completely replaced. The original designer of the vessels specified the bottom of these vessels be insulated. Absorber liquid from vessel leaks and leaking expansion joint leaks filled the insulation area and held the corrosive liquid against the outside surface of the vessels. Significant metal loss occurred before Vectren understood how much damage occurred and permanently removed the insulation system.

For budgeting purposes and the replacement schedule, the vessel replacement could occur in three consecutive outages (one third of the vessel, each outage). This approach is included in the estimate.

Unit No. 1 North and South Absorber Inlet Duct

The north absorber inlet duct and nozzle has an excessive amount of liquid leaking, and this liquid is causing damage to the base of the absorber and adjacent structures. The north absorber inlet duct and nozzle needs to be repaired or replaced in 2020. This scope had been included in the estimate.

This work should also be performed on the south absorber inlet duct, so this structure doesn’t cause damage to the base of the absorber or adjacent structures. This scope has been included in the estimate.

In the past, the outlet duct expansion joints have leaked onto the top of the inlet ducts and saturated the inlet duct insulation and caused significant damage to the insulation, cladding, duct shell, duct stiffeners, and duct supports. Vectren has made modifications in this area including fiberglass cladding on the areas under the expansion joints, however, if this area is saturated with scrubber liquor in the future, the resulting corrosion remediation costs have not been addressed in this ten-year estimate.

Unit No. 1 North and South Absorber Outlet Duct

The coated carbon steel elbow on the south absorber outlet duct system was replaced with a stainless steel duct elbow in 2018. This approach is planned and included in the estimate for the north absorber.

Significant corrosion remediation and shell plating work was performed on the north and south absorber outlet ducts and the breech ducts previously. This work is included in each outage estimate for the next ten years.

Unit No. 1 North and South Absorber Inlet Duct Support Structures

These structures were repaired within the last two years, but minor corrosion remediation work will be required to maintain them. This scope is included in the estimate. If the duct work is not maintained additional corrosion remediation work on the support structures will be required.

Unit No. 1 North and South Absorber Outlet Duct Support Structures

These structures have been replaced within the last two years, so only minimal work should be required to maintain them. This scope is included in the estimate. If the expansion joints are not maintained, additional corrosion remediation work will be required.

Unit No. 1 North and South Absorber Access Platforms, Stairs, Ladders, etc.

These structures have been replaced within the last two years, so only minimal work should be required to maintain them. This scope is included in the estimate. If the expansion joints are not maintained, additional corrosion remediation work will be required.

Unit No. 1 North and South Absorber Recirc. Pump Buildings

These buildings were replaced in 2013 and these structures are performing relatively well. Minor corrosion remediation work is included in each year, to avoid major corrosion remediation work in the future.

Unit No. 1 North and South Absorber Recirc. Pumps Concrete Foundations

There is cracking in the concrete and exposed reinforcing steel on the pump concrete foundations. Pump concrete foundation replacement work is included for all four concrete foundations.

Unit No. 1 North and South Absorber Bleed Piping

This 10” diameter piping system is mostly the original FMC fiberglass piping. Most of this piping is outside and exposed to UV rays (outside surfaces) and harsh chemicals on the inside surfaces. Replacement of this piping system is included in the estimate.

Unit No. 1 North and South Absorber Regeneration Return Piping

This 14" diameter piping system was replaced in 1997 and 2013. This piping system probably won't need to be completely replaced before 2030 but will require minor corrosion remediation work. This scope is included in the estimate.

Unit No. 1 North and South Absorber Regeneration Return Valve Access Platform

Replace access platforms in 2019 or 2020. T&M Budget Pricing was developed in 2018. This scope is included in the estimate.

Unit No. 1 Alley Pipe Supports

All Supports in the Unit No. 1 Alley need to be replaced (FMC Corporation drawings 00246-608-1 thru 00246-608-3). The columns will be in new locations, so the columns can be installed before any existing structures are removed (so the existing utilities can be supported from the existing pipe support system and then transferred to the new support system, without excessive false-work). This scope is included in the estimate.

Unit No. 1 Alley Underground Drain Piping and Manholes

Vectren has performed ongoing corrosion remediation work on the underground piping and manholes. This work will need to continue, and this scope is included in the estimate.

Unit No. 1 Thickener Tank

Thickener Tank Rim

Replace top 2'-6" of rim. This work will be similar to the rim replacement work that was performed in 2008/2009, however, a new rim angle will need to be added to the entire perimeter and the angle will need to continue through the vertical structural tee shell stiffeners. Rim angle to be 4"x4"x3/8". This scope is included in the estimate.

Thickener Tank Vertical Shell Stiffeners

The bottom portion of nearly every vertical structural tee's is missing. Install all new vertical structural tee's on shell. Match the existing member size. The new vertical structural tee's will be placed mid-way between the existing vertical structural tee's. The damaged tee's will be abandoned in place. This scope is included in the estimate.

Thickener Tank Bridge

Entire bridge needs to be sand blasted and painted. As with previous projects, due to the amount of visual corrosion damage, this process will include a significant amount of structural discovery work/structural repairs. This scope is included in the estimate.

Thickener Tank Bridge Utility Supports, Rake Canopy, and Handrail System

Entire system needs to be sand blasted and painted. As with previous projects, due to the amount of visual corrosion damage, include a significant amount of structural discovery work/structural repairs. This scope is included in the estimate.

Thickener Tank Shell and Floor Plate

Internal corrosion remediation was performed on the thickener tank shell and floor plates in 2010. This type of work will need to be performed, at least once, during the next ten years. This scope is included in the estimate.

The outside surface of the thickener tank shell (and all shell stiffeners) should be sand blasted and coated. This scope is included in the estimate.

Thickener Tank Launder, Regeneration Return Nozzles, and Emergency Overflow

On-going corrosion remediation work is performed on these items and this repair process should continue. Most of this work requires emptying the tank (or at least lowering the liquid level). Liquid level adjustments are by Vectren. This scope is included in the estimate.

Ultrasonic Thickness Testing (Corrosion Remediation)

Vectren hired Three I Design to perform ultrasonic thickness testing, temporary patch plate location work, and corrosion review work on this tank in 2019. In order to manage risk in this million-gallon capacity tank, it was suggested that the tank be completely replaced. This remediation is appropriate. Over the last forty years, Vectren has performed a significant amount of temporary reinforcing and temporary patch plate repairs on this tank (floor cover plates, shell cover plates, corner reinforcement, partial shell replacement, etc.). The bottom portion of the vertical stiffeners, horizontal stiffening ring, and exterior floor to shell weld are also significantly damaged.

For budgeting purposes and the replacement schedule, the tank replacement is to occur in three consecutive outages (one third of the tank, each outage). This scope is included in the estimate.

Unit No. 1 Lime Mixing Tank

The lime mixing tank was completely replaced in 2013. The lime mixing tank is inspected by Vectren during each outage and the re-designed tank is performing much better than the previous tank. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 1 Soda Ash Tank

The access platform and perimeter handrail system on top of the tank will need to be replaced within the ten-year time frame. This scope is included in the estimate.

Unit No. 1 Old Rotary Filter Building

Structural Steel and Floor Support Steel

Major corrosion remediation work has been performed in this building over the last ten years. The corrosion remediation work over the next ten years should be less than the previous ten years, however, corrosion damage is expected, and corrosion remediation needed each year, to avoid major corrosion remediation work. This scope is included in the estimate.

Trench Drain System

The trench drain that runs north and south adjacent to the vacuum pump is showing significant signs of differential settlement and the old truck bay concrete foundation is cracked and shifted, which has caused a shift and cracking in the block wall that sits on the concrete foundation. This trench drain system should be replaced. The old truck bay concrete foundation and block wall should be repaired. This scope is included in the estimate.

First Floor Stair

Based on the corrosive environment and the history of this system, corrosion damage is expected, and corrosion remediation needed within the ten-year time frame. This scope is included in the estimate.

Second Floor Stair Tower

This abandoned corrosion damaged stair tower should be removed and the utilities attached to the stair tower should be re-supported. This scope is included in the estimate.

Chemical Sump

The grating, grating support steel and handrail system have been repaired numerous times. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Waste Water Sump

The grating, grating support steel and handrail system have been repaired numerous times. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 1 Belt Filter Building

South Stair Tower

This stair system was replaced in 2014. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Structural Steel and Floor Support Steel

Major corrosion remediation work has been performed in this building over the last ten years. The corrosion remediation work over the next ten years should be less than the previous ten years, however, the metal deck and concrete were not replaced (this work was postponed). There is a significant amount of corrosion damage in the metal deck. Corrosion remediation will be needed. The south edge beam (at the lime mixing tank) also needs to be reinforced or replaced. Minor corrosion damaged is also expected and corrosion remediation needed. This scope is included in the estimate.

Roof and Roof Support Steel

The roof system was supposed to be replaced, but this work was postponed for several years. This work needs to be performed (replace all roof purlins and reinforce roof support beams). Since this work has been postponed for several years, more extensive corrosion damage is expected, and more extensive corrosion remediation needed. This scope is included in the estimate.

Haul Truck Canopy

Corrosion remediation work was performed on the framing and knee brace for this canopy in 2013. There was also T&M Budget Pricing developed for replacing the purlins and roofing material for the canopy and this work was postponed for several years. This work needs to be performed. The east perimeter/edge beam and the north perimeter/edge beam need to be replaced in a similar manner to the south perimeter/edge beam that was replaced in 2013. This scope is included in the estimate.

Unit No. 1 Horizontal Belt Filter

The horizontal belt filter was completely replaced in 2015 and this system appears to be performing relatively well, however, this area is an extremely corrosive area and on-going minor corrosion remediation work should be included (every year), to avoid major corrosion remediation work in the future. This scope is included in the estimate.

Unit No. 1 Horizontal Belt Filter Drop Chute

The carbon steel horizontal belt filter drop chute was completely replaced in 2015 with a stainless steel drop chute. This system appears to be performing well, and only occasional minor corrosion remediation is anticipated. This scope is included in the estimate.

Unit No. 1 Lime Silo Enclosure

The upper portion of the north and south lime silos has been removed, but the lower portion (columns and cone) were not removed because this area is an enclosure that is still used to protect operating equipment. All wall girts, purlins, and minor support steel need to be replaced with new, and new siding and roofing installed. This scope is included in the estimate.

The main columns and bracing on the lime silos appear to be in relatively good condition and the load on these structures has been greatly reduced, therefore, only minor corrosion remediation is needed. This scope is included in the estimate.

Unit No. 1 Underflow Piping

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 1 Underflow Tunnel

The access platform and stairs into the tunnel need to be replaced. This scope is included in the estimate.

There are numerous areas where the concrete reinforcing steel is exposed and the large areas where the concrete reinforcing steel has dissolved away, completely. The tunnel needs significant corrosion remediation. This scope is included in the estimate.

Catwalk and Utility Support between Unit 1 and Unit 2

Major structural remediation work was performed in 2018, however, based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed, including complete replacement of the utility supports. This scope is included in the estimate.

Unit No. 1 & Unit No. 2 Emulsified Sulfur System and Enclosure

Vectren moved the Unit No. 2 emulsified sulfur pumping system over to the Unit No. 1 emulsified sulfur tank, so this tank provides emulsified sulfur to the Unit No. 1 thickener tank and the Unit No. 2 thickener tank. The structures in this system appear to be performing well. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Minor corrosion remediation is need for the pump enclosure. This scope is included in the estimate.

The Unit No. 1 emulsified sulfur tank agitator support beams and the attachments to the fiberglass tank need to be sand blasted and coated. This scope is included in the estimate.

Unit No. 1 Switchgear Building

The roofing system on this building has been repaired several times in the past. The roof needs to be replaced and minor corrosion remediation is needed for the building structure. This scope is included in the estimate.

Unit No. 2 North and South Absorbers

Shell Disc & Donut, Internal Structural Repairs & Flake-glass Coating

Corrosion remediation is an ongoing process with a yearly budget. This scope is included in the estimate.

Anchor Bolts and Anchor Chairs

The anchor bolts and anchor chairs on the Unit No. 2 absorbers have not experienced the extensive damage that has occurred on Unit No. 1, based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Shell Plate

The shell replacement work that was performed in 2012/2013 is expected to be necessary again in the next ten years, due to the corrosive environment and based on the large number of external cover plates currently located on the absorbers. This scope is included in the estimate.

External Stiffeners

The external stiffeners on the Unit No. 2 absorbers have not experienced the extensive damage that has occurred on Unit No. 1, however, based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Mist Eliminators, Mist Eliminator Supports, & Mist Eliminator Wash Piping

Replace the mist eliminators, mist eliminator supports, & mist eliminator wash piping in the north absorber. Use 2015 Unit No. 2 south absorber mist eliminator replacement pricing (adjust pricing to current year). This work needs to include the absorber dome stiffeners, access opening in dome (and framing), access platform at dome opening, jib crane for handling mist eliminator equipment, etc. This scope is included in the estimate.

Access Platforms, Walkways, Stairs, and Ladders

Corrosion remediation is an ongoing process on these structures and this process is expected to continue, based on the corrosive environment. This scope is included in the estimate.

Ultrasonic Thickness Testing (Corrosion Remediation)

Vectren hired Three I Design to perform ultrasonic thickness testing, temporary patch plate location work, and corrosion review work on these vessels in 2019. In order to manage risk on these structures, Vectren should continue the current structural shell replacement process of removing damaged shell and installing new shell. This type of repair is outage work and should be performed during every outage, to replace all temporary patch plates with new in-line shell plate. This scope is included in the estimate.

Unit No. 2 North and South Absorber Inlet Duct

Unit No. 2 north and south absorber inlet duct have both been replaced in the last twenty years, along with ongoing corrosion remediation. This is an extremely corrosive area. Based on the corrosive environment, the history of this system, and the ten-year period, ongoing corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 2 North and South Absorber Outlet Duct

The south absorber outlet duct system was replaced in 2015 with a stainless steel. This replacement is expected for the north absorber. This scope is included in the estimate.

If the duct replacement is delayed, additional corrosion remediation work will be required.

Unit No. 2 North and South Absorber Inlet Duct Support Structures

These structures have significant corrosion damage and should be replaced. This replacement should include replacing the access platforms and ladders. This scope is included in the estimate.

Unit No. 2 North and South Absorber Outlet Duct Support Structures

Major corrosion remediation work was performed in 2016/2017, however, due to the expansion joints in the absorber outlet ducts, and the history of ongoing corrosion damage in this area, similar corrosion remediation is expected in 2025 and minor corrosion remediation in other years, to avoid major corrosion remediation work. This scope is included in the estimate.

Unit No. 2 North and South Absorber Access Platforms, Stairs, Ladders, etc.

Ongoing corrosion remediation work has been performed on these structures. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 2 North and South Absorber Recirc. Pump Building

The siding and roofing were replaced in 2011, but the system was not installed per the manufacturer's installation instructions and panels are not attached properly to the support steel. Some re-work was performed in 2015 when the west wall columns failed, and structure remediation work was performed on the west wall. Ongoing repair work is expected. This scope is included in the estimate.

There are several areas around the trench drains that have differentially settled. Trench drain re-work is expected in the next ten years. This work includes repairing floor areas that have settled (in addition to the areas around the trench drains). This scope is included in the estimate.

Unit No. 2 North and South Absorber Recirc. Piping

This piping system is a combination of original 1985 FMC fiberglass piping and fiberglass piping that was installed in 1998. Replacement of this piping system is expected, and this scope is included in the estimate.

Unit No. 2 North and South Absorber Bleed Piping

This 10" diameter piping system is mostly the original FMC fiberglass piping. Replacement of this piping system is expected, and this scope is included in the estimate.

Unit No. 2 North and South Absorber Regeneration Return Piping

There doesn't appear to be any coating system on the regeneration return piping. based on the number of times the Unit No. 1 regeneration return piping has been replaced, it is expected that this piping system will need to be completely replaced. This scope is included in the estimate.

Unit No. 2 North and South Absorber Regeneration Return Valve Access Platform

This platform was replaced in 2006/2007. Based on the amount of corrosion damage in this area, minor ongoing corrosion remediation will be needed on this structure to avoid a complete replacement within ten years. This scope is included in the estimate.

Unit No. 2 Pipe Supports between Absorbers

The bottom portions of the utility and pipe supports in this area were replaced a couple years ago, but the steel was never coated. Structural corrosion remediation is required for these supports and then all supports need to be sand blasted and painted. This scope is included in the estimate.

Unit No. 2 Thickener Tank

Thickener Tank Rim

Replace top 2'-0" of rim. This work will be similar to the rim replacement work that was performed in 2008/2009 Unit No. 1. This scope is included in the estimate.

Thickener Tank Bridge

Entire Bridge needs to be sand blasted and painted. Based on the corrosive environment, history of corrosion on this structure, corrosion damaged is expected to be discovered after sand blasting, and corrosion remediation needed. This work should include the bridge support columns. This scope is included in the estimate.

Thickener Tank Bridge Utility Supports, Rake Canopy, and Handrail System

Entire system needs to be sand blasted and painted. As with previous projects, due to the amount of visual corrosion damage, include a significant amount of structural discovery work/structural repairs will be needed. This scope is included in the estimate.

Thickener Tank Shell and Floor Plate

Based on the corrosive environment, the history of this system, and the ten-year period, ongoing corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

The outside surface of the thickener tank shell (and all shell stiffeners) needs to be sand blasted and coated. This scope is included in the estimate.

Thickener Tank Launder, Regeneration Return Nozzles, and Emergency Overflow

On-going corrosion remediation work is performed on these items and this repair process should continue. Most of this work requires emptying the tank (or at least lowering the liquid level). Liquid level adjustments are by Vectren. This scope is included in the estimate

Ultrasonic Thickness Testing (Corrosion Remediation)

Vectren hired Three I Design to perform ultrasonic thickness testing, temporary patch plate location work, and corrosion review work on this tank in 2019. In order to manage risk in this million-gallon capacity tank, it was suggested that the tank be completely replaced. This remediation is appropriate. Over the last thirty-five years, Vectren has performed a significant amount of temporary reinforcing and temporary patch plate repairs on this tank (floor cover plates, shell cover plates, partial shell replacement, etc.).

For budgeting purposes and the replacement schedule, the tank replacement is to occur in three consecutive outages (one third of the tank, each outage). This scope is included in the estimate.

Unit No. 2 Lime Mixing Tank

Major corrosion remediation was performed on the lime mixing tank in 2017. The lime mixing tank is inspected by Vectren during each outage and the re-designed tank is performing better than the previous tank. However, over a ten-year period, it is safe to assume some corrosion remediation will be needed. The internal roof support steel was also abandoned in place. This steel should be inspected during each outage and any compromised members should be removed. This work will require internal scaffolding. This scope is included in the estimate.

Unit No. 2 Soda Ash Tank

The access platform and perimeter handrail system on top of the tank should be replaced within the ten-year time frame. This scope is included in the estimate.

Regular minor corrosion remediation on the spiral stair to the top of the soda ash tank should be performed to avoid major corrosion remediation in the future. This scope is included in the estimate.

Unit No. 2 Belt Filter Building (Regeneration Building)

Structural Steel, Roof Support Steel, and Floor Support Steel

Major corrosion remediation work has been performed in this building over the last ten years. The corrosion remediation work over the next ten years should be less than the previous ten years, however, based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Vectren recently removed many of the masonry block walls in this building and there is corrosion damage on the beams that have been exposed, since the block walls were removed. These beams need to be sand blasted and painted. Based on the history in this building, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

The coating system for the roof support steel is not performing well. This steel needs to be sand blasted and coated. Based on the history in this building, corrosion damage is expected after sand blasting and corrosion remediation needed, prior to installing the coating system. This scope is included in the estimate.

The coating system on the center support beam in the truck bay (and center support for the filter cake drop chute) is not performing well. This steel needs to be sand blasted and coated. Based on the history in this building, corrosion damage is expected after sand blasting and corrosion remediation needed, prior to installing the coating system. This scope is included in the estimate.

The x-bracing (including connection plates) on the east face of this belt filter building, near the lime mixing tank needs to be completely replaced. This replacement process will be similar to the x-bracing replacement work that has been performed several times in the Unit No. 1 belt filter building. This scope is included in the estimate.

Siding and Roofing Systems

The siding and roofing was replaced in 2011, but the system was not installed per the manufacturer’s installation instructions and panels are not attached properly to the support steel. A large area of the west wall failed and was replaced in 2017. Ongoing repair work is expected on these systems. This scope is included in the estimate.

Haul Truck Canopy

Corrosion remediation work was performed on the framing and knee braces for this canopy in 2011, but the east edge beam has corrosion damage, and this beam should be replaced (and all connection plates). This scope is included in the estimate.

Internal Stair (South)

Based on the history in this building, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

External Stair Tower (North)

Corrosion remediation has been performed several times in the last ten (plus) years, but none of the repairs have been coated. This entire structure needs to be sand blasted and painted, since some of the repairs occurred a long time ago. Based on the history, corrosion damage is expected and sand blasting and corrosion remediation is needed, prior to installing the coating system. This scope is included in the estimate.

Unit No. 2 Chemical Sump

Vectren replaced the grating support steel with stainless steel and this system appears to be performing relatively well.

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 2 Wastewater Sump

The handrail system has been repaired over the years, and it is safe to assume that this ongoing process will continue.

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 2 South Horizontal Belt Filter

The south horizontal belt filter frame was completely replaced in 2013 (the north horizontal belt filter was removed last year). The coating system on the frame has completely failed. Corrosion remediation on the structural frame will be needed soon. After the major corrosion remediation is complete, minor ongoing corrosion remediation will be needed. This scope is included in the estimate.

Unit No. 2 Horizontal Belt Filter Drop Chute

The carbon steel horizontal belt filter drop chute was replaced in 2015 with a stainless steel drop chute. This system appears to be performing well, and only occasional minor corrosion remediation is anticipated. This scope is included in the estimate.

Unit No. 2 Underflow Piping

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 2 Clarifier Tank Pipe Rack

This structure is no longer used for its intended purpose (the 24” diameter and 36” diameter pipes are empty and abandoned in place). The structure is at a reduced structure loading, however, there is significant amount of corrosion damage to the two columns that support this tall structure. This pipe rack should be removed and the SBS compressor utilities routed on a new support system. Any other piping and electrical utilities that are still in use should also be relocated. This process would be similar to the 2016/2017 removal of the Unit No. 2 FMC CEMS building platform and re-supporting the piping and electrical utilities that were attached to the platform columns. This scope is included in the estimate.

Unit No. 2 Switchgear Room

See Section on absorber recirc. pump building.

D.3. List of Major Corrosion Remediation Projects

Unit 1 – 2020

- North and South Absorber Access Platforms, Stairs, Ladders, etc. - Remediation
- Replace North and South Regen. Return Valve Access Platforms
- Replace Alley Pipe Supports
- Alley Underground Drain Piping - Corrosion Remediation
- Alley Drainage Manhole - Corrosion Remediation
- Haul Truck Canopy - Replace Beams, Purlins, and Roof Panels
- Lime Silo Enclosure - Replace Siding System and Roof System
- Underflow Access Platform and Stairs - Corrosion Remediation
- Underflow Tunnel Repair - Concrete & Reinforcing Steel - Corrosion Remediation
- Thickener Tank - Replace Exterior Coating
- Thickener Tank - Corrosion Remediation/Discovery Work
- Thickener Tank Vertical Shell Stiffeners
- Old Rotary Filter Building Trench Repair
- Old Rotary Filter Building Truck Bay Block Wall Repair

Unit 2 – 2020

- Thickener Tank - Replace Exterior Coating System
- Thickener Tank - Corrosion Remediation/Discovery Work
- North Outlet Duct Repairs
- Replace North and South Inlet Duct Support Structures
- North and South Absorber Access Platforms, Stairs and Ladders, Etc. - Remediation
- North and South Recirc. Pump Building Trench Drains and Floor - Remediation
- North and South Absorber Regen. Return Valve Access Platform - Replace Coatings
- Regen. Return. Platform - Discovery Work
- Pipe Supports Between Absorbers - Corrosion Remediation
- Regen. Building Siding and Roofing - Corrosion Remediation
- Belt Filter Building Internal Stairway (South) - Coating
- Belt Filter Building Internal Stairway (South) - Corrosion Remediation/Discovery Work
- Belt Filter Building External Stairway (North) - Coating
- Belt Filter Building External Stairway (North) - Corrosion Remediation/Discovery Work
- Lime Silo Exterior Walls - Corrosion Remediation
- Disc & Donut, Shell, Sump, and Duct Repair
- Thickener Tank Bridge Coating
- Regeneration Building Southeast X Bracing - Replace
- Regeneration Building Grit Pit Area Perimeter Beams - Coating Replacement
- Misc. Piping Replacement
- North and South Absorber Shell Plates

- Replace Top Landing on Lime Slurry Storage Tank
- Lime Slurry Storage Tank Roof Support Steel - Corrosion Remediation
- Clarifier Tank - Dome Top - Corrosion Remediation
- Clarifier Tank - Rake Drive Support Steel and Access Platform - Corrosion Remediation
- Clarifier Tank - Walkway and Stairs - Corrosion Remediation

Unit 1 – 2021
- North and South Inlet Duct at Scrubbers - Replace
- North and South Outlet Duct Repairs - Partial Replacement & Remediation
- North and South Inlet Duct Support Structures - Replace Posts
- Replace North Quench Sprays
- Replace South Quench Sprays
- North and South Absorber Outlet Duct Structures - Remediation
- North Absorber Inlet Expansion Joint Replacement 1-15
- North Absorber Inlet Expansion Joint Replacement 1-23
- North Absorber Inlet Expansion Joint Replacement 1-18B
- South Absorber inlet Expansion Joint Replacement 1-17
- South Absorber Inlet Expansion Joint Replacement 1-18A
- North Absorber Outlet Expansion Joint Replacement
- South Absorber Outlet Expansion Joint Replacement
- Alley Underground Drain Piping - Corrosion Remediation
- Alley Drainage Manhole - Corrosion Remediation
- Thickener Tank Bridge - Corrosion Remediation/Discovery Work
- Thickener Tank Bridge and Utility Supports, Rake Canopy, and Handrail System - Replace Coating
- Soda Ash Tank Install Drains and piping
- Soda Ash Tank Grating (Remove and Install)
- Switch Gear Building - Remediation
- Disc & Donut, Shell, Sump, and Duct Repair
- North and South Absorber Access Platforms, Stairs, ladders, Etc.
- Replace Thickener Tank Rim and Launder - Shop Fabrication
- Replace Thickener Tank Rim and Launder - Exterior and Interior Coating
- Replace Thickener Tank Rim and Launder
- Misc. Piping Replacement
- North and South Absorber Shell plates

Unit 2 – 2021
- North Absorber Inlet Expansion - Replace
- South Absorber Inlet Expansion - Replace
- North Absorber Outlet Expansion (1st one off scrubber) - Replace
- North Absorber Outlet Expansion (At Stack) - Replace
- South Absorber Outlet Expansion (1st one off scrubber) - Replace
- South absorber Outlet Expansion (At Stack) - Replace

- North Outlet Duct Repairs - Remediation
- North and South Inlet Duct Support Structures - Remediation
- North and South Absorber Access Platforms, Stairs and Ladders, etc. - Remediation
- Thickener Tank Rim - Remediation
- Regen Building Siding and Roofing - Remediation
- Clarifier Tank Pipe Rack - Remove & Replace SBS Air Compressor Utilities
- Lime Silo Fill Lines - Replace
- Disc & Donut, Shell, Sump, and Duct Repair
- Misc. Piping Replacement
- North and South Absorber Shell plates
- Replace Walkway From Lime Slurry Storage Tank to Regen. Building
- Clarifier Tank - Shell and Floor - Corrosion Remediation
- Clarifier Tank - Enclosure - Corrosion Remediation
- Clarifier Tank - Tank Floor Support Steel - Corrosion Remediation

<u>Unit 1 – 2022</u>

- North and South Absorber Anchor Bolts and Chairs
- North and South Absorber Shell plates
- North and South Absorber External Stiffeners
- North and South Tower - Replace Flake Glass Liner (Complete Replacement)
- North and South Tower Patching, Vertical Supports And Plates (Drawing 70 thru 74)
- North and South Absorbers Support Post (Drawing 76)
- North and South Absorber Supports (Drawing 77)
- North and South Absorber Alloy Bands and External Stiffening (drawing 78)
- North and South Absorber Repairs to Inlet Duct and Absorber Interface And Internal Awning
- North and South Absorber wall repairs after cleaning
- Replace North Absorber Mist Eliminators
- Replace South Absorber Mist Eliminators
- North Absorber Cone Repair and Reinforcement
- South Absorber Cone Repair and Reinforcement
- North and South Inlet Duct at Scrubbers
- North and South Outlet Duct - Corrosion Remediation
- North and South Inlet Duct Support Structures - Corrosion Remediation
- North and South Absorber Outlet Duct Structures
- North Absorber Outlet Elbow Duct
- Thickener Tank Shell and Floor Plate
- Disc & Donut, Shell, Sump, and Duct Repair
- North and South Absorber Access Platforms, Stairs, Ladders, Etc. - Remediation
- Belt Filter Roof Support Steel - Corrosion Remediation
- Replace Belt Filter Roof System (including purlins and roofing panels)
- Replace Acid Brick Liner in Absorber Sumps

<u>Unit 2 – 2022</u>

- North and South Absorber Access Platforms, Stairs and Ladders, Etc.
- Regen Building Siding and Roofing
- Haul Truck Canopy - Remediation
- Replace Soda Ash Tank Stairway
- Purchase Material for North Absorber Mist Eliminators
- Purchase Material for North Absorber Duct Replacement

<u>Unit 1 – 2023</u>

- Alley Underground Drain Piping - Remediation
- Alley Drainage Manhole - Remediation
- North and South Absorber Access Platforms, Stairs, ladders, Etc.
- Old Rotary Filter Building Coating
- Horizontal Belt Filter Building Coating
- Old Rotary Filter Building - Remediation
- Horizontal Belt Filter Building Coating - Remediation
- Belt Filter Building Floor Replacement
- Soda Ash Tank Access Platform and Perimeter Handrail system

<u>Unit 2 – 2023</u>

- Absorbers Inside Liner Replacement
- North and South Absorber Anchor Bolts and Chairs
- North and South Absorber Shell Plates
- North and South Absorber External Stiffeners
- North Mist Eliminators - Install
- North and South Mist Eliminators Wash Access Platforms and Walkways Corrosion
- North Outlet Duct Replacement - Install
- North and South Inlet Duct Support Structures
- North Quench Spray Piping
- South Quench spray Piping
- North and South Absorber Access Platforms, Stairs and Ladders, Etc.
- North and South Bleed Piping - Replace
- Thickener Tank Shell and Floor Plate Internal Remediation
- Regen Building Siding and Roofing
- South Horizontal Belt Filter - Replace Frame and Main Rollers
- Disc & Donut, Shell, Sump, and Duct Repair
- Replace Absorber Recirc. Piping
- Replace Acid Brick Liner in Absorber Sumps

<u>Unit 1 – 2024</u>

- North and South Inlet Duct at Scrubbers
- North and South Outlet Duct Repairs

- North and South Inlet Duct Support Structures
- North Quench Sprays
- South Quench Sprays
- North and South Absorber Outlet Duct Structures
- North Absorber Inlet Expansion Replacement 1-15
- North Absorber Inlet Expansion Replacement 1-23
- North Absorber Inlet Expansion replacement 1-18B
- South Absorber inlet Expansion Replacement 1-17
- South Absorber Inlet Expansion Replacement 1-18A
- North Absorber Outlet Expansion Replacement
- South Absorber Outlet Expansion Replacement
- Alley Underground Drain Piping - Remediation
- Alley Drainage Manhole - Remediation
- Thickener Tank Bridge Utility Supports, Rake Canopy, and Handrail System Coating
- Disc & Donut, Shell, Sump, and Duct Repair
- North and South Absorber Access Platforms, Stairs, ladders, Etc.
- Lime Mixing Tank - Remediation
- Misc. Piping Replacement
- North and South Absorber Shell plates

Unit 2 – 2024

- North and South Inlet Duct Support Structures
- North and South Absorber Access Platforms, Stairs and Ladders, Etc.
- Regen Building Siding and Roofing
- Replace Thickener Tank Bridge
- Disc & Donut, Shell, Sump, and Duct Repair
- Lime Mixing Tank - Remediation
- Misc. Piping Replacement
- North and South Absorber Shell plates

E. ESTIMATE ASSUMPTIONS & CLARIFICATIONS

- The project list contains major projects and major tasks.
- Budget pricing for all years is in 2019 dollars.
- The capital projects have not been designed or engineered; therefore, all budget pricing is conceptual only.
- The cost for each outage year includes $1,000,000 for absorber disc and donut repairs and interior shell repairs. This is based on the current Vectren repair approach.
- The cost for the major outage year for unit no. 1 includes $3,500,000 for the north and south absorber mist eliminator and mist eliminator wash system replacement. This is a Vectren planned replacement.
- The cost for the major outage year for unit no. 2 includes $1,700,000 for north absorber mist eliminator and mist eliminator wash system replacement. This is a Vectren planned replacement.
- An engineering cost of 20% for all capital work is included in the budget pricing.
- Costs for planned work were estimated using historical costs from 2011 – 2017 and contractor budget pricing.
- The budget pricing is based on Vectren's current operating practices, maintenance practices, outage approaches, corrosion remediation practices, management practices, etc. If Vectren management, engineering, maintenance, and/or operations, change their practices, the changes may affect the projected costs.
- The budget pricing does <u>not</u> include allowances for changes in EPA requirements, changes in CCR regulations, etc.
- The budget pricing is based on good maintenance and repair practices, which includes quickly repairing all leaks.
- The historical Vectren O&M and capital (2011 thru 2018) was used as reference information for budget pricing data.

F. RISKS ASSOCIATED WITH OPERATION BEYOND TEN ADDITIONAL YEARS

Unit No. 1 was designed and installed in 1977/1978 and Unit No. 2 was designed and installed in 1983/1984. In 2030, Unit No. 1 will be older than fifty years and Unit No. 2 will be almost fifty years old.

FMC Corporation, who designed the original FGD Systems, didn't identify a service life for the systems or the components. Generally, if no system life is identified, the expected service life would be less than fifty years. Many system components can have a ten to twenty-year service life. In excessively corrosive environments, the expected service life needs to be de-rated, consistent with the corrosion rate.

The FGD system is a very corrosive environment, and even though there has been ongoing repair work and major repair work in numerous areas of the Unit No. 1 and Unit No. 2 FGD systems, the infrastructure is still basically the original FMC Corporation infrastructure.

Operating a system beyond its design service life or anticipated service life results in reduced structural capacity and integrity, increased occurrences of equipment failure, increased Operating and Maintenance Costs, reduced system reliability, reduced system availability, and increased safety risks.

APPENDIX: COST TABLES

10 Year O&M/CapEx Estimate
9/27/2019

ABB DA Summary	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M - Scheduled Outage	$700,000	$1,000,000	$700,000	$700,000	$1,100,000	$800,000	$900,000	$1,500,000	$1,200,000	$1,400,000	$2,300,000
O&M - Base Non-Labor	$2,900,000	$3,100,000	$3,200,000	$3,400,000	$3,600,000	$3,800,000	$4,100,000	$4,700,000	$5,700,000	$7,000,000	$7,300,000
Total O&M Costs	$3,600,000	$4,100,000	$3,900,000	$4,100,000	$4,700,000	$4,600,000	$5,000,000	$6,200,000	$6,900,000	$8,400,000	$9,600,000
Capital - Direct Unit	$9,400,000	$15,500,000	$18,100,000	$13,800,000	$11,900,000	$8,200,000	$6,900,000	$9,200,000	$7,400,000	$7,300,000	$8,300,000
Capital - Construction	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	$9,400,000	$15,500,000	$18,100,000	$13,800,000	$11,900,000	$8,200,000	$6,900,000	$9,200,000	$7,400,000	$7,300,000	$8,300,000
20 Yr Total	$13,000,000	$19,600,000	$22,000,000	$17,900,000	$16,600,000	$12,800,000	$11,900,000	$15,400,000	$14,300,000	$15,700,000	$17,900,000

ABB1 Dual Alkali Re-Furbish	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor											
O&M - Scheduled Outage	$200,000	$500,000	$500,000	$200,000	$600,000	$600,000	$300,000	$800,000	$900,000	$400,000	$1,200,000
O&M - Base Non-Labor	$1,500,000	$1,600,000	$1,700,000	$1,800,000	$1,900,000	$2,000,000	$2,200,000	$2,500,000	$3,000,000	$3,700,000	$3,800,000
Total O&M Costs	$1,700,000	$2,100,000	$2,200,000	$2,000,000	$2,500,000	$2,600,000	$2,500,000	$3,300,000	$3,900,000	$4,100,000	$5,000,000
Capital - Direct Unit	$2,700,000	$9,200,000	$15,900,000	$2,200,000	$7,200,000	$4,600,000	$2,500,000	$4,800,000	$5,000,000	$2,700,000	$4,800,000
Capital - Construction											
Total Capital Costs	$2,700,000	$9,200,000	$15,900,000	$2,200,000	$7,200,000	$4,600,000	$2,500,000	$4,800,000	$5,000,000	$2,700,000	$4,800,000
20 Yr Total	$4,400,000	$11,300,000	$18,100,000	$4,200,000	$9,700,000	$7,200,000	$5,000,000	$8,100,000	$8,900,000	$6,800,000	$9,800,000

ABB2 Dual Alkali Re-Furbish	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor											
O&M - Scheduled Outage	$500,000	$500,000	$200,000	$500,000	$500,000	$200,000	$600,000	$700,000	$300,000	$1,000,000	$1,100,000
O&M - Base Non-Labor	$1,400,000	$1,500,000	$1,500,000	$1,600,000	$1,700,000	$1,800,000	$1,900,000	$2,200,000	$2,700,000	$3,300,000	$3,500,000
Total O&M Costs	$1,900,000	$2,000,000	$1,700,000	$2,100,000	$2,200,000	$2,000,000	$2,500,000	$2,900,000	$3,000,000	$4,300,000	$4,600,000
Capital - Direct Unit	$6,700,000	$6,300,000	$2,200,000	$11,600,000	$4,700,000	$3,600,000	$4,400,000	$4,400,000	$2,400,000	$4,600,000	$3,500,000
Capital - Construction											
Total Capital Costs	$6,700,000	$6,300,000	$2,200,000	$11,600,000	$4,700,000	$3,600,000	$4,400,000	$4,400,000	$2,400,000	$4,600,000	$3,500,000
20 Yr Total	$8,600,000	$8,300,000	$3,900,000	$13,700,000	$6,900,000	$5,600,000	$6,900,000	$7,300,000	$5,400,000	$8,900,000	$8,100,000

ABB BPT	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor											
O&M - Scheduled Outage											
O&M - Base Non-Labor											
Total O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital - Direct Unit											$0
Capital - Construction											
Total Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20 Yr Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

ABB LF Leachate	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor											
O&M - Scheduled Outage											
O&M - Base Non-Labor											
Total O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital - Direct Unit											
Capital - Construction											
Total Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20 Yr Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

ABB Selenium	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor											
O&M - Scheduled Outage											
O&M - Base Non-Labor											
Total O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital - Direct Unit											$0
Capital - Construction		$0	$0	$0							
Total Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20 Yr Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

ABB DBA	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

O&M - Labor											
O&M - Scheduled Outage											
O&M - Base Non-Labor											
Total O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital - Direct Unit											
Capital - Construction											
Total Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20 Yr Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

ABB DFA	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor											
O&M - Scheduled Outage											
O&M - Base Non-Labor											
Total O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital - Direct Unit											
Capital - Construction											
Total Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20 Yr Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

ABB By-Products Landfill	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor											
O&M - Scheduled Outage											
O&M - Base Non-Labor											
Total O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital - Direct Unit											
Capital - Construction											
Total Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20 Yr Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Assumptions

1 All costs are expressed in 2019 dollars. No Escalation is included.
2 Total Capital costs are +/- 50% and include the costs associated with the purchase of equipment, erection, and all contractor services.
3 Total Capital costs do not include contingency, owners cost, taxes, insurance, spare parts, or construction utility interconnections/consumables.
4 BPT and Selenium treatment is common equipment for both units
5 Leachate and WW Hg Treatment is included in BPT treatment Total Capital Costs
6 O&M Base Non-Labor cost for BPT and Selenium treatment assumed 2% equipment capital costs for maintenance items, consumables and spare parts. Variable O&M costs are not included.
7 Capital Direct cost for BPT and Selenium treatment assumed 4% equipment capital cost for equipment replacement during major outage
8 BPT treatment Total Capital Costs includes all common water treatment infracture.
9 Selenium treatment Total Capital costs includes only biological treatment which requires the BPT treatment system and entire infrastructure upstream for effluent compliance
10 DBA and DFA rates to be established by Vectren

BPT Reagent Data				
Reagent	**Unit Pricing**		**Usage Rate**	
Coagulant Feed	1.4	$/gal	15	gal/MWhr
Polymer	7.5	$/gal	5	gal/MWhr
Dewatering Polymer	7.5	$/gal	5	gal/MWhr
Sodium Hypochlorite	0.95	$/gal	2.1	gal/MWhr
Sodium Bisulfite	2.4	$/gal	1.1	gal/MWhr
Organosulfide	3	$/gal	15	gal/MWhr

Landfill Assumptions/Clarifications
ADDITIONAL COSTS NOT REFLECTED ABOVE:
Closure (calendar year 2040) = $6M
Post-Closure (30 years) beginning in 2041 = $0.2M per year.
*Closure costs move up if landfill is no longer used.

A wastewater treatment facility is constructed at the AB Brown Station. Those costs are not included here. Internal treatment cost assumed to be $0.05 per gallon.
No inflation escalator has been included. All etimates are based on 2019 prices.

ESTIMATES DO NOT INCLUDE:
Mitigation of wetland areas disturbed by construction.
Project management/supervision by Vectren.
Legal costs associated with zoning.
Purchase of property.
Investigations and/or remediation associated with groundwater impact.
Waste delivery to landfill costs.

Attachment 6.7 Environmental Compliance Options Study

FINAL

REVIEW OF ENVIRONMENTAL COMPLIANCE

A.B. Brown Unit 1 and 2

F.B. Culley Unit 2

B&V PROJECT NO. 400278
B&V FILE NO. 40.0003

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

20 MAY 2020

BLACK & VEATCH

Table of Contents

LIST OF TABLES

1.0 Executive Summary

Southern Indiana Gas and Electric Company d/b/a Vectren Power Supply, Inc. (Company) has contracted with Black & Veatch Corporation (Consultant) to serve as an Owner's Engineer (OE) in the evaluation of coal combustion residuals (CCR) and effluent limit guideline (ELG) regulations for A.B. Brown (ABB) and F.B. Culley (FBC) Power Stations.

On April 17, 2015, the Environmental Protection Agency (EPA) published in the Federal Register the final CCR rule. The CCR rule contains specific requirements that are to be met to continue operation of the CCR unit(s). Failure to meet specific requirements will require operation to cease and closure or retrofit of the CCR unit to begin. For units that are required to close, the CCR rule allows for two options: (1) leave the CCR in place and install a final cover system or (2) remove the CCR and decontaminate the unit.

The EPA finalized an update to the ELG rule on September 30, 2015. The final rule strengthens the technology based ELGs by introducing more stringent discharge restrictions on toxic pollutants. Changes include new standards for flue gas desulfurization (FGD), flue gas mercury control (FGMC), gasification, and landfill leachate waste streams that were previously included under low volume wastes. Additionally, it establishes a zero-discharge standard for fly and bottom ash transport waste streams for both new and existing point sources. The final rule did not include any changes to the previously specified cooling tower blowdown, once-through cooling, or coal pile runoff effluent standards.

On September 18, 2017, the EPA postponed compliance dates in the 2015 rule for best available technology (BAT) effluent limitations and pretreatment standards for existing sources (PSES) for FGD wastewater and bottom ash transport water until new rulemaking could be completed. On May 23, 2019, the EPA released its rulemaking timeline, indicating a new proposed rule would be issued in June 2019, with the final rule issued in August 2020. On November 22, 2019, EPA published the new proposed rule which would revise requirements to FGD wastewater and bottom ash transport water.

The National Pollutant Discharge Elimination System (NPDES) permit issued to A.B. Brown Station in 2017 (effective date of April 1, 2017) by the Indiana Department of Environmental Management (IDEM) was subsequently modified in 2018 and contains new, more strict effluent limitations for copper, chloride, and selenium. Pursuant to the permit, the facility must comply with the final effluent limitations for these constituents by April 1, 2020.

1.1 A.B. BROWN STATION

A.B. Brown Station is a two unit, 530 megawatt (MW) coal fired electricity generating power facility, located on the northern bank of the Ohio River, 5 miles southwest of Evansville, Indiana. The station includes Unit 1 with a rated capacity of 265 MW and Unit 2 with a rated capacity of 265 MW. A.B. Brown Station currently utilizes an ash pond for ash handling and settling pond for wastewater treatment, as well as collection of metal cleaning, FGD wash water, other process wastewaters, treated sanitary wastewaters, and storm water.

Closure of the ash pond because of the CCR ruling represents a significant reduction in reuse water, storage, and settling capabilities for A.B. Brown. Of the wastewater streams regulated under the EPA's revised ELG rule, only fly ash transport, bottom ash transport, low volume wastewater, and leachate apply to A.B. Brown. Discharge of ash transport water is no longer permissible and, as such, a new means of transport and storage of CCR materials will be necessary. All wastewater flows into the ash pond will now need to be re-directed, collected, and properly treated prior to discharge.

1.2 F.B. CULLEY STATION

F.B. Culley Station is a two unit, 387 MW coal fired electricity generating power facility, located on the northern bank of the Ohio River, southeast of Newburgh, Indiana. The station includes Unit 2 with a rated capacity of 100 MW and Unit 3 with a rated capacity of 287 MW.

As with the A.B. Brown units, the CCR regulations require F.B. Culley to discontinue the use of the Unit 2 and Unit 3 ponds, referred to as east and west, respectively. The elimination of both CCR units represents a significant reduction in storage and settling capabilities for F.B. Culley.

F.B. Culley Unit 3 is planned for a dry bottom ash conversion in 2020 utilizing a submerged chain conveyor. This report discusses the upgrade options for F.B. Culley Unit 2 to also meet CCR and ELG regulations.

1.3 OBJECTIVE

The focus of the ELG/CCR Compliance Program is to identify alternative ash handling and water treatment options as well as any water reclamation or elimination options for each regulated discharge stream to bring A.B. Brown and F.B. Culley Stations into future compliance with the updated CCR and ELG regulations.

This report provides the following:

- A review of the updated CCR for both A.B. Brown Units 1 and 2 and F.B. Culley Unit 2.
- ELG regulations and NPDES permit limitations and their impact on A.B. Brown Units 1 and 2, including timing of the respective rules and application.
- An evaluation of bottom ash and fly ash solutions, design concepts, feasibility, and present worth of capital and operating expenses for each option for both A.B. Brown Units 1 and 2 and F.B. Culley Unit 2.
- An evaluation of treatment technology options for A.B. Brown Units 1 and 2 with respect to the updated ELG rulings including design concepts, feasibility, and present worth of capital and operating expenses.

1.4 SUMMARY OF RECOMMENDATIONS

The following recommendations are proposed for each unit.

Table 1-1 Summary of Recommended Technologies – A.B. Brown Station

OPTION	TECHNOLOGY DESCRIPTION	CAPITAL COST	O&M COST
ELG Equipment (Table 4-1)	Physical/Chemical and Biological, Collection and Filtration, Location 2	$43,072,000	$1,378,000
Bottom Ash	Modified SCC Bottom Ash Handling	$29,927,200	$1,260,500
Fly Ash	Dry Pneumatic Fly Ash Handling	$22,652,300	$3,679,300

Table 1-2 Summary of Recommended Technologies – F.B. Culley Station

OPTION	TECHNOLOGY DESCRIPTION	CAPITAL COST	O&M COST
Wet-to-Dry Ash Handling	Indoor Dewatering Tanks	$3,868,000	$300,300

2.0 Summary of Evaluations

This section summarizes the ELG/CCR Compliance Program ("Projects") for A.B. Brown (ABB) and F.B. Culley (FBC) Stations.

2.1 COAL COMBUSTION RESIDUALS RULING

2.1.1 Background

On April 17, 2015, the Environmental Protection Agency (EPA) published in the Federal Register the final CCR rule. As expected, the rule regulates CCR as nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The rule was published in the Federal Register on April 17, 2015, and it was effective on October 19, 2015.

The CCR rule contains specific requirements that are to be met to continue operation of the CCR unit(s). These requirements include the following:

- Location restrictions.
- Design criteria, including liner design and structural integrity.
- Operating criteria including air criteria, hydrologic and hydraulic capacity requirements, and inspection requirements.
- Groundwater monitoring and corrective action.
- Closure and post-closure care.
- Recordkeeping, notification, and internet posting.

Failure to meet or document the above items generally results in requirements to cease operation and begin closure or retrofit of the CCR unit. For units that are required to close, the CCR rule allows for two options; either to leave the CCR in place and install a final cover system (i.e., close in place) or remove the CCR and decontaminate the unit (i.e., clean closure).
Regardless of the selected closure option, in the event of groundwater contamination, closure is not deemed complete until groundwater is no longer exceeding groundwater protection standards

Clean closure requires dewater and excavation of all CCR, removal of the underlying impacted soil, and final backfill with clean soil. This option removes any groundwater contamination risks so any groundwater remediation (if required) is limited to treating the residual contamination. The option also requires only top soil, which eliminates the need for an engineered cap or any post-closure care. The drawbacks are the significant construction costs associated with the dewatering, excavation, and backfill efforts in addition to long construction durations.

Close in place requires dewatering and regrading of the existing surface, backfill efforts, and an engineered cap. This option results in minimal disturbance of the existing CCR, reduced backfill with relatively short construction schedule, and lowered costs. This option does require an engineered cap, typically a geosynthetic layer, and regularly scheduled post-closure care including groundwater monitoring for 30 years. There are more risks involved with this option because the potential for groundwater contamination remains and there is a significant cost for groundwater remediation if groundwater is incised with CCR.

2.1.2 Implementation and Enforcement

The rule is self-implementing; therefore, affected facilities must comply with the new regulations irrespective of whether a state adopts the rule. Even if a state promulgates its own rule and incorporates the federal criteria into the state's solid waste management program, the federal rule remains in place as an independent set of federal criteria that must be met (although the EPA states in the preamble that facilities in compliance with an EPA-approved state CCR solid waste management plan that is identical to or more stringent than the federal criteria should be viewed as meeting or exceeding the federal criteria). Because the rule is promulgated under Subtitle D, it does not require regulated facilities to obtain permits, does not require the states to adopt and implement the new rules, and cannot be enforced by the EPA. The rule's only compliance mechanism is for a state or citizen group to bring an RCRA citizen suit in federal district court under RCRA Section 7002 against any facility that is alleged to be in noncompliance with the new requirements.

2.1.3 Applicability

The rule applies to new and existing landfills and surface impoundments used to manage CCR generated by coal fired electric utility plants in North American Industry Classification System (NAICS) Industry Code 221112. The rule also applies to inactive surface impoundments (i.e., impoundments not receiving CCR on or after October 19, 2015, but that still contain CCR and liquid) located at power plants producing electricity regardless of fuel type.

2.2 EFFLUENT LIMITATION GUIDELINE RULE

2.2.1 Background

As authorized by the Clean Water Act (CWA), the National Pollutant Discharge Elimination System (NPDES) permit program controls water pollution by regulating discharge point sources into bodies of water in the United States. Wastewater discharges from Vectren facilities are regulated under the Indiana Department of Environmental Management (IDEM) NPDES program that incorporates the standards set forth in the 40 Code of Federal Regulations (CFR) 423, Steam Electric Power Generating Point Source category.

Guidelines set forth under 40 CFR 423 establish wastewater discharge standards for existing point sources that represent the degree of effluent reduction that can be achieved by application of the best available technology (BAT) that is economically achievable. Guidelines for discharges from new point sources are set forth in new source performance standards (NSPS). In addition, guidelines for existing and new sources that discharge into a publicly owned treatment works (POTW) are established for pretreatment standards for existing sources (PSES) and/or pretreatment standards for new sources (PSNS). These guidelines and standards are to be used by the NPDES permitting authority (IDEM in Indiana) in setting applicable discharge limits for specified effluents in new and renewed NPDES and pretreatment permits for steam electric generation facilities.

In 2015, the EPA released a final rule updating the ELGs in 40 CFR 423. The updated rule strengthened the technology based ELGs by introducing more stringent discharge restrictions on toxic pollutants. Changes included new standards for flue gas desulfurization (FGD), flue gas mercury control (FGMC), gasification, and landfill leachate waste streams that were previously included under low volume wastes. In November 2019, the EPA released a proposed rule to further update the ELGs in 40 CFR 423, which is only applicable to FGD wastewater and bottom ash transport water. The proposed rule would establish BAT effluent limitations for total suspended solids (TSS), mercury (Hg), arsenic (As), selenium (Se), and nitrate/nitrite as nitrogen in FGD wastewater discharges. For bottom ash, the proposal includes a TSS BAT effluent limitation and a not-too-exceed 10 percent volumetric purge limitation. The proposed rule proposes subcategories with separate requirements, including high flow facilities (>4 MGD of FGD wastewater), low utilization boilers (876,000 MWh per year or less), and boilers retiring by 2028.

2.2.2 Review of ELG Final Rule

The 2015 ELG rule update was applicable to Vectren facilities that established separate definitions and categories for FGD wastewater and combustion residual leachate, which were previously considered low volume waste sources.

The EPA's rulemaking sets forth technology-based effluent standards for discharges from these new wastewater streams to surface waters and POTW sewer systems. NPDES permitting authorities (IDEM in Indiana) have been incorporating the 2015 ELG standards as applicable into each existing facility's NPDES permit renewals.

The 2015 ELG rule established more stringent BAT effluent limitation guidelines and standards for the various waste streams generated by new and existing steam electric facilities (i.e., FGD wastewater, bottom ash transport water, combustion residual leachate, flue gas mercury control wastewater, fly ash transport water and gasification wastewater). The new proposed rule proposes to amend the more stringent effluent limitations guidelines and pretreatment standards for existing sources in the 2015 rule that apply to FGD wastewater and bottom ash transport water. Where BAT limitations are more stringent than previously established, the new rule proposes that those limitations would not apply until a date determined by the permitting authority (IDEM in Indiana) that is as soon as possible on or after November 1, 2020, but that is no later than December 31, 2023, (for bottom ash transport water) or December 31, 2025 (for FGD wastewater).

The proposal also includes a voluntary incentives program that provides the certainty of more time (until December 31, 2028) for plants to adopt additional process changes and controls that achieve more stringent limitations on mercury, arsenic, selenium, nitrate/nitrite, bromide, and total dissolved solids in FGD wastewater. The optional program provides plants more flexibility, such as additional time, that previous incentives programs.

The technology basis for discharges from existing point sources applicable to the subject Vectren facilities set forth in the proposed 2019 ELG rule are shown in Table 2-1.

Table 2-1 Technology Basis for BAT/PSES and NSPS/PSNS Effluent Limitation Guidelines

WASTE STREAMS	EXISTING BAT AND PSES	NEW NSPS AND PSNS
Fly Ash Transport Water	Dry Handling	Dry Handling
Bottom Ash Transport Water	Dry Handling/Closed Loop Bottom ash transport water on not-too-exceed 10 percent volumetric purge	Dry Handling/Closed Loop Bottom ash transport water on not-too-exceed 10 percent volumetric purge
Wet FGD Wastewater	Chemical Precipitation + Biological Treatment Low residence Biological treatment Membranes	Evaporation
Combustion Residual Leachate	Gravity Settling Impoundment	Chemical Precipitate

2.3 A.B. BROWN--IMPACT OF CCR REGULATIONS

A.B. Brown Station currently utilizes one ash pond. The pond is designed as a surface impoundment. The pond receives bottom ash and fly ash water and the FGD wash water flows, as well as process wastewater, treated sanitary wastewaters and stormwater.

Future closure of the ash pond represents a significant reduction in reuse water, storage, and settling capabilities for A.B. Brown. In conjunction with the ELG ruling, discharge of ash transport water will no longer be permissible and, as such, a new means of transport and storage of CCR materials will be necessary.

2.4 A.B. BROWN--TECHNOLOGY OPTIONS FOR CCR COMPLIANCE

Black & Veatch worked with Vectren to evaluate different cost-effective concepts of bottom ash handling at A.B. Brown Units 1 and 2.

Following the evaluation, Black & Veatch recommended incorporation of a submerged chain conveyor (SCC) underneath the boiler to replace the current sluicing system at A.B. Brown. An SCC uses a submerged drag chain to collect ash and discharge the dewatered ash into a bunker for final dewatering and storage. Subsequently, the ash would be managed for beneficial reuse or disposal. Conversion to SCC may require cooling water depending on final design parameters. The basis for the SCC for the A.B. Brown units is based on the current design, which is in progress for F.B. Culley Unit 3. This design is a United Conveyor Corporation (UCC) submerged flight conveyor (SFC) system. The installed cost to retrofit both A.B. Brown Unit 1 and Unit 2 boilers with SCC equipment has been incorporated into the treatment options in Section 4.0, Table 4-3.

A technology comparison matrix for the bottom ash alternatives described for A.B. Brown Units 1 and 2 is provided in Table 2-2.

Table 2-2 A.B. Brown Units 1 and 2 Bottom Ash Technology Comparison Matrix

ALTERNATIVE	SUBMERGED CHAIN CONVEYOR (ALTERNATIVE 1)	DEWATERING BUNKER (ALTERNATIVE 2)	REMOTE SUBMERGED CHAIN CONVEYOR (ALTERNATIVE 3)
Description	Alternative 1 consists of a new submerged chain conveyor under the existing bottom ash hopper and existing grinders. The submerged chain conveyor will be routed out of the Boiler Building, discharging on an exterior pile or waiting truck.	Alternative 2 is a concrete dewatering bunker. The bottom ash is sluiced through piping to a remote bunker location. A concrete bunker is used to separate the larger particles while a settling tank is used to separate the smaller fines.	Alternative 3 provides a remote closed loop system outside of the existing Boiler Building. The existing bottom ash hopper and sluicing pump would deliver the ash to the new remote dewatering containment equipped with a new submerged chain conveyor that would dewater and deliver the ash to a three-sided bunker for truck removal.
Technical Feasibility	A submerged chain conveyor is often used for removing and dewatering bottom ash from boilers and is a sound technical approach.	The dewatering bunker system is complex with many pumps, piping, and concrete bunkers.	Remote recirculation systems are often used for bottom ash conversions. The technical feasibility is sound but may not be financially viable for small units.
Total Contracted Cost	$29,927,200	$36,448,900	$41,656,700
Operations and Maintenance Cost	$1,260,500	$1,539,400	$1,463,500
Estimated Additional Manpower	1.8	3.6	2.4
Estimated Footprint (sq. ft.)	400	20,000	6,000
Major Equipment	• Submerged chain conveyor. • Hydraulic power unit. • Instrumentation and controls. • Quench water overflow tank, pump, and heat exchanger. • Chain wash spray system. • Three-sided concrete bunker. • Motor control center (MCC) to feed new motors and pumps.	• Transfer tank with jet pump. • Water supply tank and sluice transfer pumps. • Dewatering bunker. • Bunker sump pumps. • Settling tank and sludge pumps. • Surge tank and sluice recirculation pumps. • New overhead door on operating floor. • Instrumentation and controls. • MCC to feed new motors and pumps.	• New remote hopper with new submerged chain conveyor. • Hydraulic power unit. • Instrumentation and controls. • Return water pumps and piping. • Chain wash spray system. • Distribution sluice piping. • MCC to feed new motors and pumps.
Advantages	• Allows for the continued use of existing bottom ash hopper and grinders. • Ash quench water is treated as low volume wastewater.	• Allows for continued use of existing ash hopper. • Minimal outage time for modification of the existing boiler.	• Minimal outage time for modification of the existing boiler.
Disadvantages	• Requires truck operators throughout the day, but could be reduced if three-sided concrete structure were included. • Requires modification of the existing Boiler Building foundation.	• This alternative has a large amount of footprint needed for the separation tanks and dewatering bunker. Therefore, the only available location is the long distance north of the unit. • Due to this length, excessive piping and larger pumps are involved. • Requires front-end loaders with support crews for bottom ash removal from dewatering bunker. • Ash sluicing water needs to be maintained in a closed loop or treated prior to discharge.	• Requires new foundations for remote equipment. • Requires weather protection for the collection trough. • Requires a three-sided concrete containment structure with weather protection. • Requires freeze protection. • Requires lengthy sluice piping and potential for booster pumps. • Ash sluicing water needs to be maintained in a closed loop or treated prior to discharge.
Reliability	The reliability of the submerged chain conveyor is proven	The dewatering tanks, bunker, and sluice piping are a proven approach to ash dewatering.	Remote recirculation systems are often used for bottom ash conversions. The technical feasibility is sound but may not be financially viable for small units.
Recommended for Further Review	Yes	No	No

2.4.1 Existing System and Conceptual Design Basis

The bottom ash system will be designed to receive bottom ash from the existing Units 1 and 2, each rated at 265 MW per pulverized coal fired unit.

The existing ash collection hopper consists of two pyramidal hoppers with two clinker grinders. Jet pumps located at the discharge of the clinker grinders are used to sluice the bottom ash from the bottom ash hopper to the ash storage pond using a single sluice pipe. The existing hopper cooling water overflows from the bottom ash hopper by gravity to an existing plant drain for the alternatives proposed below.

The conceptual design for this study is based on a maximum ash production rate of 3 tons per hour.

2.4.2 Bottom Ash Conceptual Design Alternatives

The following conceptual design alternatives were developed for A.B. Brown Units 1 and 2.

2.4.2.1 Submerged Chain Conveyor (Alternative 1)

Alternative 1 consists of a new submerged chain conveyor under the existing bottom ash trough and existing grinders. The submerged chain conveyor will be routed out of the Boiler Building, discharging to a CCR rule-compliant storage area or transport truck.

Refer to Drawing 190507-PFD-4004 for the material flow. Table 4-4 outlines the estimated cost. The major equipment for this alternative includes the following:

- Submerged chain conveyor.
- Hydraulic power unit.
- Programmable logic controller (PLC) control system and instrumentation.
- Motor control center (MCC) to feed new motors.
- Chain wash spray system.

The submerged chain conveyor consists of a water filled lower trough with submerged drag chain flights attached to two chains to move the ash. The inclined conveyor section dewaters the ash and discharges the ash directly into a dump truck. The dump truck can then haul the dewatered ash for beneficial reuse or disposal.

This operation may require two trucks, with one truck located under the discharge point of the conveyor and another truck to haul ash to a storage location. Dump truck operators would be required 7 days per week with full shift coverage on a 24-hour basis to maintain shifts for around-the-clock manpower coverage. A three-sided concrete bunker could be installed outside the plant building to reduce the number of trucks and operators required. In this case, a front-end loader could be used to remove ash from the bunker and load the dump trucks on a single shift per day.

The existing seal troughs have been modified to a dry seal configuration that will eliminate the need for cooling water usage.

Key comparisons for Alternative 1 include the following:

- Disadvantages of the submerged chain conveyor:
  - Requires truck operators throughout the day.
  - Requires a weather structure over the exterior storage pile/truck loading platform.
  - May require front-end loaders.
- Advantages of the submerged chain conveyor:
  - Comparatively minimal new equipment.
  - Continuous removal of ash.

2.4.2.2 Dewatering Bunker (Alternative 2)

Alternative 2 is a dewatering bunker for the dewatering technology. The reason for the selection is the expected lower capital cost with this alternative, as compared to other dewatering alternatives such as a dewatering bin system, dewatering basin system, and remote closed loop systems.

Refer to Drawing 190507-PFD-4005 for the material flow. Table 4-4 outlines the estimated cost. The major equipment for this alternative includes the following:

- Transfer tank with jet pump.
- Water supply tank.
- Sluice transfer pumps.
- Dewatering bunker and sump.
- Bunker sump pumps.
- Settling tank.
- Surge tank.
- Sludge pumps.
- Sluice recirculation pumps.
- PLC control system and instrumentation.
- MCC to feed new motors and pumps.

The difference between a dewatering bunker and a dewatering basin is that a dewatering bunker is used to collect only heavy ash particles (above 1/16 inch) whereas a dewatering basin system with both an ash dewatering basin and a polishing basin is used to capture both the heavy or large ash particles in the ash dewatering basin and the fine particles in the polishing basin. The dewatering bunker is sized for only 1 day of ash storage, so the size of the bunker is small and the capital cost is low. A front-end loader is required to remove ash from the bunker 7 days per week for each day that the unit is at full load and ash is pulled to the bunker. The sump adjacent to the bunker collects the sluice water.

The dewatering bunker system pulls the bottom ash from the bottom ash hoppers and it sluices to the new bottom ash transfer tank using the existing ash sluice pump.

The water from the transfer tank gravity flows to the new water supply tank to supply water to one of two redundant sluice transfer pumps; bottom ash is conveyed from the bottom ash transfer tank to the dewatering bunker. The jet pump at the discharge of the transfer tank removes the ash from the tank. The sluice water flows by gravity from the dewatering bunker to the dewatering bunker sump over the concrete weir located between the bunker and the sump. The bottom ash in the dewatering bunker is segregated from the sump by the concrete weir and a perforated metal screen to keep lumps of ash (over approximately 1/4 to 1/16 inch in size) from entering the sump.

The bunker sump pump is used to pump the sluice water to the settling tank where the fine ash solids are settled in the tank. The sludge is pumped from the settling tank to the storage pile in the bottom ash bunker. The water in the settling tank gravity flows to the surge tank to supply water to the sluice recirculation pumps, recycling the water back to the plant and the existing ash sluice pump.

The bottom ash bunker is sized for 1 day of storage (72 tons). The water level in the dewatering bunker is kept at a constant level and does not require draining to remove the ash from the bunker. A front-end loader removes the ash from the bunker (while there is water in the bunker) and fills dump trucks hauling ash to the intermediate storage location at the plant site. The front-end loader needs to have a wheel axle height higher than the water level in the bunker.

Key comparisons for Alternative 2 include the following:

- Disadvantages of the dewatering bunker:
  - Since this alternative requires pumps, tanks, and concrete structures, a large site area is needed.
  - Numerous pieces of new equipment are required.
  - A lengthy amount of sluice piping is required to deliver the ash to the remote location for the new bunker.
  - Front-end loaders with support crews are required.
  - Ash sluicing water must be 100 percent accounted for and maintained in a closed loop or treated prior to discharge.
- Advantages of the dewatering bunker:
  - Allows for the continued use of existing bottom ash hopper, grinders, and sluice pumps.

2.4.2.3 Remote Submerged Chain Conveyor (Alternative 3)

Alternative 3 provides a remote closed loop system outside of the existing Boiler Building. The existing bottom ash trough and sluicing pump would deliver the ash to the new remote dewatering containment with a new submerged chain conveyor that would dewater and deliver the ash to a three-sided bunker for truck removal.

Refer to Drawing 190507-PFD-4006 for the material flow. Table 4-4 outlines the estimated cost. The major equipment for this alternative includes the following:

- Existing bottom ash trough and existing grinders.
- Existing sluice pumps but may need a booster pump if located a long distance from the Boiler Building.
- New remote hopper with new submerged chain conveyor for dewatering.
- Hydraulic power unit.
- PLC control system and instrumentation.
- MCC to feed new motors and pumps.
- Chain wash spray.
- Return water pumps and piping.

Key comparisons for Alternative 3 include the following:

- Disadvantages of the remote closed loop system:
  - A new foundational support for the remote equipment is required.
  - Weather protection for remote collection trough is required.
  - A weather protection structure may be required to control the ash in the three-sided concrete containment structure.
  - Freeze protection is required for winter operation.
  - More expensive new equipment is required, especially if the remote system is located so far away that a booster pump is required to deliver the wet ash.
  - Ash sluicing water must be 100 percent accounted for and maintained in a closed loop or treated prior to discharge.
- Advantages of the remote closed loop system:
  - No outage time is required for modification of the existing boiler.

2.4.3 Fly Ash

A.B. Brown utilizes dry ash handling a majority of the time for beneficial reuse, but resorts to wet fly ash handling when beneficial reuse transport is unavailable. For the dry fly ash system, the low-pressure ash pond water is used to draw a vacuum on various ash hoppers through the hydroveyor and move the fly ash to a filter/separator that is then pressurized and blows the ash to a storage silo near the river for barge loading. For sluicing the wet fly ash, the vacuum portion does not change but the ash is dropped into a combine tube prior to reaching the filter/separators that mixes it with water and moves it to the ash pond for storage when the dry fly ash storage silo is full.

When the ash pond is closed, the source of water for the vacuum will be lost, and the ability to wet the fly ash and move it to the ash pond will be lost. To solve the loss of the vacuum source, a new mechanical exhauster system will be required. Essentially these are vacuum pumps that will use the existing infrastructure to replace the hydroveyor. The ash will still be pulled from the ash collection hoppers to the filter/separator system for pressurized transport to the existing dry fly ash storage silo and new day bin silo. F.B. Culley Station purchased (from UCC), installed, and has been operating mechanical exhausters for several years. The technology and product have proven to be reliable. A.B. Brown has identified the same vendor and equipment to perform a similar function.

Currently the dry fly ash storage silo is located near the river and accepts the pneumatically conveyed ash from the A.B. Brown units as well as trucked ash from F.B. Culley and Warrick. This silo has equipment for pneumatically unloading tank trucks into the silo and a tube conveyor for moving ash to the river for barge loading from the silo. However, it does not have equipment for loading over-the-road trucks for transport of dry fly ash.

New mechanical exhausters and a day bin silo have been identified for installation at the plant site instead of at the river silo area to take advantage of the auxiliaries available for cost reduction. The day bin silo would be a smaller silo with a paddle mixer (pug mill) to wet the ash to control fugitive dust and would be capable of loading into over-the-road trucks. The fly ash handling equipment cost estimate is included in Table 4-4.

2.5 A. B. BROWN--IMPACT OF ELG REGULATIONS

The critical aspect of this review is the impact these regulations will have on the wastewater point source discharges at A.B. Brown. Black & Veatch’s scope of work for this review was to identify the target areas for specific pollutants that are included in the final ruling and determine which wastewater discharge streams, if any, are affected by the updated ELG regulations.

Of the new wastewater streams regulated under the EPA’s revised rule, only fly ash transport, bottom ash transport, low volume wastewater, and leachate apply to A.B. Brown. The EPA and IDEM have determined that the dual alkali scrubber discharge wastewater at A.B. Brown, as it is defined in the 2015 ELG rulemaking, is not subject to the FGD standards in the ELG rule. The EPA established numerical effluent limits that would correspond to the level of treatment that could be achieved based on application of these treatment technologies. While the scrubber wastewater is not subject to ELG standards, the current NPDES permit contains final effluent limitations for copper, selenium, and chloride.

Wastewater at A.B. Brown is considered direct discharge from an existing source. The current ELGs for the steam electric power generating existing sources and their applicability to A.B. Brown are shown in Appendix A.

2.5.1 Operation Evaluation

A.B. Brown currently utilizes sluicing systems to transport fly ash and bottom ash to the ash pond for settling. The EPA's final rule on wastewater effluent regulation standards requires zero discharge for fly and bottom ash transport water (refer to Table 2-1). For fly and bottom ash transport, the final ELG rule specifies dry handling or closed-loop systems as the technology basis.

The removal of ash sluice water and closure of the ash pond would comply with the CCR rule requirements. All waste streams currently discharged to the ash pond were sampled to determine water quality. The sampled waste stream data indicate that A.B. Brown is expected to achieve the new direct discharge limits from an existing source imposed by the final rule if the settling capability of the ash pond were to be sufficiently substituted.

2.6 A.B. BROWN--TECHNOLOGY OPTIONS FOR ELG/NPDES COMPLIANCE

Based on review of the final ELG, NPDES permit, and capabilities of the existing plant wastewater systems to achieve these standards, Black & Veatch has identified potential modifications to the existing wastewater system as well as additional treatment that could be implemented to comply with wastewater effluent limitations. A summary and breakdown of the conceptual cost estimate can be found in Section 4.0.

2.6.1 Ash Pond Elimination

Elimination of the ash pond represents a significant reduction in reuse water, storage, and settling capabilities for A.B. Brown. Ash sluice water and FGD makeup are the major consumers of reuse water and sources of wastewater. The pending ash pond closure and conversion to a closed loop SCC for bottom ash handling represents a large reduction in wastewater generation and storage requirements, which would minimize the size of any downstream treatment equipment. However, the new treatment equipment would still need to be capable of handling approximately 2.5 million gallons per day (mgd) of treated low volume wash water streams from FGD wash water and coal pile runoff.

It is important to note that the FGD wash water is not an FGD wastewater as defined in the ELG rule. The 2015 ELG rule added the following clarifying sentence to the definition of FGD wastewater:

"Wastewater generated from cleaning the FGD scrubber, cleaning FGD solids separation equipment, cleaning FGD solids dewatering equipment, or that is collected in floor drains in the FGD process area is not considered FGD wastewater."

Therefore, the dual alkali scrubber does not discharge FGD wastewater as it is defined in the ELG rule, and the scrubber is not subject to the FGD ELG standards.

While this report focuses on ELG compliance, elimination of the ash pond will impact NPDES permit compliance. Therefore, final effluent limitations for parameters such as copper, chloride and selenium, are being considered in evaluation of treatment options. Treatment options evaluated for compliance with the ELG rule (and NPDES permit) include physical/chemical treatment, settling and dewatering processes, and CCR compliant basins or tanks for reduction of suspended solids.

2.6.2 Design Concept

The basic design concept includes treating scrubber wastewater and collecting and re-directing all existing flows that discharge to the ash pond. Collected wastewater would be transferred to the necessary users for reuse demands with the accumulated wastewater. Water not reused would be filtered and transferred to the existing wastewater mercury treatment system and subsequent lined pond. The basic design concept would still utilize a significant portion of the existing equipment while providing a physical/chemical/biological system for heavy metals and suspended solids reduction, a basin for collection and flow equalization, a filter system for final suspended solids reduction in the combined basin wastewater, and a sludge dewatering system for solids handling and removal.

Using A.B. Brown's water qualities and a water mass balance provided by Vectren, Black & Veatch developed a proposed water mass balance outlining influent and effluent flows around pieces of equipment impacted by the pending closure. Black & Veatch's proposed water mass balance is contained in Appendix D.

2.6.3 FGD Treatment

2.6.3.1 Physical/Chemical Treatment

Physical/chemical treatment is a process used for heavy metals and total suspended solids (TSS) reduction. On the basis of the effluent limitations identified in the current NPDES permit, the heavy metals of concern are mercury, copper, and selenium. To achieve the desired level of metals removal and TSS reduction, the FGD blowdown would be pumped to a new continuously mixed sulfide reaction tank, followed by a coagulation reaction tank, to allow for chemical addition of organosulfide and coagulant. An organosulfide would be fed to achieve high removal of heavy metals by converting the soluble metals to an insoluble precipitate.

The reaction tanks are sized to allow sufficient reaction time for the chemical precipitation reactions to occur. The reaction tanks feed a clarifier where polymer is added to increase the particle size of the insoluble particles and allow settling for solids removal with traditional clarification techniques. Settled solids from clarification would be directed to dewatering equipment. While the physical/chemical treatment will reduce mercury and copper in the FGD wastewater, additional treatment will be required to reduce selenium.

2.6.3.2 Biological Treatment

Selenium typically exists in one of two forms, selenite (Se^{+4}) or selenate (Se^{+6}), which are both soluble in water. Selenite can typically be removed from wastewater through chemical precipitation, where selenate is more soluble, requiring reduction to a less soluble form for removal. Selenium in FGD wastewater typically exists in both forms and the concentration of each form depends on plant operation and the type of coal being combusted. Therefore, a biological treatment process is required downstream of the physical/chemical treatment system to reduce selenium.

Anaerobic biological treatment is an industry-proven technology for selenium and is the basis for the ELG limits. Biological treatment involves the growth of naturally occurring microorganisms that act as selenium reducing agents. A food source (nutrient) is oxidized by the microorganisms, which in turn reduces both selenate and selenite and precipitates solid elemental selenium. Biological treatment typically consists of a series of fixed-film biofilters in a controlled, anaerobic environment for the proper reactions and reduction of selenium to occur.

Periodically, biomass and elemental selenium are backwashed from the system. During backwash, treated effluent is used as a counterflow wash to remove entrained solids and gases from the biofilter substrate. Backwash wastewater is allowed to degas and is recycled to the inlet of the secondary pretreatment system where the solids are settled in the clarifier and dewatered with the pretreatment sludge. The treated water is discharged downstream to the collection basin for storage and use within the facility.

2.6.3.3 Sludge Handling

Accumulated sludge from the clarifier is collected in a sludge holding tank. The sludge holding tank is sized to hold 12 hours of sludge accumulation. Two 100 percent capacity filter press feed pumps supply sludge from the holding tank to two 100 percent capacity recessed plate and frame filter presses that dewater the sludge. Sludge conditioning polymer, supplied from a chemical tote, is fed upstream of the filter presses to improve dewatering. Dewatered solids can be deposited in the landfill at A.B. Brown. Removal of solids provides further metals reduction.

2.6.4 Collection Basin

A concrete, below grade collection basin will serve the purpose of equalizing wastewater flow rates from the coal pile runoff pond and treated effluent from the new FGD treatment system. The collection basin will provide a reservoir from which to draw reuse water to supply existing high-pressure water recirculation users and makeup water for dry bottom ash system. The collection basin is sized to accommodate 20 minutes of retention time for all flows indicated on the water mass balance. A mixer is included with the collection basin to prevent the settling and accumulation of solids within the collection basin.

Two 100 percent capacity, vertical sump pumps will draw suction from the collection basin to supply existing users of high-pressure ash pond recirculation pumps. New piping from the collection basin will tie into existing high-pressure water piping. Additional piping will be included to direct recirculation water as cooling makeup water for dry bottom ash system from the high-pressure recirculation supply pumps.

While TSS reduction occurs in the upstream FGD treatment system, the combined wastewater in the collection basin will have increased TSS levels because of the contribution from the untreated coal pile runoff pond discharge. To meet the NPDES permit limits for TSS, a new filter system will be installed on the discharge from the collection basin. Two 100 percent capacity discharge pumps controlled based on level in the collection basin will forward wastewater from the collection basin to the filter system for suspended solids removal. Periodically, the filter system is backwashed to remove accumulated solids. The backwash waste stream will be discharged to the sludge handling system further thickening and dewatering prior to disposal. Filtered water is sent to the existing Ash Pond Mercury Treatment System, existing lined settling pond, and finally to Outfall 001.

2.6.5 Operations and Maintenance Costs of A.B. Brown NPDES Compliance

Black & Veatch has developed estimated costs for the operations and maintenance (O&M) of the proposed treatment. Costs include consumption of chemical feeds, cost to dispose of solids, power consumption, and staffing costs. The O&M costs are presented in Section 4.0.

2.7 F.B. CULLEY--IMPACT OF CCR REGULATIONS

The F.B. Culley facility has two CCR units: the east and west. The west pond is now an inactive surface impoundment undergoing closure. The east pond is an active pond. The elimination of CCR units represents a significant reduction in storage and settling capabilities for F.B. Culley.

2.8 F.B. CULLEY--TECHNOLOGY OPTIONS FOR CCR COMPLIANCE

Black & Veatch worked with Vectren to evaluate different cost-effective concepts of bottom ash handling at F.B. Culley Unit 2. These alternatives focus on meeting the ELG regulations by converting the bottom ash system either to a dry system or a closed loop wet system. Each alternative proposed will allow the bottom ash to be dewatered sufficiently and truck transported off-site.

Following the evaluation, Black & Veatch recommended incorporation of a dewatering tank system for F.B. Culley Unit 2. A project is currently in progress to install the SCC at F.B. Culley Unit 3 with installation scheduled for 2020. The installed cost to retrofit the F.B. Culley Unit 2 boiler with dewatering tank equipment has been incorporated into the treatment options in Section 4.0, Table 4-4.

A technology comparison matrix for the bottom ash alternatives described for F.B. Culley Unit 2 is provided in Table 2-3.

Table 2-3 F.B. Culley Unit 2 Bottom Ash Technology Comparison Matrix

ALTERNATIVE	BUCKET ELEVATOR (ALTERNATIVE 1)	INDOOR DEWATERING TANKS (ALTERNATIVE 2)	DRY PNEUMATIC SYSTEM (ALTERNATIVE 3)	REMOTE SUBMERGED CHAIN CONVEYOR (ALTERNATIVE 4)
Description	Alternative 1 utilizes a new vertical bucket elevator connected under the existing ash trough at the existing grinder discharge. The bucket elevator concept will dewater the material as the ash is raised above the water level.	Alternative 2 delivers the bottom ash from the existing ash trough through the existing pumps to a dewatering tank located on the operating floor near the northeast corner of the Boiler Building. The new dewatering tank will require properly sized filters or screens to separate the water from the bottom ash. The separated water would be recycled back to the existing bottom ash trough. The dewatering tank will discharge bottom ash into a container for a forklift to haul outside of the building. Once outside the Boiler Building, the material can be loaded into trucks for transport off-site.	Alternative 3 is a completely dry system but will require an entirely new dry bottom ash trough and a new exterior dry hopper storage bin. The replacement of the existing bottom ash trough will be a major construction effort requiring a long outage for the unit. There are various options to collect the ash at the bottom of the new trough such as a vacuum conveyor, a vibratory oscillatory conveyor, or a mesh screen drag conveyor.	Alternative 4 provides a remote closed loop system outside of the existing Boiler Building. The existing bottom ash trough and sluicing pump would deliver the ash to the new remote dewatering containment with a new submerged chain conveyor that would dewater and deliver the ash to a three-sided bunker for truck removal.
Technical Feasibility	This concept utilizes a bucket elevator for dewatering, which is rarely used in the power industry. The design would need thorough investigation to ensure the elevator will handle the fines in the allotted space. As well as assurance that the wet ash would discharge from the bucket effectively. Based on the highly conceptual nature of the design and lack of industry specific equipment available, this option was determined technically not feasible.	This concept of using dewatering tanks has been used in the past. Further design refinement will be required to determine if one or two tanks are necessary to accomplish complete dewatering.	Dry bottom ash troughs are being used in the industry but usually they are intended for larger boilers with more height. Special design will be required to fit the troughs in the shallow height of Unit 2.	Remote recirculation systems are often used for bottom ash conversions. The technical feasibility is sound but may not be financially viable for small units.
Total Contracted Cost	NA	$3,868,000	$7,636,600	$17,059,600
Operations and Maintenance Cost	NA	$300,300	$311,100	$471,000
Estimated Manpower	0.4	0.4	0.4	0.8
Est. Footprint (sq. ft.)	400	1,000	2,000	6,000
Major Equipment	• Vertical bucket elevator. • Hydraulic power unit. • Instrumentation and controls. • Forklift container. • Quench water overflow tank, pumps, separator, and heat exchanger. • MCC to feed new motors and pumps.	• Distribution piping. • Dewatering tank. • Quench water overflow tank, low- and high-pressure pumps, and heat exchanger. • Instrumentation and controls. • Forklift container. • MCC to feed new motors and pumps.	• New dry trough and conveyor. • New grinders. • Pneumatic power unit. • Exterior dry storage tank. • Wet conditioning equipment. • Instrumentation and controls • MCC to feed new motors and pumps.	• Remote submerged chain conveyor. • Hydraulic power unit. • Quench water overflow tank and pump. • Instrumentation and controls. • Recycle water pumps and piping. • Chain wash spray system. • Distribution sluice piping. • MCC to feed new motors and pumps.
Advantages	• Minimal new equipment. • Utilizes the existing bottom ash trough. • Outage time minimized if foundation modifications can be completed prior to outage.	• Lowest comparative capital costs. • Allows for continued use of existing ash trough, grinders, and jet pumps. • Minimal outage time required.	• Quench water removed from system, but still may require water for a wet conditioner system for loading open top trucks.	• Minimal outage time required for modification of the existing boiler. • Cost prohibitive for a small unit; but may show financial benefit if utilized for multiple units.
Disadvantages	• Requires a larger pit to be excavated in the existing ground floor of the Boiler Building. • The use of a bucket elevator as a dewatering device is rare and will require additional design refinements and coordination with the equipment supplier. • The ash discharged from the bucket elevator may not be completely dewatered due to the equipment and space constraints. Additional dewatering may be required after the bottom ash prior to truck loading.	• Water from the dewatering tank and forklift container must be recycled in a closed recirculating loop back to the existing bottom ash trough. • The water tank may require special internal screens to dewater sufficiently. Laboratory tests may need to be conducted to ensure this design. • If the dewatering tank is located outside the equipment and piping will require heat trace and insulation for winter operation.	• Requires a lengthy outage period to replace the existing bottom ash trough. • Major modification to boiler requiring expensive new equipment.	• Requires new foundations for remote equipment. • Requires weather protection for the collection trough. • Requires a three-sided concrete containment structure with weather protection. • Requires freeze protection. • Requires lengthy sluice piping. • Ash sluicing water maintained in a closed loop or treated prior to discharge.
Reliability	The reliability of the bucket elevator is dependent on the ability to properly dewater. Since this is not	The dewatering tanks are a proven approach to bottom ash dewatering.	Dry pneumatic ash handling is a proven approach for large units.	Remote recirculation systems are often used for bottom ash conversions.

ALTERNATIVE	BUCKET ELEVATOR (ALTERNATIVE 1)	INDOOR DEWATERING TANKS (ALTERNATIVE 2)	DRY PNEUMATIC SYSTEM (ALTERNATIVE 3)	REMOTE SUBMERGED CHAIN CONVEYOR (ALTERNATIVE 4)
	a common use of bucket elevators, the reliability is difficult to predict.			
Recommended for Further Review	No	Yes	No	No

2.8.1 Existing System and Conceptual Design Basis

The bottom ash system will be designed to receive bottom ash from the existing Unit 2, 100 MW pulverized coal fired unit.

The existing ash collection hopper consists of one longitudinal hopper with one clinker grinder mounted at the west end. The hopper is located in the basement area of the Boiler Building while the operating floor is 37 feet above the basement. The east side of the operating floor exits at the grade level, while the west side is over the one story Administration Building. The longitudinal bottom ash hopper has three segments with flat bottoms that are stair-stepped in elevation toward the grinder. Jet pumps located at the discharge of the clinker grinder and jet pump piping located at each step-in elevation are used to sluice the bottom ash from the bottom ash hopper to the bottom ash storage pond. The existing hopper cooling water overflows from the bottom ash hopper by gravity to an existing plant drain.

The conceptual design for this study is based on a maximum ash production rate of 1 ton per hour.

2.8.2 Bottom Ash Conceptual Design Alternatives

The following conceptual design alternatives were developed for F.B. Culley Units 2.

2.8.2.1 Bucket Elevator (Alternative 1)

The proposed bucket elevator bottom ash system utilizes a new vertical bucket elevator connected under the existing ash trough at the existing grinder to transport bottom ash away from the existing bottom ash hopper. The bucket elevator will dewater the bottom ash as it lifts it up above the ash flush water level to a waiting container on the basement floor. The existing water level in the ash hopper is approximately 8 feet above the basement floor, while the water level during ash flushing is approximately 2 feet above the basement floor.

The bucket elevator will need at least a 4 foot height above the water level to support adequate dewatering. The elevator requires another 2 feet above this point for the head pulley and drive. Therefore, the total minimum length for the bucket elevator above the basement floor must be 14 feet. There appears to be a number of existing pipes approximately 8 feet above the basement floor in this area that must be rerouted. It is assumed this arrangement is workable and will be refined during final design.

In addition, a sloped transition chute to slide the ash out of the grinder and into the elevator must be provided to properly load the bucket elevator. Therefore, it is estimated that the bottom of the bucket elevator will be a minimum of 5 feet below the basement floor. The existing grinder pit is only 3 feet deep.

After the ash is dewatered, the bucket elevator will discharge into a forklift-sized container. The container could be a large manual wheelbarrow, a customized container for a motorized wheelbarrow, or a container designed for a forklift. This type of container can be moved across the basement floor to the existing exterior door in the southwest corner of the Boiler Building; the bottom ash can then be transported with a dump truck to a new landfill.

Because the new bucket elevator system no longer utilizes the ash quench water in the sluicing operation, it will be required to capture and recycle the quench water in a closed loop back to the bottom ash hopper. The ash quench water recycle system would consist of a quench water overflow tank that is gravity-fed from a new bottom ash hopper overflow connection. This tank would be sized so that it can hold all the ash quench discharged over the duration of the bottom ash removal operation. After the bottom ash flush operation is complete, the flush water would then be pumped back to the hopper via a new quench water recycle pump. However, before the water can enter the hopper it may be necessary to both remove some of the bottom ash fines in a separator and cool the water in a heat exchanger. The need for the quench water system separator and heat exchanger will require additional investigation and potential testing during the next phase.

Drawing 190507-PFD-4000 shows a simplified material flow block diagram for the bucket elevator bottom ash system concept. The major equipment for this alternative includes a vertical bucket elevator, hydraulic power unit, bottom ash container, ash flush water recirculation system, instrument and controls, new MCC, and mobile equipment to move the ash (e.g., forklift, dump truck).

The most critical issue with this alternative is the ability to properly load the bucket elevator in a manner that will not overload the buckets. To prevent possible plugging of the individual buckets, the elevator must operate continuously while the ash trough is evacuated; otherwise, fine material will build up around the tail pulley and overfill the lower section of the elevator with compacted fines.

Other concerns may be the fines that tend to float because the water level in the bucket elevator will be level with the water in the bottom ash trough. The water level is 12 to 14 feet above the bottom of the vertical elevator. If the buckets are traveling at an inappropriate speed, the floating material may spill over the edge of the buckets.

In conclusion, the bucket elevator design is sensitive to the proper sizing of the buckets and the number of dewatering openings, combined with the speed at which the buckets travel. All of these factors must match the actual physical properties of the bottom ash to ensure dewatering over the travel height of the elevator. Based on the highly conceptual nature of the design and lack of industry specific equipment available, this option was determined technically not feasible.

Key comparisons for Alternative 1 include the following:

- Disadvantages of vertical elevator:

- It requires an excavated large pit of approximately 8 feet by 8 feet by 5 feet in the existing foundation to allow for proper loading of the bottom ash into the bucket elevator. This will require extensive foundation modification.
- There will be a design balance between elevator speed and material density, possibly requiring laboratory scale testing to finalize the design. Also, an additional pump will be required to remove the flush water in the excavated pit. The new pump may also draw some bottom ash fines. Therefore, a filter/separator may be inserted to assist in removing these fines before the water is recycled.
- The use of a bucket elevator to dewater bottom ash is rare; it will require buckets with screen material to accomplish dewatering. The lower portion of the elevator will be submerged in water. The number and size of dewatering holes in the buckets must match the properties of the actual ash produced at the plant. If, during the final design phase, it is found that the bucket elevator cannot effectively load the ash, other options within this alternative could be a screw conveyor or drag chain.
- The bucket elevator may have difficulty starting because of the settlement of ash fines around the tail end pulley. If too much ash collects, it may tend to plug/overload the buckets. To help prevent buildup of fines, the bucket elevator may require startup before the bottom ash is flushed from the boiler.
- The ash discharged on the operating floor may not be completely dewatered. A watertight collection hopper/container may also require screens to ensure that, by the time the material is dumped into a dump truck, it is sufficiently dry.

- Advantages of vertical elevator:
  - Minimal new equipment is required.
  - The option allows for the continued use of existing bottom ash hoppers.
  - The installation of equipment requires minimal outage time as long as the foundation modification can be complete without an outage.

2.8.2.2 Indoor Dewatering Tanks (Alternative 2)

Alternative 2 delivers the bottom ash from the existing ash trough through the existing pumps to a dewatering tank located on the operating floor near the northeast corner of the Boiler Building. This new dewatering tank will require properly sized filters or screens to separate the water from the bottom ash. The separated water would be recycled back to the existing bottom ash trough. The dewatering tank will discharge into a container for a forklift to haul outside the building. Once outside the Boiler Building, the material can be dumped into a dump truck.

Depending on the actual physical properties of the bottom ash, the forklift container may also require filters or screens to ensure that the material discharged into the dump trucks is dry.

Refer to Drawing 190507-PFD-4001 for the material flow. Table 4-2 outlines the estimated cost. The major equipment for this alternative includes the following:

- Sluice piping.
- Dewatering tank.
- Overflow tank with recirculation pump(s) and heat exchanger.
- PLC control system and instrumentation.
- MCC to feed new motors and pumps.
- Forklift container, along with the use of a forklift and dump truck.

Key comparisons for Alternative 2 include the following:

- Disadvantages of the dewatering tank:
  - Water from the dewatering tank and forklift container must be recycled in a closed recirculating loop back to the existing bottom ash trough. In the event there is a discharge stream it will require the utilization of a zero liquid discharge treatment. One possible ZLD solution would be the utilization of the spray dry evaporator planned for future installation on F.B. Culley Unit 3.
  - If the dewatering tank must be located outside the existing Boiler Building, the dewatering and the water discharge piping must be heat traced for winter operation. The current assumption is that the tank can be located in the turbine deck area.
  - The water tank may require special internal screens to dewater sufficiently. Laboratory tests may need to be conducted to ensure this design.
  - Ash sluicing water must be 100 percent accounted for and maintained in a closed loop or treated prior to discharge.
- Advantages of the dewatering tank:
  - Minimal new equipment is required because the existing sluice pumps will be enough for reuse.
  - Minimal capital costs are required.

Minimal outage will be needed for installation because much of the existing equipment will be reused.

2.8.2.3 Dry Pneumatic System (Alternative 3)

Alternative 3 is a completely dry system but will require an entirely new dry bottom ash trough and a new exterior dry hopper storage bin. The replacement of the existing bottom ash trough would be a major construction effort and would cause a long outage for the unit. There are various options for collecting the ash at the bottom of the new trough such as a vacuum conveyor, a vibratory oscillatory conveyor, or a mesh screen drag conveyor. The exterior storage bin would require new pneumatic equipment to draw the ash out of the Boiler Building to a location north of the plant. This storage bin would require a sizable foundation because the bin would be elevated to allow unloading the material into either an open truck or a pneumatic tanker truck. If an open truck is used, a wet conditioner may be required to prevent fugitive dust.

Refer to Drawing 190507-PFD-4002 for the material flow. Table 4-2 outlines the estimated cost. The major equipment for this alternative includes the following:

- New dry trough and conveyor.
- New grinders.
- Pneumatic power unit.
- Exterior dry storage tank.
- Possible wet conditioning equipment to load open dump trucks.
- PLC control system and instrumentation.
- MCC to feed new motors and pumps.

Key comparisons for Alternative 3 include the following:

- Disadvantages of pneumatic ash removal:
  - A lengthy outage period is required because existing ash hopper must be removed.
  - Additional equipment for a vacuum conveying system is required.
  - A major amount of expensive new equipment is required.
  - If unloaded to an open truck, a wet conditioning system may be required to control dust. This will affect the water balance for the system.
- Advantages of pneumatic ash removal:
  - It does not require water under the boiler but may still require water for a wet conditioner system under the storage bin to properly load open trucks.

2.8.2.4 Remote Submerged Chain Conveyor (Alternative 4)

Alternative 4 provides a remote closed loop system outside the existing Boiler Building. The existing bottom ash trough and sluicing pump would deliver the ash to the new remote dewatering containment with a new submerged chain conveyor that would dewater and deliver the ash to a three-sided bunker for truck removal.

Refer to Drawing 190507-PFD-4003 for the material flow. Table 4-2 outlines the estimated cost. The major equipment for this alternative includes the following:

- Utilizes existing bottom ash trough and existing grinders.
- Utilizes existing slice pumps but may need a booster pump if located a large distance from the Boiler Building.
- New remote hopper with new submerged chain conveyor for dewatering.
- Hydraulic power unit.

- PLC control system and instrumentation.
- MCC to feed new motors and pumps.
- Chain wash spray.
- Return water pumps and piping.

Key comparisons for Alternative 4 include the following:

- Disadvantages of the remote closed loop system:
  - A new foundational support for the remote equipment is required.
  - Weather protection for the collection trough is required.
  - A weather protection structure might be required to control the ash in the three-sided concrete containment structure.
  - Freeze protection for winter operation is required.
  - More expensive new equipment is required, especially if the remote system is located so far away that a booster pump is required to deliver the wet ash.
  - Ash sluicing water must be 100 percent accounted for and maintained in a closed loop or treated prior to discharge.
- Advantages of the remote closed loop system:
  - No outage time required for modification of the existing boiler.
  - May be cost prohibitive for a small unit; but may show financial benefit if utilized for multiple units.

2.8.3 Fly Ash

The dry ash handling system is already in service at F.B. Culley using mechanical exhausters. The alternative wet sluicing line will need to be capped and abandoned in place so the capability of sluicing fly ash no longer exists to meet compliance.

3.0 Economic Criteria

The economic criteria shown in Table 3-1 was used to develop the cost estimates presented in this report. The present worth discount rate, capital recovery factor, and present worth values listed do not represent Vectren's actual or proposed values. These values represent relative values that have been applied to technology scenarios to determine the most economical alternative. The results of these evaluations are summarized in Section 4.0.

Table 3-1 A.B. Brown ELG Compliance - Summary of Economic Criteria

ECONOMIC INPUTS - ALL UNITS	VALUE	UNITS
Present Worth Discount Rate	6.00	%
Economic Life	20	years
Capital Recovery Factor (Calculated)	8.72	%
Present Worth Factor (Calculated)	11.47	
Salary – Full Time O&M Employee	100,000	$/year
Power Price	0.098	$/kWh
Plant Capacity – Brown Unit 1	65	%
Plant Capacity – Brown Unit 2	65	%
Plant Capacity – Culley Unit 2	25	%
Balance of Plant Treatment (BPT) Reagent-Coagulant Feed (Ferric Chloride)	0.12	$/lb
Organosulfide	1.36	$/lb
BPT Reagent - Flocculant Aid (polymer)	0.60	$/lb
Filter Press Polymer Costs	0.60	$/lb
Selenium Reagent - Sulfuric Acid	0.20	$/lb
Selenium Reagent - Nutrient Feed	1.98	$/lb
Selenium Reagent - Lime	0.10	$/lb
On-site Landfill Costs	24	$/load
On-site Landfill Haul Capacity	30	tons/load
Off-site Landfill Costs	990	$/load
Off-site Landfill Haul Capacity	25	tons/load

4.0 Conceptual Cost Estimate Cases

Tables 4-1 and 4-2 present the ±50 percent cost estimates for A.B. Brown separated into treatment options for CCR and ELG compliance, respectively. Table 4-3 presents the ±50 percent cost estimate for CCR compliance at F.B. Culley. Table 4-4 presents the ±50 percent fly ash cost estimate for A.B. Brown Units 1 and 2. Each scenario presents the capital cost and O&M costs for its respective treatment technologies.

Table 4-1 Cost Estimate Summary for ELG Compliance – A.B. Brown Station

DESCRIPTION	PHYSICAL/CHEMICAL AND BIOLOGICAL TREATMENT
Direct Cost	
Pumps and Drivers	$163,000
Water Treatment - Physical/Chemical	$7,598,000
Water Treatment - Biological	$6,990,000
Water Treatment - Filtration	$222,000
Mechanical Equipment, Piping and Piping Specials	$1,432,000
Electrical Equipment	$3,502,000
Civil/Structural Works	$3,375,000
Total Direct Cost (DC)	**$23,282,000**
Indirect Cost	
Construction Management 20% x DC	$4,657,000
Construction Indirects 15% x DC	$3,492,000
Engineering 15% x DC	$3,492,000
Contingency 20% x DC	$4,657,000
Overhead and Profit 15% x DC	$3,492,000
Total Indirect Cost Including Material and Labor (IC)	**$19,790,000**
Total Direct and Indirect Costs = (DC + IC)	**$43,072,000**
ANNUAL OPERATING COST	
Power	$27,000
Chemical Feed	$906,000
Off-site Landfill Costs	$95,000
Equipment Operator Labor (FTE)	$50,000
Maintenance	$300,000
Total Direct Annual Costs (DAC)	**$1,378,000**

Table 4-2 Summary of Unit 2 F.B. Culley Bottom Ash Cost Estimate (100 MW; 1 tph Ash Production)

DESCRIPTION	BUCKET ELEVATOR	INDOOR DEWATERING TANKS	DRY PNEUMATIC SYSTEM	REMOTE SUBMERGED CHAIN CONVEYOR
Alternative	1	2	3	4
CAPITAL COST **<u>Direct Costs</u>**				
Weather Structure Remote Structures	NA	NA	NA	$213,400
Weather Structure 3-Sided Conc. Contain	NA	NA	NA	$106,700
New Dry Bottom Ash Trough	NA	NA	$1,067,000	NA
Dewatering Tank Support and Access	NA	$426,800	NA	NA
Emergency Drain Tank for Meeting Plant ZLD Requirement	NA	$400,100	NA	NA
Heat Exchanger	NA	$213,400	NA	NA
New Grinders	NA	NA	$853,600	NA
New Exterior Vacuum System	NA	NA	$533,500	NA
New Wet Conditioning for Dump Truck	NA	NA	$213,400	NA
New Remote Wet Trough w/Submerge Chain Conveyor/Overflow Tank	NA	NA	NA	$4,268,000
Vertical Bucket Elevator w/ Drive Unit	NA	NA	NA	NA
Subtotal: Equipment Costs	NA	$1,040,300	$2,667,500	$4,588,100
Electrical, Instr. and Controls Equipment	NA	$233,700	$249,700	$602,900
Mechanical Equipment, Piping and Valves	NA	$266,800	$298,800	$1,760,600
Foundations and Civil Works	NA	-	$266,800	$1,067,000
Miscellaneous Equipment	NA	$277,400	$106,700	-
Demolition Works	NA	$87,200	$393,000	$87,200
Existing BOP System Modifications	NA	$185,400	$145,300	$115,600

DESCRIPTION		BUCKET ELEVATOR	INDOOR DEWATERING TANKS	DRY PNEUMATIC SYSTEM	REMOTE SUBMERGED CHAIN CONVEYOR
Site Earth Works		NA	-	-	$1,000,000
Subtotal: Miscellaneous Costs		NA	$1,050,500	$1,460,300	$4,633,300
Total Direct Costs (DC)		**NA**	**$2,090,800**	**$4,127,800**	**$9,221,400**
Indirect Costs					
Construction Management	20% x DC	NA	$418,200	$825,600	$1,844,300
Construction Indirects	15% x DC	NA	$313,600	$619,200	$1,383,200
Engineering	15% x DC	NA	$313,600	$619,200	$1,383,200
Contingency	20% x DC	NA	$418,200	$825,600	$1,844,300
Overhead and Profit	15% x DC	NA	$313,600	$619,200	$1,383,200
Total Indirect Costs (IC)		**NA**	**$1,777,200**	**$3,508,800**	**$7,838,200**
Total Contracted Costs (CC) DC + IC		**NA**	**$3,868,000**	**$7,636,600**	**$17.059.600**
ANNUAL OPERATING COST **Operating Costs**					
Power		NA	$38,300	$14,300	$42,900
Off-site Landfill Costs		NA	$182,300	$182,300	$182,300
Equipment Operator Labor (FTE)		NA	$42,700	$42,700	$85,400
Maintenance		NA	$37,000	$71,800	$160,400
Total Direct Annual Costs (DAC)		**NA**	**$300,300**	**$311,100**	**$471,000**

Table 4-3 Summary of Units 1 and 2 A.B. Brown Bottom Ash Cost Estimate (265 MW each; 3 tph Ash Production)

DESCRIPTION	SUBMERGED CHAIN CONVEYOR (1)	DEWATERING BUNKER (1)	REMOTE SUBMERGED CHAIN CONVEYOR (1)
Alternative	1	2	3
CAPITAL COST **Direct Costs**			
Weather Structure for Remote System	NA	$426,800	$4,300,000
Weather Structure for 3-Sided Conc. Storage	$406,200	NA	$406,200
Dewatering Bunker/Sump	NA	$853,600	NA
Settling and Surge Tanks	NA	$2,500,000	$373,500
Submerged Chain Conveyor	$5,000,000	NA	NA
Bottom Ash Tank w/Jet Pump and Water Supply Tank	NA	$917,600	NA
Sluice, Recirculation and Sump Pumps	NA	$3,128,400	NA
Seal Water Pumps	NA	$640,200	NA
New Remote Wet Trough w/Submerge Chain Conveyor/Overflow Tank	NA	NA	$5,400,000
Mechanical Pump and Piping Modification	NA	$320,100	$1,600,500
Subtotal: Equipment Costs	$5,406,200	$8,786,700	$12,080,200
Electrical, Instrumentation and Controls Equipment	$2,942,800	$1,557,800	$2,500,000
Mechanical Equipment, Piping and Valves	$3,776,900	$3,190,300	$3,000,000
Foundations and Civil Works	$1,941,100	$3,000,000	$2,000,000
Miscellaneous Equipment Installation	-	$597,500	-
Demolition Works	$1,454,000	$440,000	$440,000
Existing BOP System Modifications	$655,900	$379,900	$646,900

DESCRIPTION		SUBMERGED CHAIN CONVEYOR (1)	DEWATERING BUNKER (1)	REMOTE SUBMERGED CHAIN CONVEYOR (1)
Site Earth Works		-	$1,750,000	1,850,000
Subtotal: Miscellaneous Costs		$10,770,700	$10,915,500	$10,436,900
Total Direct Costs (DC)		**$16,176,900**	**$19,702,200**	**$22,517,100**
Indirect Costs				
Construction Management	20% x DC	$3,235,400	$3,940,400	$4,503,400
Construction Indirects	15% x DC	$2,426,500	$2,955,300	$3,377,600
Engineering	15% x DC	$2,426,500	$2,955,300	$3,377,600
Contingency	20% x DC	$3,235,400	$3,940,400	$4,503,400
Overhead and Profit	15% x DC	$2,426,500	$2,955,300	$3,377,600
Total Indirect Costs (IC)		**$13,750,300**	**$16,746,700**	**$19,139,600**
Total Contracted Costs (CC)	**DC + IC**	**$29,927,200**	**$36,448,900**	**$41,656,700**
ANNUAL OPERATING COST **Operating Costs**				
Power		$22,300	$89,200	$126,300
Off-site Landfill Costs		$946,100	$946,100	$946,100
Equipment Operator Labor (FTE)		$192,100	$384,100	$256,100
Maintenance		$100,000	$120,000	$135,000
Total Direct Annual Costs (DAC)		**$1,260,500**	**$1,539,400**	**$1,463,500**

Note 1: Costs in the Table 4-3 are provided as a total cost for both A.B. Brown Unit 1 and Unit 2.

Table 4-4 Summary of Units 1 and 2 A.B. Brown Fly Ash Cost Estimate

DESCRIPTION		DILUTE PHASE, VACUUM PNEUMATIC CONVEYING SYSTEM
Direct Cost		
Civil and Structural Costs		$5,439,300
Mechanical Costs		$4,328,000
Electrical and Control Costs		$2,477,100
Total Direct Cost (DC)		**$12,244,400**
Indirect Cost		
Construction Indirects	15% x DC	$1,836,700
Engineering	15% x DC	$1,836,700
Construction Management	20% x DC	$2,448,900
Contingency	20% x DC	$2,448,900
Overhead and Profit	15% x DC	$1,836,700
Total Indirect Cost Including Material and Labor (IC)		**$10,407,900**
Total Contracted Costs (CC)	**DC + IC**	**$22,652,300**
ANNUAL OPERATING COST **Operating Costs**		
Power		$37,200
Offsite Landfill Costs		$3,574,400
Equipment Operator Labor (FTE)		$42,700
Maintenance		$25,000
Total Direct Annual Costs (DAC)		**$3,679,300**

5.0 Conclusions and Recommendations

The analysis covered by this comprehensive report has shown ash pond closure options and alternative ash handling and water treatment options to bring A.B. Brown and F.B. Culley Stations into future compliance with the updated CCR and ELG regulations (NPDES compliance). Flue gas desulfurization wastewater treatment for heavy metals and suspended solids reduction will be required at A.B. Brown.

Recommendations for each station are summarized below with associated cost estimates shown in Tables 5-1 and 5-2.

5.1 A.B. BROWN

Based on the evaluations reported in Sections 2.3 through 2.6, Black & Veatch recommends the following:

- **Submerged Chain Conveyor for Bottom Ash Removal**. The modified SCC is technically feasible with less modification to existing equipment and reduced outage time.
- **Mechanical Exhausters for Fly Ash Removal**. The mechanical exhausters match the design at F.B. Culley.
- **Scrubber Treatment and Collection Basin**. The recommended location for the basin and equipment is south of the capital pond. This option avoids expensive impacts to the railway, undergrounds, and is in close proximity to the power block.

5.2 F.B. CULLEY

Based on the evaluations reported in Sections 2.7 through 2.8, Black & Veatch recommends the following:

- **Indoor Dewatering Tanks for Bottom Ash Removal.** The indoor dewatering tank is technically feasible and is a proven approach to bottom ash dewatering and ash removal.

Table 5-1 Summary of Recommended Technologies – A.B. Brown Station

OPTION	TECHNOLOGY DESCRIPTION	CAPITAL COST	O&M COST
ELG Equipment (Table 5-2)	Physical/Chemical and Biological, Collection and Filtration, Location 2	$43,072,000	$1,378,000
Bottom Ash	Modified SCC Bottom Ash Handling	$29,927,200	$1,260,500
Fly Ash	Dry Pneumatic Fly Ash Handling	$22,652,300	$3,679,300

Table 5-2 Summary of Recommended Technologies – F.B. Culley Station

OPTION	TECHNOLOGY DESCRIPTION	CAPITAL COST	O&M COST
Wet-to-Dry Ash Handling	Indoor Dewatering Tanks	$3,868,000	$300,300

Appendix A. Applicable Effluent Guidelines and Standards

WASTE STREAM/POLLUTANT	EXISTING SOURCE DIRECT DISCHARGE		APPLICABILITY A.B. BROWN
	BPT[(a)]	BAT[(a)]	
All Waste Streams	pH: 6-9 S.U. PCBs[(b)]: Zero Discharge.	PCBs: Zero Discharge.	Yes
Low Volume Wastes	TSS: 100 ppm[(1)] / 30 ppm[(2)]. Oil & Grease: 20 ppm[(1)] / 15 ppm[(2)].		Yes
Flue Gas Desulfurization (FGD) Wastewater	TSS: 100 ppm[(1)] / 30 ppm[(2)]. Oil & Grease: 20 ppm[(1)] / 15 ppm[(2)].	Arsenic: 11 ppb[(1)] / 8 ppb[(2)]. Mercury: 788 ppt[(1)] / 356 ppt[(2)]. Nitrate/Nitrite as N: 17 ppm[(1)] / 4.4 ppm[(2)]. Selenium: 23 ppb[(1)] / 12 ppb[(2)].	No[(c)]
Flue Gas Mercury Control (FGMC) Wastewater	TSS: 100 ppm[(1)] / 30 ppm[(2)]. Oil & Grease: 20 ppm[(1)] / 15 ppm[(2)].	Zero Discharge.	No
Gasification Wastewater	TSS: 100 ppm[(1)] / 30 ppm[(2)]. Oil & Grease: 20 ppm[(1)] / 15 ppm[(2)].	Arsenic: 4 ppb[(1)]. Mercury: 1.8 ppt[(1)] / 1.3 ppt[(2)]. Selenium: 453 ppb[(1)] / 227 ppb[(2)]. TDS: 38 ppm[(1)] / 22 ppm[(2)].	No
Combustion Residual Leachate	TSS: 100 ppm[(1)] / 30 ppm[(2)]. Oil & Grease: 20 ppm[(1)] / 15 ppm[(2)].	TSS: 100 ppm[(1)] / 30 ppm[(2)]. Oil & Grease: 20 ppm[(1)] / 15 ppm[(2)].	No
Fly Transport	TSS: 100 ppm[(1)] / 30 ppm[(2)]. Oil & Grease: 20 ppm[(1)] / 15 ppm[(2)].	Zero Discharge.	Yes
Bottom Ash Transport	TSS: 100 ppm[(1)] / 30 ppm[(2)]. Oil & Grease: 20 ppm[(1)] / 15 ppm[(2)].	Zero Discharge.	Yes
Once-Through Cooling	Free Available Chlorine: 0.5 ppm[(3)] / 0.2 ppm[(4)].	Total Residual Chlorine if ≥25 MW: 0.2 ppm[(5)]. If ≤25 MW: equal to BPT.	No
Cooling Tower Blowdown	Free Available Chlorine: 0.5 ppm[(3)] / 0.2 ppm[(4)].	Free Available Chlorine: 0.5 ppm[(3)] / 0.2 ppm[(4)]. 126 Priority Pollutants: Zero discharge except: Chromium: 0.2 ppm[(3)] / 0.2 ppm[(4)]. Zinc: 1.0 ppm[(3)] / 1.0 ppm[(4)].	Yes
Coal Pile Runoff	TSS: 50 ppm[5].		Yes
Chemical Metal Cleaning Wastes	TSS: 100 ppm[(1)] / 30 ppm[(2)]. Oil & Grease: 20 ppm[(1)] / 15 ppm[(2)]. Copper, total: 1 ppm[(1)] / 1 ppm[(2)]. Iron, total: 1 ppm[(1)] / 1 ppm[(2)].	Copper: 1.0 ppm[(3)] / 1.0 ppm[(4)]. Iron: 1.0 ppm[(3)] / 1.0 ppm[(4)].	Yes

Source: [40 CFR Part 423]
[(1)]Maximum concentration for any one day.
[(2)]Average daily values for 30 consecutive days.
[(3)]Maximum concentration.
[(4)]Average concentration.
[(5)]Instantaneous maximum.

[(a)]The pH of all discharges, except once-through cooling water, shall be within the range of 6.0 – 9.0. For all effluent guidelines, where two or more waste streams are combined, the total pollutant discharge quantity may not exceed the sum of allowable pollutant quantities for each individual waste stream. BAT, BPT, NSPS allow either mass or concentration-based limitations.
[(b)]Polychlorinated biphenyl compounds (PCBs) commonly used in transformer fluid.
[(c)] The EPA has ruled that the type of wet FGD system utilized at ABB, dual alkali scrubber, produces only low volume wastewater.
BPT – Balance of Plant Treatment
BAT – Best Achievable Technology

Appendix B. List of Assumptions for A.B. Brown

The conceptual cost estimate is provided for alternative treatment options for each stream that discharges into the ash pond to bring A.B. Brown into compliance with ELG regulations. The A.B. Brown site includes existing coal fired plants.

The cost estimate is based on the assumptions in the following sections:

B.1 GENERAL ASSUMPTIONS

- Ash pond will be closed in place. No costs associated with its closure are included in the estimate.
- All underground pipe will be buried so that the top of pipe is below frost depth. All aboveground pipe will be supported on sleepers.
- Pipe that is running under an existing rail track is assumed to be jack and bored into place.
- Existing buried pipe under 12 inches that will no longer be in service will be capped and abandoned in place. Existing pipe greater or equal to 12 inches will be backfilled. An allowance is also included to remove some large bore piping when in the area of installation of any new piping. No other demolition of any existing structures is included.
- Existing soil will have sufficient strength to support the new basins and building. Cost is added to include a geotechnical survey to confirm this assumption.
- No cost is included for existing gravel road repair or new roads.
- One railroad crossing would be required for Option 2 for new access road.
- A liner was assumed to be needed under collection basin and settling basins. A liner was not assumed to be needed under new piping.
- A new 80 foot by 50 foot metal building with heating, ventilating, and air conditioning (HVAC) is included for new water treatment equipment. A 2 foot thick slab was assumed to be sufficient to support any equipment needed inside the metal building. Piles are not included. There are 2 tons of support steel for miscellaneous equipment inside of the metal building.
- A 2.5 ton jib crane is included for the settling basin.
- No site leveling or raising is included in the estimate.
- The site has sufficient area available to accommodate construction activities including, but not limited to, construction offices (trailers), laydown, and staging.
- Wastewater treatment will include one clarification and sludge handling train. All transfer pumps, sludge pumps and chemical feed pumps will be designed with 2x100 percent redundancy. Wastewater treatment will include programmable logic controller (PLC) control panel, input/output (I/O) cabinets, and motor control center (MCC) all located in the metal building.

- Sludge hauling dumpster is not included in the estimate.
- No provisions for future expansion of the new wastewater treatment equipment are included.
- An emergency generator is not provided.
- Construction power will be provided by Vectren.
- The existing fire protection hydrant loop from the existing facility will be extended as required to serve the new metal building and water treatment areas. It is assumed that existing fire water pressure and volume are sufficient, therefore, no new fire pumps are included.
- Existing auxiliary power system can supply a minimum 100 amperes at 4160 volts.
- A new distributed control system (DCS) remote input/output (RIO) cabinet is located in the new electrical room in the metal building.
- There is fiber-optic connection to plant DCS.
- Add 30 percent for DCS programming engineering, arc flash coordination study.
- Uninterruptible power supply (UPS) feeds are based on typical primary/backup feed to DCS cabinets; other option is local mini-UPS located in Electrical Building. Power provided by available plant UPS.
- Heat trace loads that are nonfreeze protection lines (nonwater) are allowed off 120/208V panel in the power distribution center (PDC) in accordance with previous project work.
- Building will have 20 foot hi-bay ceilings, with potential second floor open grated level.
- All cables fed from plant; not from cooling tower area based on lack of information.
- New collection basin and wastewater treatment equipment sizing is based on two operating units.
- No changes to the current FGD wastewater mercury treatment equipment or any upstream piping or devices from either unit.
- Current coal pile runoff pump capacity is adequate to reach new collection basin based on topography, pump curve, and Black & Veatch flow modeling.
- New collection basin sizing is based on 20 minutes retention time for all flows identified on the Vectren water mass balance (WMB).
- Proposed treatment is based on flows in the A.B. Brown Plant Water Balance, Drawing F-2025.1, and water quality data provided by Vectren.
- Cooling tower blowdown flow rate and water quality assumes the cooling tower operates at six cycles of concentration. Copper content in the cooling tower blowdown is assumed to be reduced to 0.02 ppm after treatment in the existing cooling tower blowdown settling basins. This is consistent with existing plant water quality data.

- Proposed treatment assumes 60 gpm of SCC wastewater total for both units. SCC wastewater quality is assumed to be the same as the quality of the combined collection basin water, except with 1,000 ppm TSS.
- The coal pile runoff pond discharge will improve in quality as a result of the new FGD treatment system. The water quality for the coal pile runoff pond discharge is assumed to be a flow-proportioned blend of non-SCC wastewater (water quality of A.B. Brown's coal pile runoff sample) and the SCC wastewater.
- Proposed physical/chemical treatment assumes 99 percent removal of mercury, removal to 10 ppm TSS in clarifier effluent, and removal to 0.02 ppm copper in clarifier effluent.
- Proposed biological treatment assumes selenium removal to 0.01 ppm in system effluent.
- Proposed dewatering system assumes 99 percent of solids in feed will be removed in filter cake for disposal. Precipitated metals are included in this assumption.
- Treatment vessel will flow by gravity to the existing ash pond wastewater mercury treatment system.
- No electrical equipment or storage building provided at Location No. 3.
- Treatment system is not designed to handle chemical cleaning wastes.
- Required instrumentation is included in cost of treatment system.
- A.B. Brown Station bottom ash handling equipment costs are based on F.B. Culley Unit 3 design and recent proposals from United Conveyor Corporation for submerged chain conveyor.
- New high-pressure and low-pressure recirculation pumps will tie in to existing piping within plant.
- Existing excavated dirt is assumed to be suitable for backfill material. No imported fill is included.

B.2 DIRECT COST ASSUMPTIONS

The following assumptions are included in the base construction cost estimate for direct costs:

- All costs are expressed in 2019 dollars. No escalation is included.
- Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services.
- Construction costs are based on a turnkey construction approach. Construction is assumed to be performed based on a 50 hour workweek. Local union rates are used that include payroll, payroll taxes, and benefits. The consolidated labor rate used is about $75 per man-hour.

- Total capital costs are ±50 percent and include the costs associated with the purchase of equipment, erection, and all contractor services.
- Construction costs are based on an EPC construction approach.
- Capital direct cost for balance of plant treatment (BPT) assumed 4 percent equipment capital cost for equipment replacement during major outage.
- BPT treatment total capital costs include all common water treatment infrastructure.
- Selenium treatment total capital costs include only biological treatment that requires the BPT treatment system and entire infrastructure upstream for effluent compliance.
- BPT and selenium treatment is common equipment for both units.
- Leachate and WW Hg treatment is included in BPT treatment total capital costs.
- FBC selenium treatment includes all necessary equipment for effluent compliance; physical chemical treatment with biological.

B.3 INDIRECT COST ASSUMPTIONS

The following assumptions are included in the base construction cost estimate for indirect costs:

- General indirect costs include all necessary services required for checkouts, testing services, and commissioning.
- Insurance including builder's risk and general liability.
- Field construction management services including field management staff, supporting staff personnel, field contract administration, field inspection/quality assurance, and project controls.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond, and liability insurance for equipment and tools.
- Transportation costs for equipment and materials delivery to the jobsite.
- Startup/commissioning spare parts. Only miscellaneous parts used during the startup process are included. All major equipment long-term spare parts should be included in Vectren's costs.
- Construction contractor contingency costs.
- Construction contractor typical profit margin.
- Total capital costs do not include contingency, owner's cost, taxes, insurance, spare parts, or construction utility interconnections/consumables.

- O&M base non-labor cost for BPT assumed 2 percent equipment capital costs for maintenance items, consumables, and spare parts. Variable O&M costs are not included.

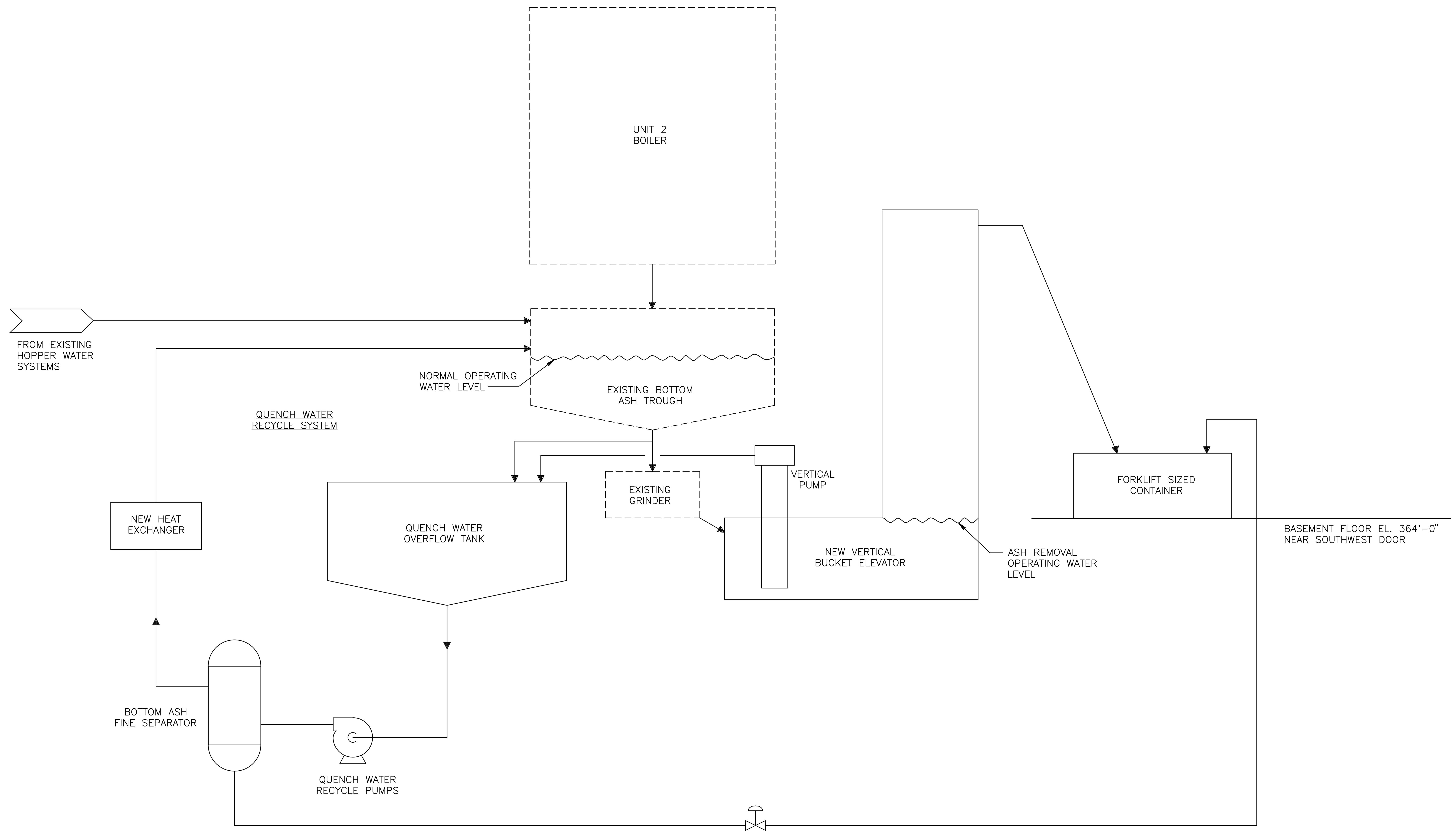
The following additional items of cost are not included in the construction estimate. These costs shall be determined by Vectren and are included in Vectren's cost estimate:

- Owner's contingency costs.
- Federal, state, and local taxes.
- Major equipment spare parts.
- Land.
- Interest during construction.
- Cost and fees for electrical, gas, and other utility interconnections.
- Project development costs, legal, and community outreach.
- All operating plant vehicles.
- No permitting costs have been included.
- Furniture, maintenance and office equipment, supplies, consumables, communications and plant IT systems, and startup fuel.
- Emissions credits.
- Environmental mitigation.

Appendix C. List of Process Flow Diagrams

C.1 PROCESS FLOW DIAGRAMS FOR F.B. CULLEY UNIT 2

C.2 PROCESS FLOW DIAGRAMS FOR A.B. BROWN UNITS 1 AND 2



NOT TO BE USED
FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	28/JUL/16	ISSUED FOR CLIENT REVIEW	DRE	EGC		LRK	

BLACK & VEATCH
Building a world of difference®

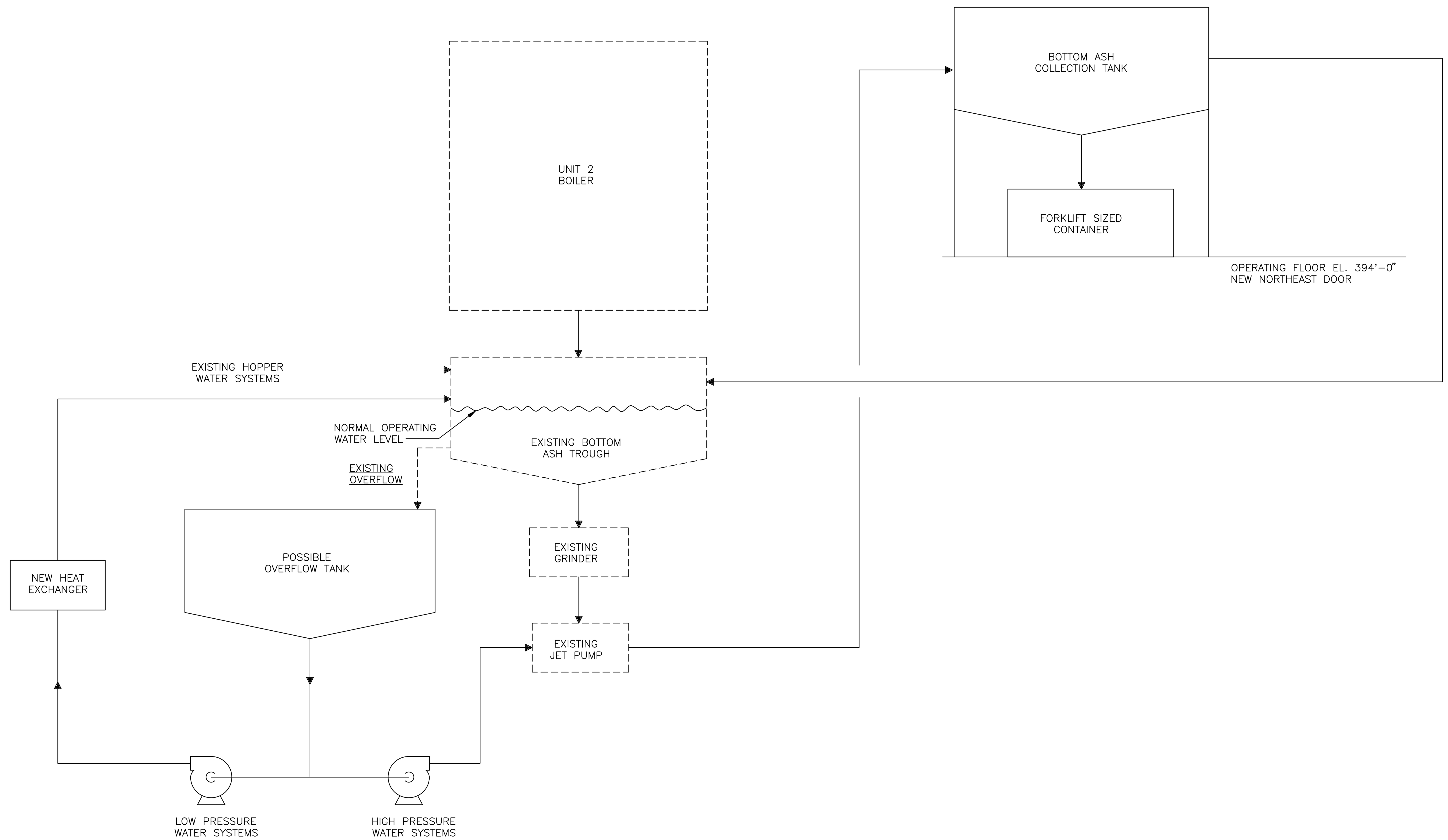
DESIGNER LRK DRAWN DRE
CHECKED DATE

VECTREN POWER SUPPLY
CULLEY STATION UNIT 2

ALTERNATIVE 1
VERTICAL BUCKET ELEVATOR FLOW DIAGRAM

PROJECT DRAWING NUMBER
190507-PFD-4000
REV A
CODE
AREA

ELY65172 D1 1=1
A1ASL028 15:24:16
08/02/16 ACAD 18.2s (LMS Tech)



NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

ACAD 18.2s (LMS Tech)
D1 1=1
ELY65172 A1ASL028 08/03/16 08:40:25

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	28/JUL/16	ISSUED FOR CLIENT REVIEW	DRE	EGC		LRK	

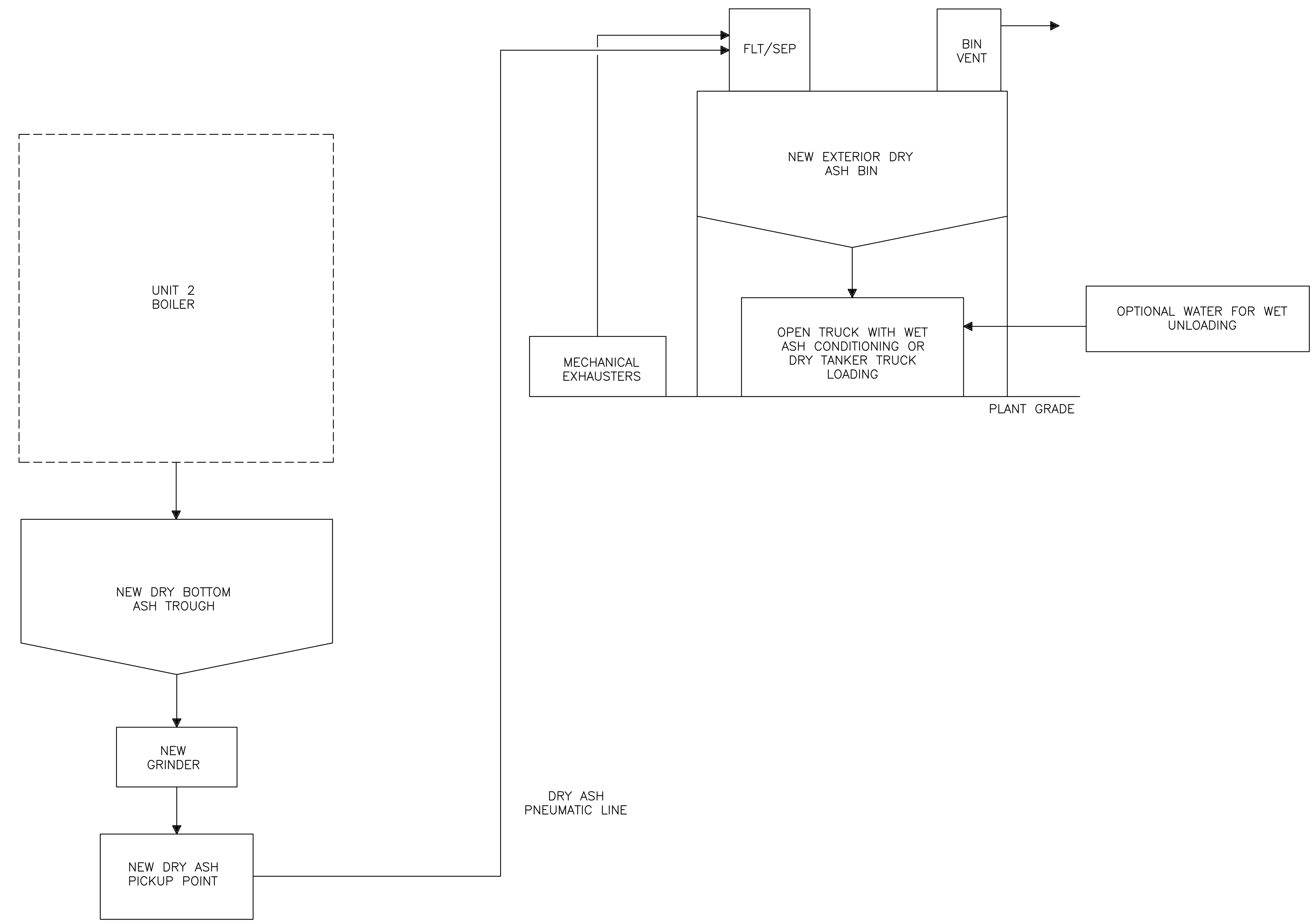
BLACK & VEATCH
Building a world of difference®

DESIGNER LRK | DRAWN DRE
CHECKED | DATE

VECTREN POWER SUPPLY
CULLEY STATION UNIT 2

ALTERNATIVE 2
INTERIOR DEWATERING TANK FLOW DIAGRAM

PROJECT DRAWING NUMBER 190507-PFD-4001
REV A
CODE
AREA



NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	28/JUL/16	ISSUED FOR CLIENT REVIEW	DRE	EGC		LRK	

BLACK & VEATCH
Building a world of difference®

DESIGNER LRK | DRAWN DRE | CHECKED | DATE

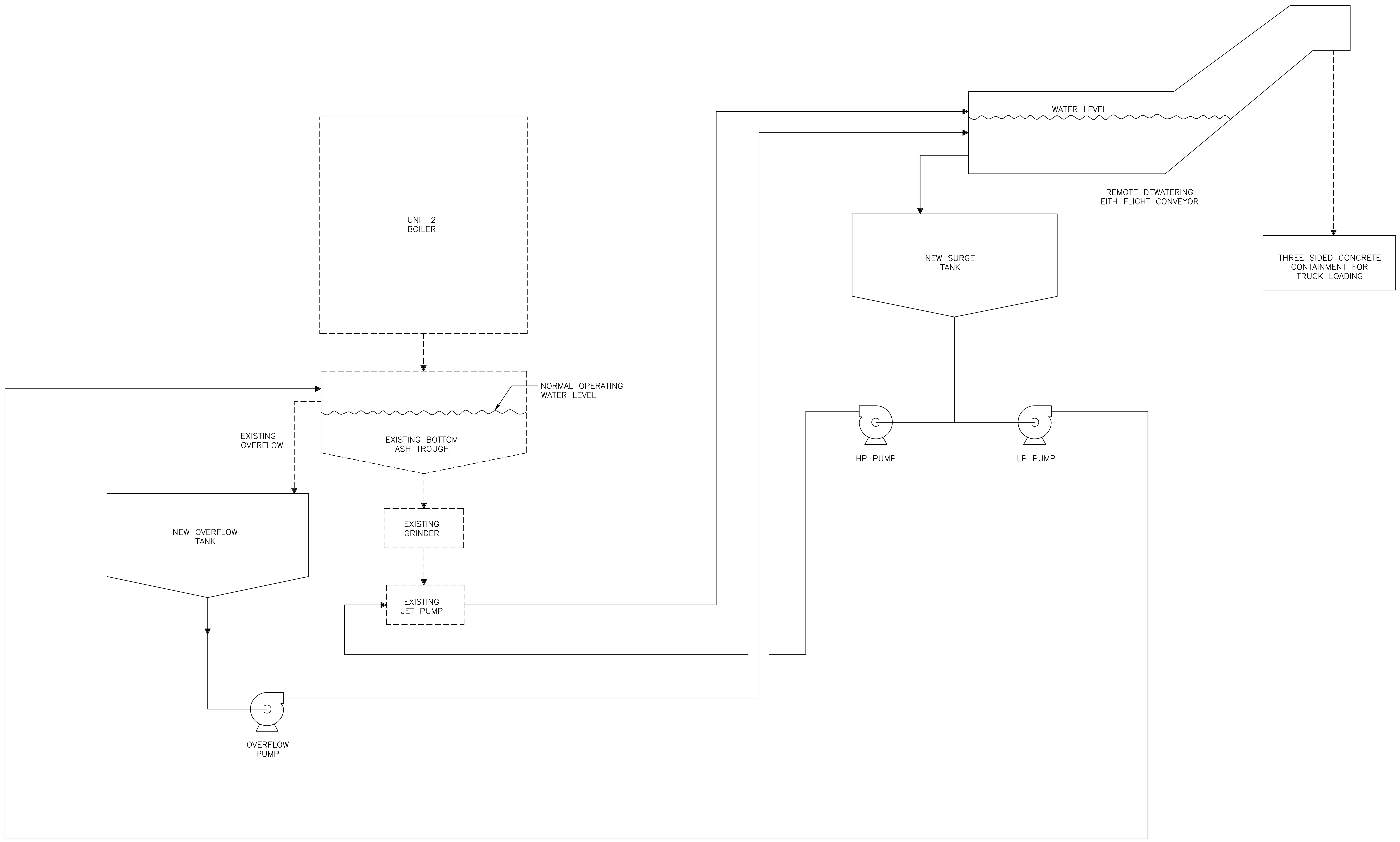
VECTREN POWER SUPPLY
CULLEY STATION UNIT 2

ALTERNATIVE 3
PNEUMATIC ASH REMOVAL FLOW DIAGRAM

PROJECT | DRAWING NUMBER: 190507-PFD-4002 | REV: A

CODE | AREA

ELY65172 A1ASL028 08/03/16 08:21:04 D1 1=1 ACAD 18.2s (LMS Tech)



NOT TO BE USED
FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	28/JUL/16	ISSUED FOR CLIENT REVIEW	DRE	EGC		LRK	

BLACK & VEATCH
Building a world of difference®

DESIGNER LRK | DRAWN DRE | CHECKED | DATE

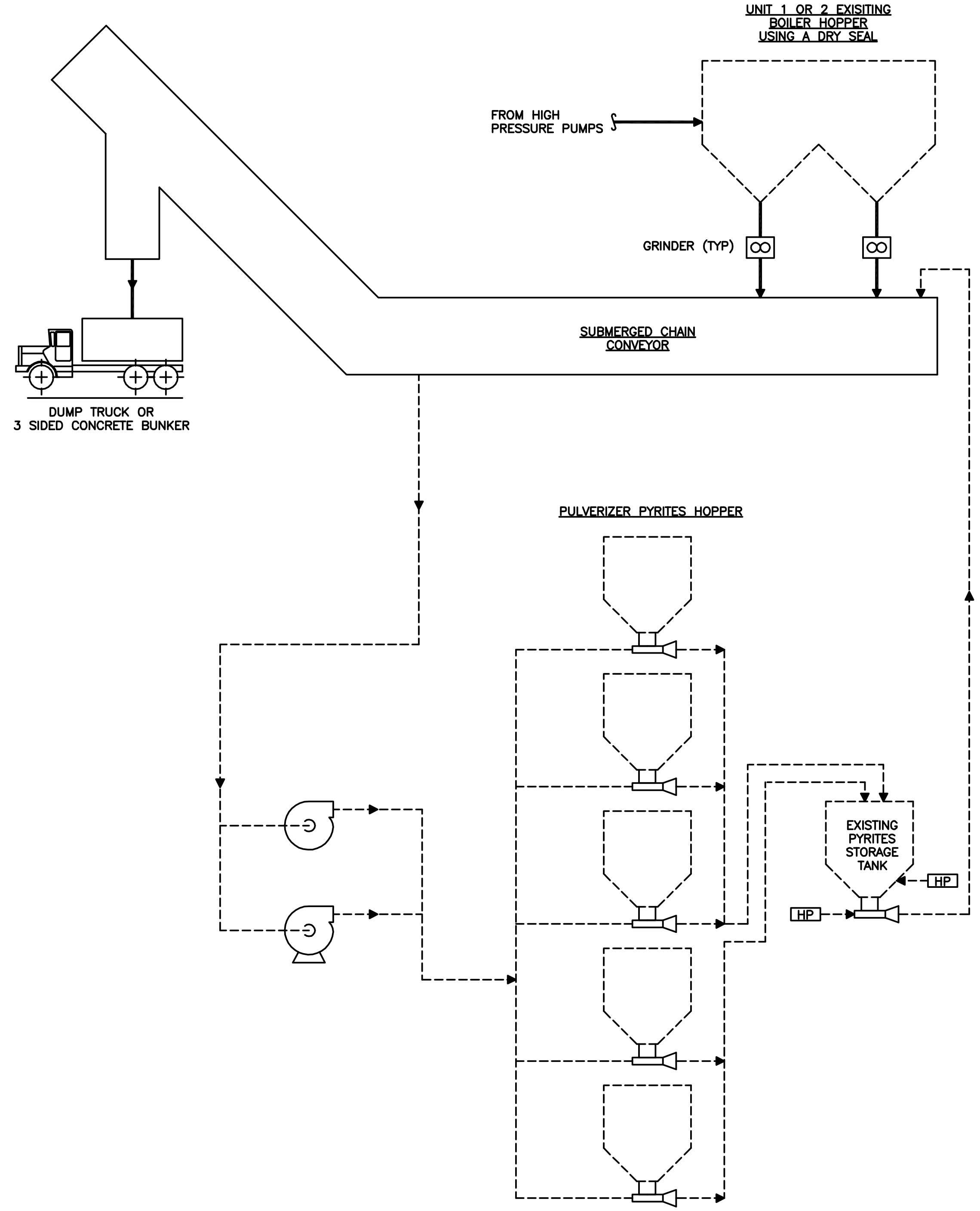
VECTREN POWER SUPPLY
CULLEY STATION UNIT 2

ALTERNATIVE 4
REMOTE DEWATERING FLIGHT CONVEYOR FLOW

PROJECT | DRAWING NUMBER: 190507-PFD-4003 | REV: A

CODE | AREA

ELY65172 A1ASL028 08/03/16 08:57:09
D1 1=1
ACAD 18.2s (LMS Tech)



NOT TO BE USED
FOR CONSTRUCTION
THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	03/JUL/19	ISSUED FOR CLIENT REVIEW	JLH	MWE		KMK	

BLACK & VEATCH
Building a world of difference.

DESIGNER MWE
DRAWN JLH
CHECKED
DATE

VECTREN POWER SUPPLY
A.B. BROWN STATION (UNIT 1 OR 2)

ALTERNATIVE 1
SUBMERGED CHAIN CONVEYOR

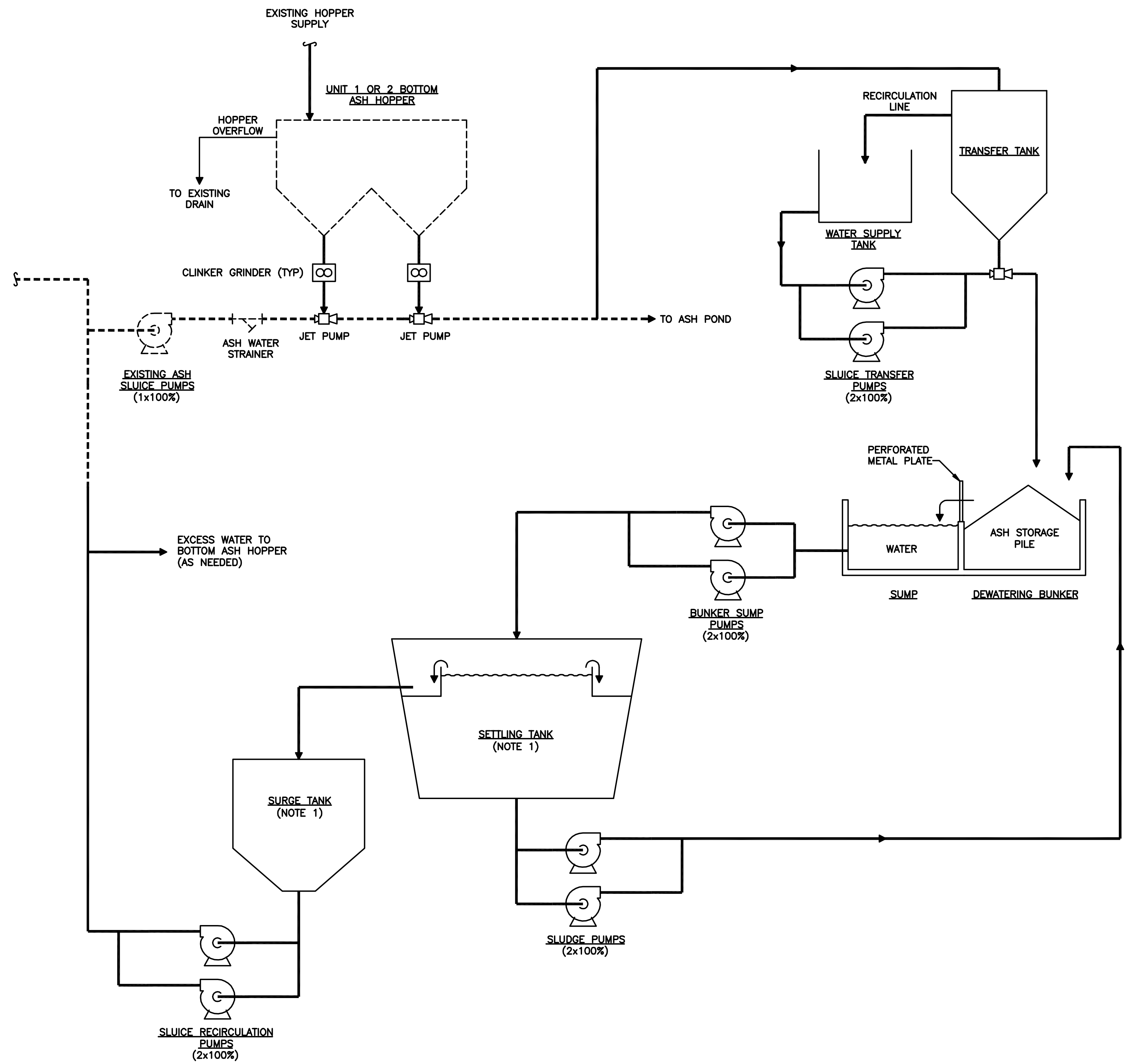
PROJECT 190507
DRAWING NUMBER PFD-4004
REV A
CODE
AREA

ELY65172 A1ASL028 11/14/16 09:48:42 D1 1=1 ACAD 18.2s (LMS Tech)

Cause No. 45564

NOTES:

1. SETTLING TANK & SURGE TANK NEED FURTHER INVESTIGATION.



NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	03/JUL/19	ISSUED FOR CLIENT REVIEW	JLH	MWE		KMK	

BLACK & VEATCH
Building a world of difference.

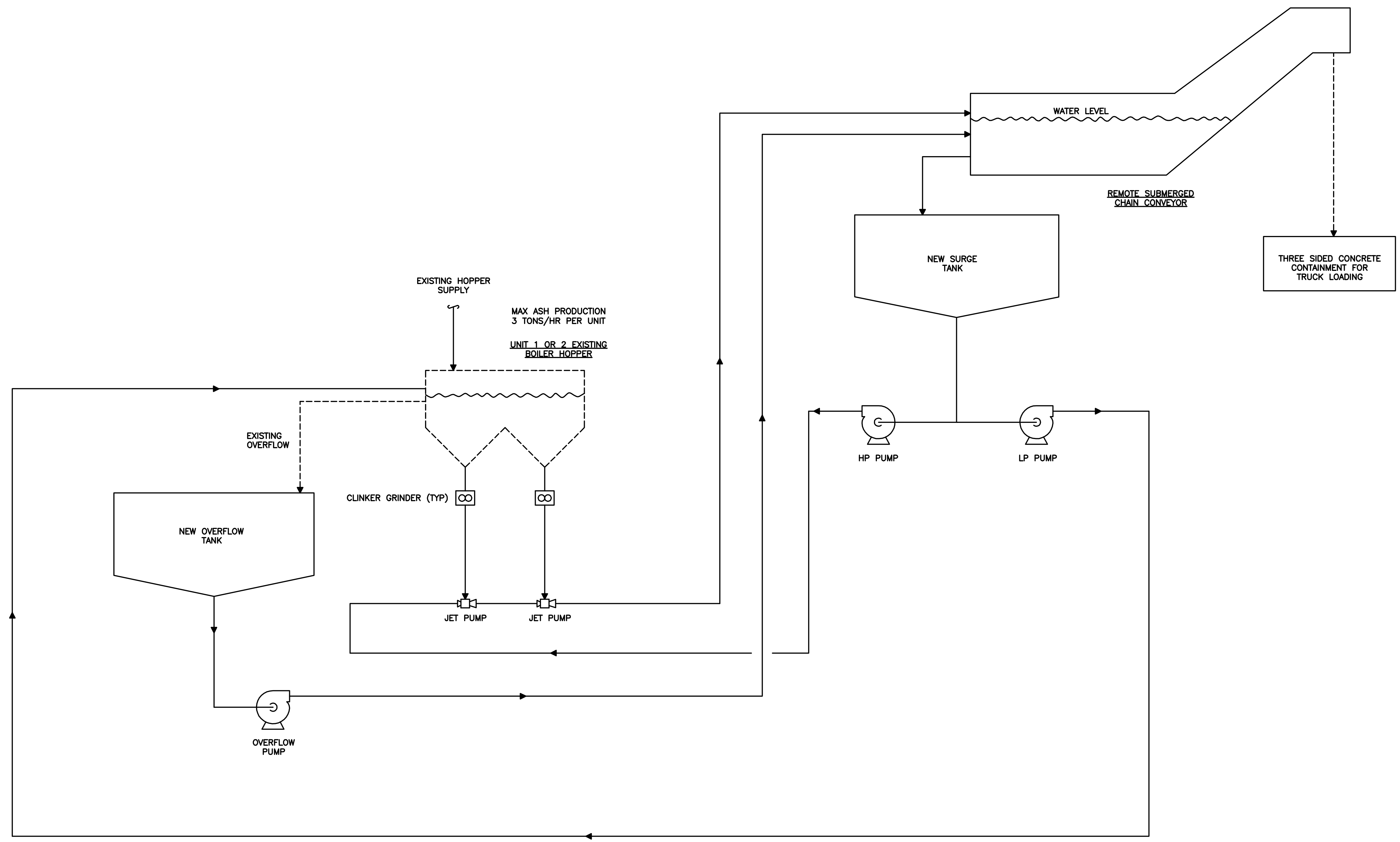
DESIGNER MWE
DRAWN JLH
CHECKED
DATE

VECTREN POWER SUPPLY
A.B. BROWN STATION (UNIT 1 OR 2)

ALTERNATIVE 2
BOTTOM ASH DEWATERING BUNKER

PROJECT 190507
DRAWING NUMBER PFD-4005
REV A
CODE
AREA

ELY65172 D1 ACAD 18.2s (LMS Tech)
A1ASL028 1=1
08/04/16 10:48:15



NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	03/JUL/19	ISSUED FOR CLIENT REVIEW	JLH	MWE		KMK	

BLACK & VEATCH
Building a world of difference.

DESIGNER MWE | DRAWN JLH
CHECKED | DATE

VECTREN POWER SUPPLY
A.B. BROWN STATION (UNIT 1 OR UNIT 2)

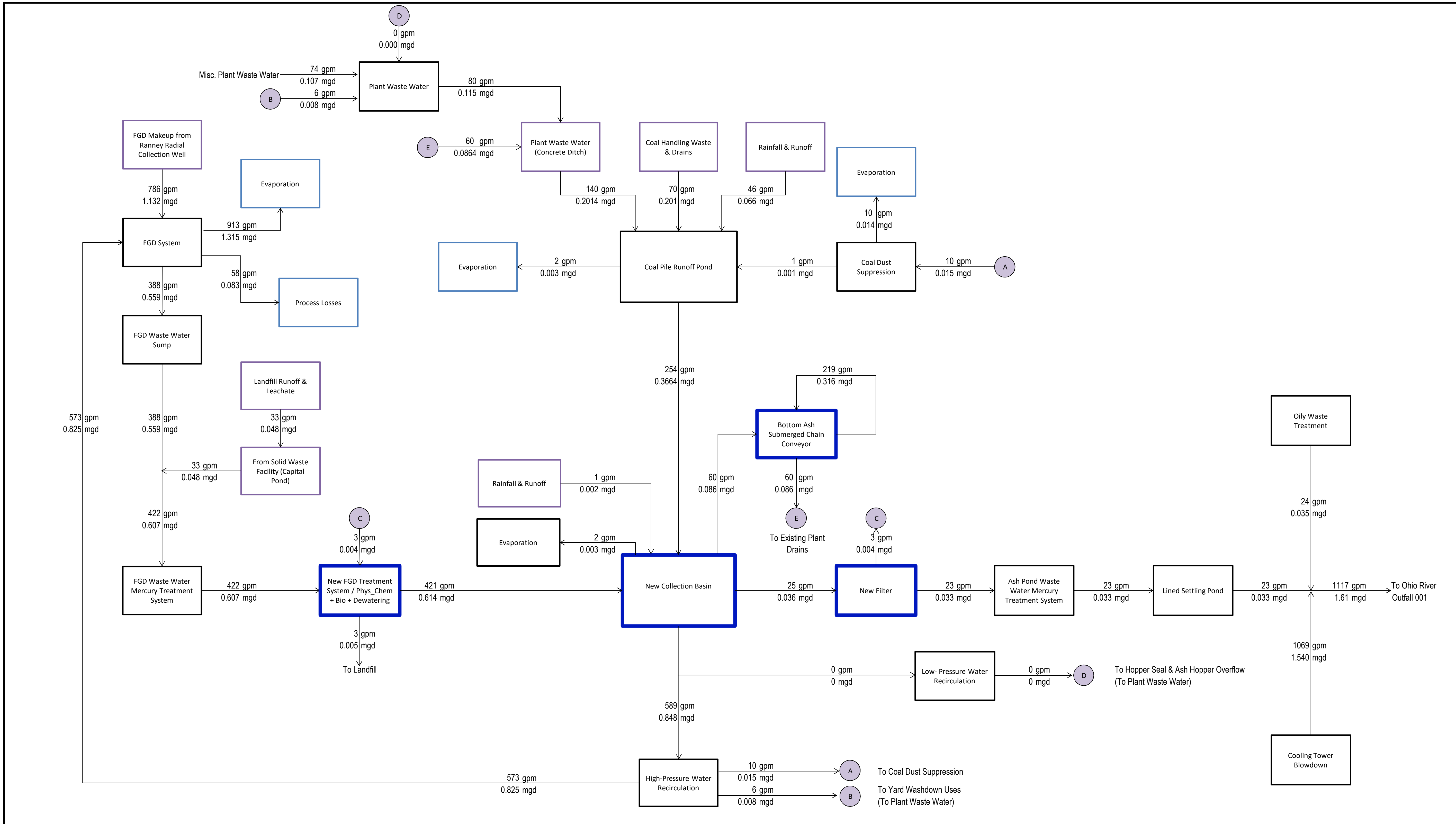
ALTERNATIVE 3
REMOTE SUBMERGED CHAIN CONVEYOR FLOW

PROJECT | DRAWING NUMBER 190507-PFD-4006 | REV A
CODE
AREA

ELY65172 A1ASL028 08/22/16 D1 1=1 16:16:10 ACAD 18.2s (LMS Tech)

Appendix D. Water Mass Balance Diagram

D.1 WATER MASS BALANCE DIAGRAM FOR A.B. BROWN



A	2/21/20	ELG - CCR Compliance Report	VMM	AJF	Eng:	Dwg:
NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	ENG		Date: 2/21/2020

BLACK & VEATCH
Building a world of difference.

Vectren Corp.
A.B. Brown Station
WATER MASS BALANCE - Dual Alkali Scrubber

REV
A

Attachment 6.8 ACE Rule Heat Rate Study

FINAL

EPA ACE HEAT RATE STUDY

B&V PROJECT NO. 402338
B&V FILE NO. 40.0004

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

16 JANUARY 2020

BLACK & VEATCH

Table of Contents

LIST OF TABLES

LIST OF FIGURES

Executive Summary

The Affordable Clean Energy (ACE) rule, finalized by the United States Environmental Protection Agency (EPA) on June 19, 2019, establishes new standards for reducing greenhouse gas (GHG) emissions for coal-fired electric utility generating units (EGUs) based on the "best system of emission reduction" (BSER). First proposed in August 2018, the rule, Docket ID No. EPA-HQ-OAR-2017-0355: FRL-9995-70-OAR, "Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations," focuses on measures that can be implemented within the fence line of existing EGU facilities. As such, the EPA concluded that BSER be limited to heat rate improvements (efficiency improvements) for existing coal-fired EGUs. Within ACE, the EPA identified a list of candidate technologies and measures to achieve heat rate improvements (HRI).

In anticipation of the final rule, Vectren requested that Black & Veatch assess these candidate technologies for improvements at four coal fired plants (A.B. Brown Unit 1, A.B. Brown Unit 2, Culley Unit 2, and Culley Unit 3) to meet the goals of the ACE rule. Black & Veatch reviewed the characteristic of the four plants and examined each plant according to several BSER alternatives:

- Steam turbine blade path upgrades.
- Redesign or replacement of the economizer.
- Air heater and duct leakage control.
- Variable frequency drive (VFD) deployment.
- Neural networks.
- Intelligent sootblowing (ISB).
- Various improved operations and maintenance (O&M) practices.

Several factors influenced the recommendations for upgrades at the four plants; these factors are discussed in detail in Section 3.0. A summary of Black & Veatch's assessment and recommendations is as follows:

- The existing steam turbines at A.B. Brown Units 1 and 2 have been upgraded to full dense pack and no significant improvement in heat rate would result in additional upgrades; a turbine blade path upgrade would improve heat rate at F.B. Culley Unit 3 (1.4 to 1.6 percent). Steam turbine blade path upgrades options for F.B. Culley Unit 2 would improve heat rate by 1.3 to 1.5 percent, at a cost of $10.4 million.
- Economizer upgrades are not recommended for A.B. Brown Units 1 and 2 or F.B. Culley Unit 3 at this time; upgrades at F.B. Culley Unit 2 would require significant investment and require further study. A boiler modeling study of the potential benefits of reducing economizer surface area at A.B. Brown Units 1 and 2 or F.B. Culley Unit 3 found that although there was a potential reduction in natural gas use for the gas burners, the net impact upon the units was negative.
- Recommendations were provided for improving unit air heaters at all four units.

- Estimated costs are provided for VFD improvements for the FD and ID Fans at A.B. Brown Units 1 and 2. VFD improvements were studied for the FD fans at F.B. Culley Units 2 and 3 as both units ID fans have already been upgraded with VFDs.
- The deployment of VFDs for circulating water pumps was studied at all four units, but in no instance was it found to be a cost-effective HRI option.
- Estimated costs are provided for neural network deployment at all four units.
- F.B. Culley Unit 2 is the only unit that could benefit from ISB; the other units already use this technology.
- Improved O&M practices include heat rate improvement training, on-site heat rate appraisals, and improved condenser cleanliness strategies; these techniques may result in improvements at all four units.

Overall, many opportunities exist for heat rate improvement at the A.B. Brown and F.B. Culley units in compliance with the EPA-ACE rule. The decision of which heat rate improvements should be pursued must be based upon the long-term plans for the continued operation of the units, and the specific cost/benefit factors for each improvement found in Appendix B.

Recommendations

The following recommendations have been made for the units, based upon their past performance and current operations, as well as the expected future payback potential.

- For the A.B. Brown 1, A.B. Brown 2, and F.B. Culley 3 units upgrades to the air heaters and repair and remediation of ductwork and air quality control systems leakage appears to have a high value to the plants. In the case of air heater upgrades the improvement in heat transfer will improve the boiler efficiency, and the reduction in air heater leakage will reduce station service by reducing the air and gas main fan flow requirements. Reductions in duct leakage and leakage in air quality control equipment leakage will significantly improve induced draft fan performance and will reduce station service. There will also be the ancillary benefit of improved operations and efficiency of the air quality control equipment for emissions reduction.

  F.B. Culley Unit 2 was found to have a poor cost/benefit ratio for these upgrades due to its very low capacity factor and net generation, as well as its relatively short remaining useful life. F.B. Culley Unit 3 on the other hand was found to have the best potential benefit from air heater and duct leakage improvements from the standpoint of improvement per capital dollar spent.

- Steam turbine and blade path upgrades were analyzed for F.B. Culley Units 2 and 3 (A.B. Brown Units 1 and 2 were judged not to benefit from them sufficiently to warrant further upgrades, due to their relatively recent dense pack refurbishments) but only upgrades respective to F.B. Culley Unit 3 were found to be technically feasible and cost-effective at this time. However, as the New Source Review (NSR) exemption portion of EPA-ACE has been deferred and will be proposed in a separate action at a later date, pursuing steam turbine upgrades at this time should be done under the consideration of the potential for triggering NSR.

- Variable frequency drive deployment was found to be only advantageous for the induced draft fans on A.B. Brown Units 1 and 2. For all other systems and the F.B. Culley units, either VFDs had already been deployed to critical systems, or there was no acceptable cost/benefit to further deployment.
- Deploying a neural network or other boiler optimization system was found to be beneficial for all units except F.B. Culley Unit 2, which again was excluded due to its low capacity factor and output. Even modest improvements in optimization could result in significant improvements to heat rate and overall unit control and emissions.
- Heat rate awareness training was found to be a very good cost/benefit for all the units and could yield significant improvements in operations practices and responses to controllable losses at both plants. Targeted heat rate assessment, while difficult to quantify exactly, is expected based upon Black & Veatch experience to have a very high return on investment, and numerous examples have been provided in the text from past projects.
- The addition of more circulating water temperature measurements leaving the condenser would also improve accuracy of results by better capturing temperature stratification in the return piping.

Summary of Costs

The following table provides a summary of costs associated with the recommended ACE technologies for each unit. Additional detailed cost estimates for each unit can be found in Appendix B.

Table ES-1 A.B. Brown Unit 1 Summary of ACE Technology Costs

Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)
Air Heater Basket, Seal, and Sector Plate Replacement	850	0.50	57.88
Air Heater (Steam Coil) System Repairs	350	0.10	11.6

Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)
Circulating Water Pumps	2,100	N/A	N/A
Induced Draft Fans VFD Deployment	2,900	2.39	276.5
Forced Draft Fans VFD Deployment	2,000	0.43	50.3
Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess O_2)	500	0.23 to 0.60	26.6 to 69.5
Heat Rate Improvement Training	15	0.30	34.7
On-Site Heat Rate Appraisals	Variable	Variable	N/A
Improved Condenser Cleaning Strategies	N/A	0.15	17.4

Table ES-2 A.B. Brown Unit 2 Summary of ACE Technology Costs

Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)
Air Heater Basket, Seal, and Sector Plate Replacement	850	0.50	55.0
Air Heater (Steam Coil) System Repairs	350	0.10	11.0
Circulating Water Pumps	2,100	N/A	N/A
Induced Draft Fans VFD Deployment	2,900	1.33	146.3
Forced Draft Fans VFD Deployment	2,000	0.26	28.6
Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess O_2)	500	0.30 to 0.60	25.3 to 66.0
Heat Rate Improvement Training	15	0.30	33.0
On-Site Heat Rate Appraisals	Variable	Variable	N/A
Improved Condenser Cleaning Strategies	N/A	Negligible	Negligible

Table ES-3 F.B. Culley Unit 2 Summary of ACE Technology Costs

Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)
Air Heater Basket, Seal, and Sector Plate Replacement	476	0.50	63.2
Circulating Water Pumps	900	N/A	N/A
Forced Draft Fans VFD Deployment	2,000	0.48	60.9
Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess O_2)	500	0.26 to 0.62	32.9 to 78.4
Boiler Feed Pump VFD Deployment	600	0.6	75.8
Synchronized Controlled Sootblowing System Designed to Alleviate Excessive Use of Steam, Air or Water That Have A Negative Effect on Heat Rate.	350	0.10	12.64
Heat Rate Improvement Training	15	0.30	37.9
On-Site Heat Rate Appraisals	Variable	Variable	N/A
Improved Condenser Cleaning Strategies	N/A	0.42	53.1

Table ES-4 F.B. Culley Unit 3 Summary of ACE Technology Costs

Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)
HP/IP Upgrades	19,900	1.5	158.3
Air Heater Basket, Seal, and Sector Plate Replacement	750	0.50	52.8
Air Heater (Steam Coil) System Repairs	350	0.10	10.6
Circulating Water Pumps	2,100	N/A	N/A
Forced Draft Fans VFD Deployment	2,000	0.51	54.3
Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess O_2)	500	0.25 to 0.62	26.4 to 65.4
Heat Rate Improvement Training	15	0.30	31.7
On-Site Heat Rate Appraisals	Variable	Variable	N/A
Improved Condenser Cleaning Strategies	N/A	0.44	46.4

1.0 Introduction

Vectren requested that Black & Veatch support its efforts to analyze a potential response to the United States Environmental Protection Agency (EPA) Docket ID No. EPA-HQ-OAR-2017-0355: FRL-9995-70-OAR, "Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations;" known as the Affordable Clean Energy (ACE) rule. Vectren operates the A.B. Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3 coal-fired electric generating units (EGUs) and specifically requested that Black & Veatch develop a high-level assessment report identifying opportunities to improve plant efficiency to meet ACE rule goals.

To meet these goals, Black & Veatch prepared a high-level description of four primary heat rate improvement (HRI) projects that have been proposed by the EPA as the best system of emission reduction (BSER). Estimates of HRI, annual carbon dioxide (CO_2) reduction, and a rough order-of-magnitude capital cost estimate were developed for each alternative.

Black & Veatch performed a high-level assessment to consider the technical and economic feasibility of items that have been seen as beneficial in previous ACE studies. Financial benefits would be confirmed by integrated resource plan (IRP) modeling; specific modifications would then be reviewed in a detailed effort to confirm the performance and financial benefits.

1.1 AN OVERVIEW OF EPA-ACE

On June 19, 2019, EPA issued the ACE rule, a replacement to the previous presidential administration's Clean Power Plan (CPP) to regulate CO_2 emissions from existing coal-fired power plants. ACE regulates EGUs based on the BSER. Unlike the CPP, ACE focuses on only those measures which can be implemented within the fence line of existing EGU facilities. As such, EPA has determined BSER to be limited to heat rate improvement (HRI) measures (efficiency improvements) for existing coal-fired EGUs at the individual unit level. The lower a unit's heat rate, the more efficiently it will convert heat input to electrical output, consuming less fuel per kilowatt-hour (kWh) and emitting lower amounts of CO_2. To aid operators and state agencies in determining which measures should be considered when determining BSER, EPA developed a list of 7 HRI candidate technologies. According to EPA, these technologies have been shown to be reliable, efficient, cost-effective, and broadly achievable for a source category across the country. The technologies include:

- Steam turbine blade path upgrades.
- Redesign or replacement of the economizer.
- Air heater and duct leakage control.
- Variable frequency drive (VFD) deployment.
- Neural networks/Intelligent sootblowing (ISB).
- Boiler feed pump upgrade/overhaul
- Various improved operations and maintenance (O&M) practices.

The EPA has responsibility under the CAA to provide a range of reductions and costs associated with each of the candidate technologies. The ranges of expected reductions for each technology are to be used as guidance, but the states will be expected to evaluate each affected unit individually. For reference, EPA's summary of HRI measures and the range of their HRI potential (%) by EGU size is included in Table 1-1. These ranges represent the degree of emission reduction achievable for each technology, however the EPA acknowledges that a specific unit may have the potential for more or less emission reduction based on the unit's specific characteristics. According to the preamble to the final rule, HRI potential will be determined by source-specific factors including, but not limited to, the EGU's past and projected utilization rate, maintenance history, and remaining useful life[1].

Table 1-1 EPA's Summary of HRI Measures and Range of HRI Potential (%) by EGU Size

HRI MEASURE	<200 MW		200-500 MW		>500 MW	
	MIN	MAX	MIN	MAX	MIN	MAX
Neural Network/Intelligent Sootblowers	0.5	1.4	0.3	1.0	0.3	0.9
Boiler Feed Pumps	0.2	0.5	0.2	0.5	0.2	0.5
Air Heater & Duct Leakage Control	0.1	0.4	0.1	0.4	0.1	0.4
Variable Frequency Drives	0.2	0.9	0.2	1.0	0.2	1.0
Blade Path Upgrade (Steam Turbine)	0.9	2.7	1.0	2.9	1.0	2.9
Redesign/Replace Economizer	0.5	0.9	0.5	1.0	0.5	1.0
Improved Operating and Maintenance (O&M) Practices	Can range from 0 to >2.0% depending on the unit's historical O&M practices.					

Ultimately, it is the EPA's role to determine the possible BSERs and the degree of emission control achievable for each technology, and it is the states' role to create plans establishing unit-specific standards (in a lbm CO_2/MWh format) that reflect the application of the BSER. Each state will be required to submit plans (or a State Implementation Plan [SIP]) to the EPA explaining how the state applied the BSER to each source and what other factors were considered when developing the unit-specific standards. In addition to the performance standards, states will also propose compliance deadlines for each EGU, as well as monitoring, recordkeeping and reporting requirements in their plans. These plans will be due to the EPA in three years (July 2022). Upon submittal, the EPA will have 12 months to determine whether or not to approve the plan.

[1] This could have the most significant implications for F.B. Culley Unit 2.

The emission limits and requirements for Vectren's affected EGUs will ultimately be established by IDEM. States are afforded considerable flexibility in determining emission standards for each unit as each state is more familiar with the existing sources within their jurisdictions. States are to use the guidelines EPA provided to evaluate each applicable EGU within its jurisdiction with regards to the utilization of each of the candidate technologies, equipment upgrades, and best O&M practices in establishing a standard of performance for that source. Physical and cost considerations will limit or prevent full implementation of the listed technologies and each state will consider these factors when establishing the standards of performance required. The remaining useful life of the source and other source-specific factors will also be considered by the states when establishing the standards of performance for each unit.

It will be the states' responsibilities to determine how these factors will be taken into consideration when establishing the standards. One approach that states may use is a top-down analysis that examines technical feasibility and cost effectiveness when determining an appropriate standard. Black & Veatch notes that variations of this type of analysis have been used by EPA in multiple regulatory programs to determine appropriate controls (e.g., BACT, RACT, BART, etc.). Such an analysis of the candidate BSER technologies could entail the following steps:

1. Identify all technologies (This step has already been done by the rule);
2. Eliminate technically infeasible options;
3. Rank remaining technologies by effectiveness;
4. Evaluate the most effective controls – entails energy, environmental, and economic impacts – cost effectiveness could entail a consideration of remaining useful life to ultimately determine the cost of a technology on the basis of dollars per lbm CO_2/MWh improvement.
5. Select the appropriate technology and set a standard of performance in terms of a lbm CO_2/MWh emission rate.

Black & Veatch notes that such an approach could provide state agencies such as IDEM with the defensible approach that they seek to avoid potential legal vulnerabilities while at the same time allowing Vectren to implement the most cost-effective option. Given the lack of specificity in the Rule, IDEM and their stakeholders have been afforded a great deal of latitude in designing the SIP. Therefore, early engagement with IDEM is encouraged in order to influence and assist in their determinations of the appropriate performance standard to include in the SIP for Vectren's affected units.

Numerous lawsuits have already been filed against the ACE rule, however, no stay (delay in rule administration) has been requested to this point. As with many environmental rules, industry sentiment is that the Rule's fate could be determined by the 2020 presidential election. In the meantime, however, Black & Veatch would expect that states will begin to gather information in order to begin designing their SIPs.

1.2 EPA'S INTEGRATED PLANNING MODEL

To assess the potential costs and benefits associated with the ACE rule, the EPA used the Integrated Planning Model (IPM) in support of final rulemaking. According to EPA documentation on the latest version of the model (EPA Platform v6, November 2018), "IPM is a multi-regional […] model of the U.S. electric power sector" that provides "[…] forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand, environmental, transmission, dispatch, and reliability constraints." Historically, EPA has used the IPM to forecast power sector behavior and examine the impact of potential air pollution control policies. The EPA has used this model for over two decades to evaluate the economic and emission impacts of potential environmental regulations. Specifically, EPA has used v6 to develop regulatory impact analyses in support of the Cross-State Air Pollution Rule (CSAPR), the greenhouse gas New Source Performance Standard (NSPS) for new, modified, and reconstructed electric utility generating units (NSPS Subpart TTTT), the Mercury and Air Toxics Rule (MATS), the Regional Haze Rule, 316b, and ELG/CCR regulations.

The EPA IPM is quite complex and utilizes numerous inputs to characterize the power sector including:

- Power System Operation
- Generation Resources
- Emission Control Technologies
- CO_2 Capture, Transport, and Storage
- Coal Characteristics (i.e., Supply Curves and Transportation Matrix)
- Natural Gas Market Characteristics
- Other Fuel Assumptions
- Financial Assumptions

These inputs are processed in the model in order to arrive at outputs quantifying sector-wide emissions, costs, capacity expansion, retrofit decisions, fuel consumption and prices, and electricity generation and prices. Finally, these outputs can be fed into a post-processor in order to forecast individual boiler-level data, retail electricity price projections, and outputs needed to assess the impacts on air quality via air quality modeling. According to the model documentation, "The model has been tailored to meet the unique environmental considerations important to EPA, while also fully capturing the detailed and complex economic and electric dispatch dynamics of power plants across the country."

The IPM model was not designed to evaluate the technological or economic feasibility of the various BSER technologies for a single ACE-affected unit, but, rather, is intended to be used to holistically evaluate the impacts of EPA rulemakings on the entire power sector. Additionally, the model appears overly complex, such that it could be time-consuming and provide a false sense of accuracy when used to evaluate the technologies as part of an ACE study. As such, it is unlikely that the IPM would/should ever be utilized to evaluate the BSER technologies as a part of a state ACE compliance plan.

1.3 POTENTIAL NEW SOURCE REVIEW CHANGES

To accommodate and facilitate the HRI projects associated with the ACE rulemaking, EPA has proposed changes to the New Source Review (NSR) permitting program. Under the current regulations, modifications to stationary sources, such as EGUs, that increase annual emissions of regulated pollutants at or above certain regulatory thresholds are subject to NSR permitting requirements. EPA is now proposing to incorporate a comparison of hourly emissions into the NSR applicability assessment for EGUs. Under this approach, the maximum actual emissions values measured on an hourly basis before the project and the projected hourly emission rate that will occur after the proposed modification would be compared to determine if an emission increase would result. If no *hourly* emissions increase will occur, NSR would not be applicable.

However, if hourly emissions were determined to increase, the emissions analysis must continue per the traditional methodology where an assessment of both project-specific overall emissions increases, and plant-wide net emissions increases on an annual basis would need to be calculated to determine if NSR permitting requirements would apply. Black & Veatch notes that this proposed rule-making is considered particularly vulnerable to legal challenges. Therefore, an evaluation of the potential applicability of NSR to each of the BSER options examined in this report may be prudent in order to provide Vectren a full picture of the costs project timeline associated with the various options. Additionally, EPA has noted in the final rule, that costs associated with permitting NSR applicable projects can be included in the economic evaluation of the various ACE technologies.

2.0 Existing Plant Characteristics

This section briefly describes the baseline characteristics of each unit. The average and summary annual performance data for each unit that were used to calculate the potential heat rate benefits of applicable technologies can be found in Section 4.0.

A.B. Brown Units 1 and 2 are “sister units” in that they share many common characteristics. Each unit is a nominal 265-megawatt (MW) gross and 245 MW net unit, featuring a subcritical pulverized coal furnace with reheat steam and designed for bituminous coal from the Illinois Basin. A.B. Brown Unit 1 was commissioned in 1979, and A.B. Brown Unit 2 in 1986. Each unit employs low-nitrogen oxide (NO_X) burners and a selective catalytic reduction system (SCR) for NO_X control, and a scrubber for sulfur dioxide (SO_2) control. Unit 1 uses a pulse-jet fabric filter baghouse, and Unit 2 uses a cold-side electrostatic precipitator for particulate removal. Heat rejection is provided by mechanical draft cooling towers.

F.B. Culley Unit 2 is a nominal 100 MW gross and 90 MW net unit, featuring a non-reheat subcritical pulverized coal furnace designed for bituminous coal from the Illinois Basin. F.B. Culley Unit 2 was commissioned in 1966. The unit employs low-NO_X burners for NO_X control and a scrubber for SO_2 control. The unit uses a cold-side electrostatic precipitator for particulate removal. Cooling water is provided by the Ohio River.

F.B. Culley Unit 3 is a nominal 287 MW gross and 270 MW net unit, featuring a subcritical pulverized coal furnace with reheat steam and designed for bituminous coal from the Illinois Basin. F.B. Culley Unit 3 was commissioned in 1973. The unit employs low-NO_X burners and an SCR system for NO_X control and a scrubber for SO_2 control. The unit uses a pulse-jet fabric filter (PJFF) baghouse for particulate removal. Cooling water is provided by the Ohio River.

3.1 Description of Heat Rate Improvement Alternatives

This preliminary heat rate project screening was based on a high-level analysis of A.B. Brown Unit 1 and on Black & Veatch's experience with similar projects. The projects depicted herein were selected from HRI projects detailed by the EPA in its ACE rule as BSER projects. A detailed table summarizing the benefits and costs is included in Appendix B.

3.2 UNIT STEAM TURBINE BLADE PATH UPGRADES

Black & Veatch reviewed the steam turbine blade path upgrade option for each of the existing plants. The specific steam turbine upgrades are described for each individual plant in the following subsections.

3.2.1 A.B. Brown Unit 1 Steam Turbine Blade Path Upgrades

Black & Veatch reviewed steam turbine blade path upgrade. The A.B. Brown Unit 1 steam turbine had a full dense pack upgrade installed in 2012. In 2016, extensive high-pressure/ intermediate-pressure (HP/IP) repairs were made because of a main stop valve bypass failure. Black & Veatch estimates that there would not be any significant improvement with a steam turbine upgrade now, considering the relatively shorter duration since the last steam path upgrade and the potential cost associated with it.

3.2.2 A.B. Brown Unit 2 Steam Turbine Blade Path Upgrades

Black & Veatch reviewed the steam turbine blade path upgrade. The A.B. Brown Unit 2 steam turbine had a full dense pack upgrade installed in 2013. Black & Veatch estimates that there would not be any significant improvement with a steam turbine upgrade now, considering the relatively shorter duration since the last steam path upgrade and the potential cost associated with it.

3.2.3 F.B. Culley Unit 2 Steam Turbine Blade Path Upgrades

The Culley Unit 2 steam turbine is a GE non-reheat steam turbine with a two-flow low-pressure turbine with 20 inch last stage blades. Black & Veatch performed a review of the steam turbine blade path upgrade. As a result of this investigation, two heat balance model of the Culley Unit 2 steam turbine were developed:

- Base: Best match of the Culley Unit 2 Thermal Kit heat balance 328 HB 706 rating flow (guarantee) +5%. (Valve-Wide-Open, Normal Pressure (VWO-NP) case).
- Upgrade Scenario: The entire steam path HP/LP (High-Pressure and Low-Pressure turbines) are upgraded.

This analysis is based on the incremental improvement in steam turbine efficiency, and the differential performance is more important than the absolute performance. The performance improvements and pricing estimates are based on in house data and past project experience. However, steam turbine manufacturers should be contacted to confirm performance and pricing.

3.1.3.1 Base Case

The Base case model is matched to the original thermal kit heat balance 328 HB 706, which is the rating flow (guarantee) +5%. The condenser pressure was set to 1.5 in HgA to keep the basis consistent across the models for comparison against various upgrade options. This Base model was then used to run four cases: Rating flow + 5%, guarantee load (rated pressure and rated flow, corresponding to thermal kit heat balance 332 HB 827), 80% of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 332 HB 829), and 60% of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 332 HB 831).

3.1.3.2 Upgrade Scenario: HP/LP Steam Path Upgrades

In this model, the HP and LP sectional efficiencies were increased from approximately 86.9% and 69.9%, to approximately 87.9% and 71.9% respectively. The advanced age of the Culley Unit 2 steam turbine makes it difficult to estimate exactly how much efficiency could be gained in each section and further analysis should be completed by a steam turbine manufacturer. This model was then used to run four cases: Rating flow + 5%, guarantee load, 80% of guarantee load, and 60% of guarantee load. In each of the cases the boiler steam generation was reduced such that the steam turbine power output matches the value found in the corresponding cases in the original design (STG OEM Thermal Kit).

Tables 3-1 through 3-4 show the results of the turbine modeling conducted by Black & Veatch for this study. For comparison purposes, it was assumed that a boiler efficiency of 88.3% (HHV basis) applies regardless of the magnitude and type of boiler upgrades that may be required. This boiler efficiency is provided by the Vectren data in the Culley Unit 3 snapshot data and was assumed to be the same for Culley Unit 2 for the purposes of this modeling to allow for a comparison between the units.

Table 3-1 Culley Unit 2 Steam Turbine Modeling Results – Rating Flow + 5%

		ORIGINAL HEAT BALANCE	UPGRADE HP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	99,765	99,766
Gross Turbine Heat Rate	Btu/kWh	9,012	8,881
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-131
Turbine Heat Rate Improvement	%	N/A	1.5%
Boiler Heat Input (HHV)	MBtu/h	1,018.4	1,003.6
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-14.8
Boiler Heat Input (HHV) Improvement	%	N/A	1.5%
Gross Plant Heat Rate (HHV)	Btu/kWh	10,208	10,060
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-136
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.5%
*See the explanation above regarding the choice of the boiler efficiency value.			

Table 3-2 Culley Unit 2 Steam Turbine Modeling Results – Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	95,500	95,501
Gross Turbine Heat Rate	Btu/kWh	9,002	8,870
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-131
Turbine Heat Rate Improvement	%	N/A	1.5%
Boiler Heat Input (HHV)	MBtu/h	973.8	959.6
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-14.2
Boiler Heat Input (HHV) Improvement	%	N/A	1.5%
Gross Plant Heat Rate (HHV)	Btu/kWh	10,197	10,048
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-136
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.5%
* See the explanation above regarding the choice of the boiler efficiency value.			

Table 3-3 Culley Unit 2 Steam Turbine Modeling Results – 80% of Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	76,239	76,239
Gross Turbine Heat Rate	Btu/kWh	8,977	8,856
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-121
Turbine Heat Rate Improvement	%	N/A	1.4%
Boiler Heat Input (HHV)	MBtu/h	775.3	764.8
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-10.5
Boiler Heat Input (HHV) Improvement	%	N/A	1.4%
Gross Plant Heat Rate (HHV)	Btu/kWh	10,169	10,032
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-138
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.4%
* See the explanation above regarding the choice of the boiler efficiency value.			

Table 3-4 Culley Unit 2 Steam Turbine Modeling Results – 60% of Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
Gross STG Gross Output	kW	56,672	56,672
Gross Turbine Heat Rate	Btu/kWh	9,133	9,020
Turbine Heat Rate Change	Btu/kWh	N/A	-113
Turbine Heat Rate Improvement	%	N/A	1.2%
Boiler Heat Input (HHV)	MBtu/h	586.3	579.0
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-7.3
Boiler Heat Input (HHV) Improvement	%	N/A	1.2%
Gross Plant Heat Rate (HHV)	Btu/kWh	10,346	10,217
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-129
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.2%
* See the explanation above regarding the choice of the boiler efficiency value.			

The estimate capital cost and HRI for the turbine upgrade option is as follows:

Full Steam Path Upgrade

Total Installed Capital Cost:	$10.4 million
Heat Rate (efficiency) Improvement:	1.3-1.5%

3.1.4 F.B. Culley Unit 3 Steam Turbine Blade Path Upgrades

The F.B. Culley Unit 3 steam turbine is a GE reheat steam turbine with a two-flow LP turbine and 26-inch last stage blade length for the LP end. Black & Veatch reviewed the steam turbine blade path upgrade. As a result of this investigation, heat balance cases were developed for the F.B. Culley Unit 3 steam turbine:[2]

- Base Case: Best match of the F.B. Culley Unit 3 thermal kit heat balance 534 HB 894 (guarantee).
- Upgrade Scenario: The entire HP/IP/LP steam path is upgraded.

This analysis is based on the incremental improvement in steam turbine efficiency, and the differential performance is more important than the absolute performance. The performance improvements and pricing estimates are based on in-house data and past project experience and are believed to be achievable. However, steam turbine manufacturers should be contacted to confirm performance and pricing.

3.1.4.1 Base Case

The Base Case model is matched to the thermal kit heat balance 534 HB 894, which is the guarantee case. The condenser pressure was set to 3.5 in. HgA to keep the basis consistent across the models for comparison against various upgrade options. This Base Case model was then used to run three cases: Guarantee load (rated pressure and rated flow, corresponding to thermal kit heat balance 534 HB 894); 80 percent of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 170X450-21); and 60 percent of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 170X450-22).

3.1.4.2 Upgrade Scenario: HP/IP/LP Steam Path Upgrades

In this model, the HP, IP, and LP sectional efficiencies were increased from approximately 86.7 percent, 88.2 percent, and 89.3 percent to approximately 90 percent, 90 percent, and 92 percent, respectively[3]. This model was then used to run three cases: Guarantee load; 80 percent of guarantee load; and 60 percent of guarantee load. In each of the cases, the boiler steam generation was reduced so that the steam turbine power output matched the values found in the corresponding cases in the original design (STG OEM thermal kit).

---

[2] Additional cases could be evaluated which look at the difference between current performance if the blades and turbine are newly overhauled, versus a new upgrade. Another possibility is developing a map of turbine performance over an expected life between major turbine outages and maintenance activities. Those require more detailed studies which mandate input from the STG OEM with a reference upgrade design, which is beyond the scope of this EPA-ACE analysis.

[3] Based upon OEM data.

Tables 3-5 through 3-7 show the results of the turbine modeling conducted by Black & Veatch for this study. For comparison purposes, it was assumed that a boiler efficiency of 88.3 percent (HHV basis) applies regardless of the magnitude and type of boiler upgrades that may be required.

Table 3-5 F.B. Culley Unit 3 Steam Turbine Modeling Results – Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/IP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	288,360	288,367
Gross Turbine Heat Rate	Btu/kWh	8,219	8,085
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-134
Turbine Heat Rate Improvement	%	N/A	1.6%
Boiler Heat Input (HHV)	MBtu/h	2,684.7	2,640.9
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-43.8
Boiler Heat Input (HHV) Improvement	%	N/A	1.6%
Gross Plant Heat Rate (HHV)	Btu/kWh	9,310	9,158
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-152
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.6%
*This boiler efficiency takes its basis from the F.B. Culley Unit 3 data snapshot, collected on May 27, 2019.			

Table 3-6 F.B. Culley Unit 3 Steam Turbine Modeling Results – 80% of Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/IP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	236,806	236,817
Gross Turbine Heat Rate	Btu/kWh	8,254	8,129
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-125
Turbine Heat Rate Improvement	%	N/A	1.5%
Boiler Heat Input (HHV)	MBtu/h	2,214.1	2,180.7
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-33.4
Boiler Heat Input (HHV) Improvement	%	N/A	1.5%
Gross Plant Heat Rate (HHV)	Btu/kWh	9,350	9,208
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-142
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.5%

*This boiler efficiency takes its basis from the F.B. Culley Unit 3 data snapshot, collected on May 27, 2019.

Table 3-7 F.B. Culley Unit 3 Steam Turbine Modeling Results – 60% of Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/IP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	178,684	178,683
Gross Turbine Heat Rate	Btu/kWh	8,451	8,333
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-118
Turbine Heat Rate Improvement	%	N/A	1.4%
Boiler Heat Input (HHV)	MBtu/h	1,710.6	1,686.7
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-23.9
Boiler Heat Input (HHV) Improvement	%	N/A	1.4%
Gross Plant Heat Rate (HHV)	Btu/kWh	9,573	9,440
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-134
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.4%
*This boiler efficiency takes its basis from the F.B. Culley Unit 3 data snapshot, collected on May 27, 2019.			

The estimate capital cost and HRI for the turbine upgrade options is as follows:

Full Steam Path Upgrade

Total Installed capital cost: $19.9 million

Heat Rate (efficiency) improvement: 1.4-1.6%

3.2 UNIT ECONOMIZER REDESIGN OR UPGRADES

3.2.1 Economizer Upgrades Under EPA ACE

One of the primary BSER under the EPA ACE is the prospect of upgrades to, or even complete replacement of, the economizer. The overarching goal in economizer upgrades or replacement is to improve heat transfer from the flue gas to add heat to the boiler water/steam circuit and, thus, improve boiler efficiency. According to the performance estimates included in the EPA ACE proposal, redesign or replacement of the economizer should yield a heat rate improvement from 0.5 percent to 0.9 percent for units under 200 MW, and from 0.5 percent to 1.1 percent for units ranging from 200 MW to 500 MW. The EPA specifically states that economizer replacements are often avoided because of concerns over triggering New Source Review (NSR); for this reason, the EPA ACE is intended to provide power plants with the flexibility to make these changes.

However, there are many risks associated with redesign or replacement of the economizer:

- Most commonly, projects that consider increasing economizer tube surface area are ones which consider adding tube passes to either the upstream or the downstream portion of the economizer(s). This is because most economizers have a dense tube packing that disallows addition of tube assemblies across the furnace width. However, in the boiler backpass region, space constraints often limit the ability to add more than 2 or 3 tube passes. Thus, making significant changes to the economizer may not be possible at many units.
- Even the addition of a single pass of tubes requires an extended boiler outage; significant construction preparation and welding/tie-in work are required to add tubes to the economizer. The replacement power cost and lost opportunity/contract cost of this outage can be significant if it is not combined with a previously planned outage (such as, for steam turbine upgrades).
- Replacement of entire economizers is not generally done within the industry because of the large expense involved. When it has been undertaken in recent years, the most common reasons are either to replace a badly eroded economizer, or to replace an economizer with spiral-finned tubes with one with bare tubes to reduce tube fouling (especially after conversions to Powder River Basin coals).
- Changing tube surface area will often change the balance of heat transfer between the radiative and connective sections, as well as the main steam and reheat steam circuitry. This is especially true in the case of units that employ a split backpass design with gas biasing reheat control. Prediction of the complex interactions between the water, main steam, and reheat steam circuits in both the radiative and convective sections typically requires detailed boiler modeling.
- Adding tube surface to an economizer will reduce the flue gas temperature exiting the economizer, which could reduce operations flexibility if an SCR is positioned downstream of the economizer. Reduced flue gas temperatures will increase the minimum load possible with the SCR in service and could require a system such as an economizer gas bypass or in-duct burners to allow for SCR operation with these reduced temperatures. Both of these reparative measures will worsen the plant heat rate, thus negating the benefit of the upgraded economizer.
- Reduced flue gas temperatures entering the air heater will help improve the overall boiler efficiency but can also lead to operations problems should the cold-end average temperature be reduced below the recommended point for the type of fuel that is being burned and its sulfur content. In addition, ammonium bisulfate deposition can be increased in some cases where the flue gas inlet temperature at the air heaters is reduced from normal.
- In some cases, flue gas temperatures could be reduced to the point where other downstream air quality control equipment (such as an electrostatic precipitator or fabric filter baghouse) could be at risk for corrosion damage.

- While it is possible to add an economizer downstream of the SCR system to reduce the impact on the flue gas temperature entering the SCR, such installations are unusual and often require variable water bypass circuitry to maintain good temperature control.

Assessment of the ability of a unit to accommodate changes in the economizer tube surface area typically requires plant modeling of some sort, whether utilizing a combined first-principles and empirical model (such as the Electric Power Research Institute's [EPRI's] Vista program), or even a highly detailed (and expensive) computation fluid dynamics model of the entire boiler circuit and downstream affected equipment. The following section is a high-level overview of economizer upgrades, while the further sections provide more detail through the use of Vista modelling software.

Cost estimation for economizer upgrades is highly variable and depends on the amount of work conducted, the site spacing and access, other boiler or plant modifications that are required, etc. The EPA ACE rule advises in Table 2 that the cost to redesign or replace an economizer can be up to $3.74 million for a 200 MW unit or up to $6.35 million for a 500 MW unit.

3.2.2 A.B. Brown Units 1 and 2 Economizer Redesign or Upgrades

Plant personnel report that because of low SCR inlet temperatures, A.B. Brown Units 1 and 2 require natural gas duct burners to be operated to maintain temperatures over the minimum SCR inlet temperature of 625° F. An example of the gas duct burner operation as a function of gross output is shown for Unit 1 on Figure 3-1.

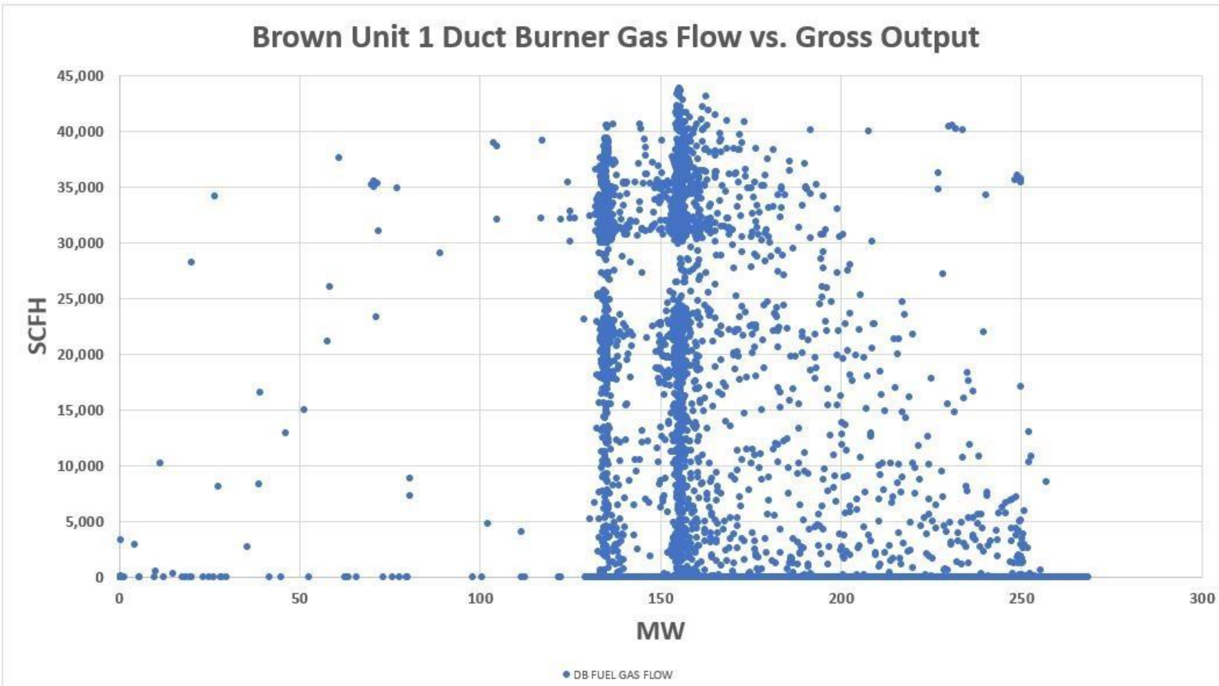


Figure 3-1 A.B. Brown Unit 1 Economizer Gas Flow vs. Gas Outlet

Plant personnel stated that the high gas use of the duct burners is a concern from a heat rate standpoint, although, unlike the case of F.B. Culley Unit 3, there was no estimate on the overall annual heat rate impact. Given this situation at A.B. Brown Units 1 and 2, adding economizer tube surface area is not recommended at this time. It is possible that reducing the economizer tube surface area could improve the plant heat rate by reducing the natural gas usage, and a next-phase study could easily determine this by employing coordinated plant modeling with a boiler-SCR-air heater model across the typical operating load ranges of the units.

3.2.3 F.B. Culley Unit 2 Economizer Redesign or Upgrades

F.B. Culley Unit 2 has maintained its original economizer design, and as it does not have an SCR system, it does not suffer from the constraint of reduced flue gas temperatures limiting operation. As a result, it is possible that economizer modifications could result in a significant heat rate benefit to the unit, especially as the F.B. Culley Unit 2 economizer gas outlet temperature appears to be high at higher loads (over 700° F at times). Refer to Figure 3-2.

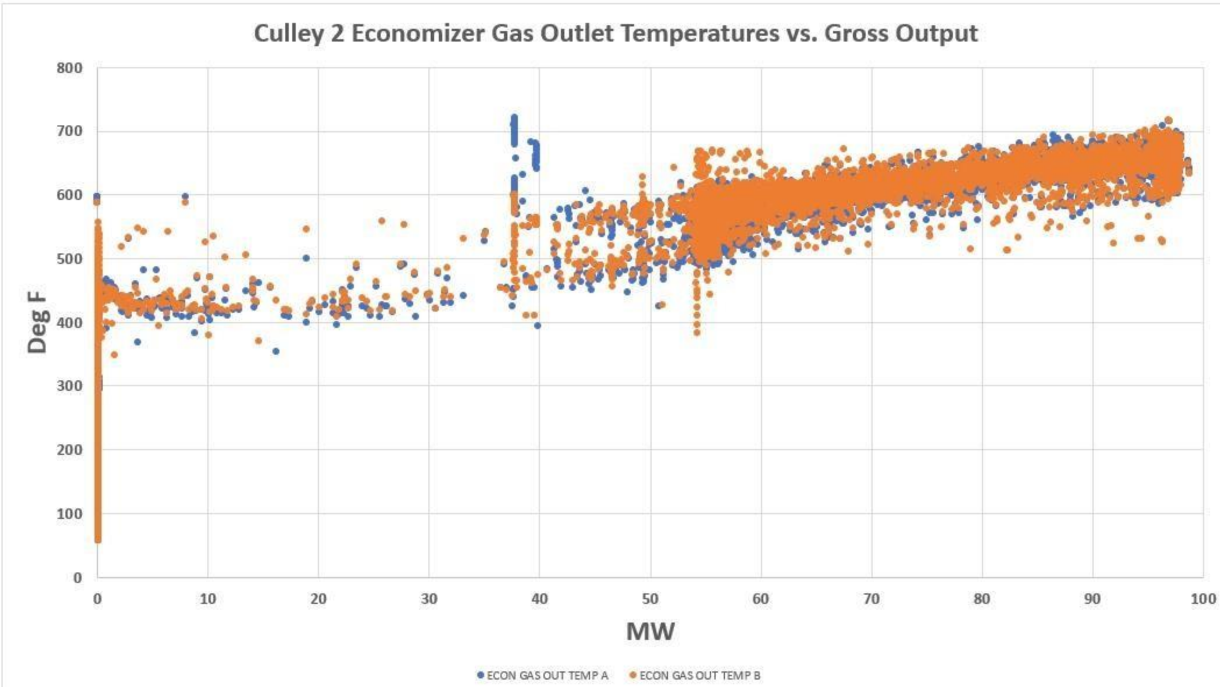


Figure 3-2 F.B. Culley Unit 2 Economizer Gas Outlet Temperature Versus Gross Output

The estimated costs and logistics of such a change to the economizers requires significant investigation as a next-phase effort. Assuming no header relocation is needed, and neglecting the loss of contract availability, such a cost is estimated at about $40,000 to 50,000 per British thermal unit per kilowatt-hour (Btu/kWh) for the improvement, or between $2 million to $4 million. For a small, non-reheat unit such as F.B. Culley Unit 2, such an investment may not be warranted at this juncture unless the unit was expected to operate for a significant length of time so that a sufficient payback period could be realized. When the expected future load factor and remaining plant life are taken into account, it is nearly impossible to justify an investment in this area of the plant.

3.2.4 F.B. Culley Unit 3 Economizer Redesign or Upgrades

According to plant personnel, the F.B. Culley Unit 3 economizer was replaced in 1994 with a tube configuration that had additional tube surface area relative to the original design. The goal of this upgrade was to reduce flue gas exit temperatures and improve cycle efficiency, and in that respect, it was successful. However, when the SCR system was added in 2003, the lower flue gas temperatures exiting the economizer resulted in the need for natural gas duct burners to maintain the minimum SCR flue gas inlet temperature of 625° F. The economizer was replaced again in 2008 but was not changed to the original design because of concerns about triggering NSR. Refer to Figure 3-3.

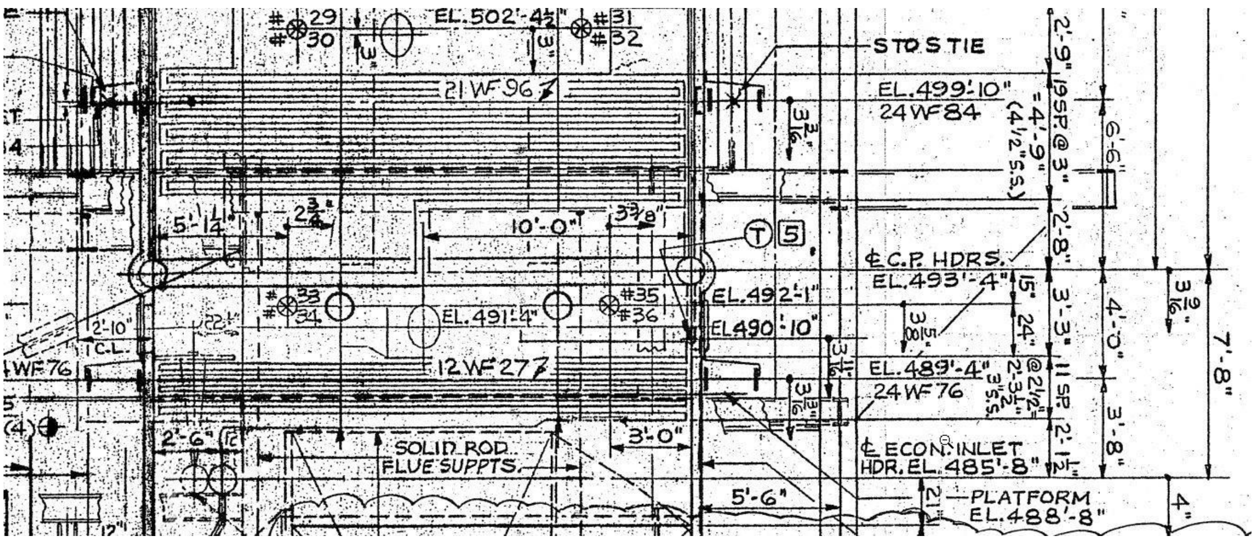


Figure 3-3 F.B. Culley Unit 3 Original Economizer Design

F.B. Culley Unit 3 is required to utilize significant amounts of natural gas via in-duct burners upstream of the SCR system to maintain SCR operating temperatures at anything less than 75 to 80 percent of full load. A plot of operational data, comparing the natural gas burner fuel flow rate versus the unit gross output, is shown by Figure 3-4.

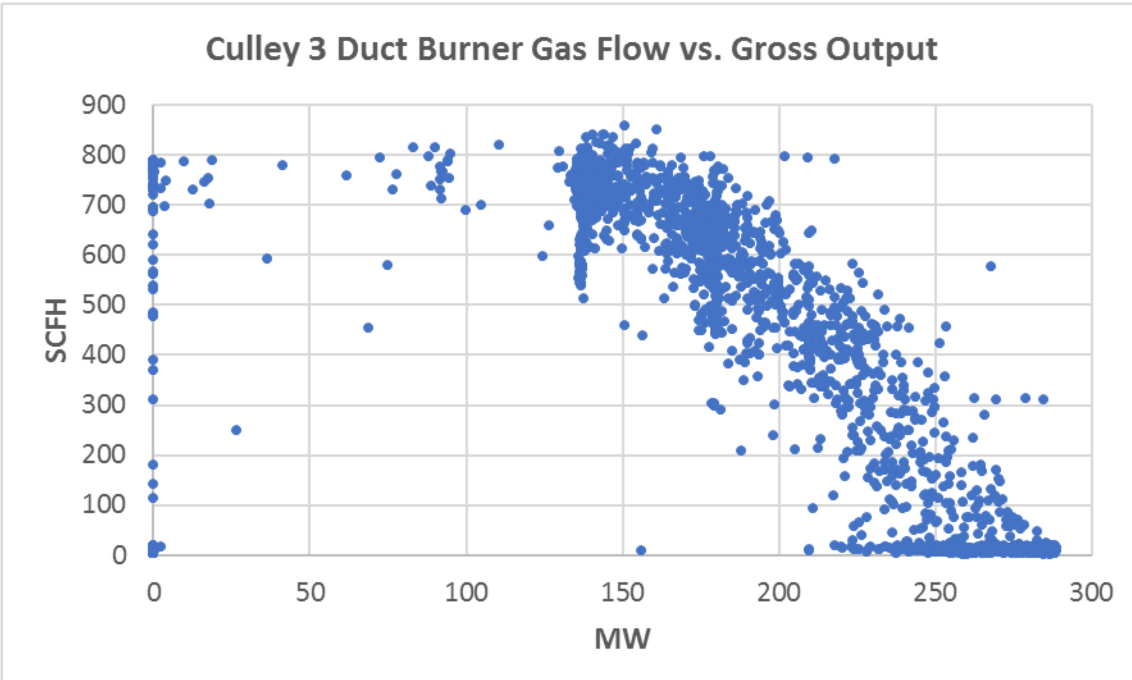


Figure 3-4 F.B. Culley Unit 3 Duct Burner Gas Flow Versus Gross Output

Given this situation at F.B. Culley Unit 3, adding economizer tube surface area is not recommended at this time. It is possible that reducing the economizer tube surface area could improve the plant heat rate by reducing the natural gas usage, and a next-phase study could easily determine this by employing coordinated plant modeling with a boiler-SCR-air heater model across the typical operating load ranges of the units. Plant personnel report that natural gas heat input to the duct burners comprised nearly 2 percent of the total heat input to the unit for 2018 and 2019 to date.

3.2.5 Economizer Analysis using Vista

Based on the analysis and discussion in the above sections, an analysis of the benefit of reducing natural gas flow to the duct burners by reducing the size of the economizer section was performed for A.B. Brown 1 and F.B. Culley 3. To assess the economizer, Black &Veatch created a base case and then investigated three options: removing 1, 2, and 3 tube passes.

Using data provided by Vectren engineering personnel, an EPRI Vista fuel quality impact model was created for A.B. Brown 1 and F.B. Culley 3. The Vista program contains a detailed linear heat transfer model that has the power to conduct "what if" analyses upon tube banks surface area configurations, and this model was utilized successfully for this study. Several simulations of tube configurations that would decrease the heat transfer area of the economizer were analyzed, and these are detailed in this section. A schematic of the current economizer for A.B. Brown 1 is depicted below (F.B. Culley 3 is depicted in Figure 3-3):

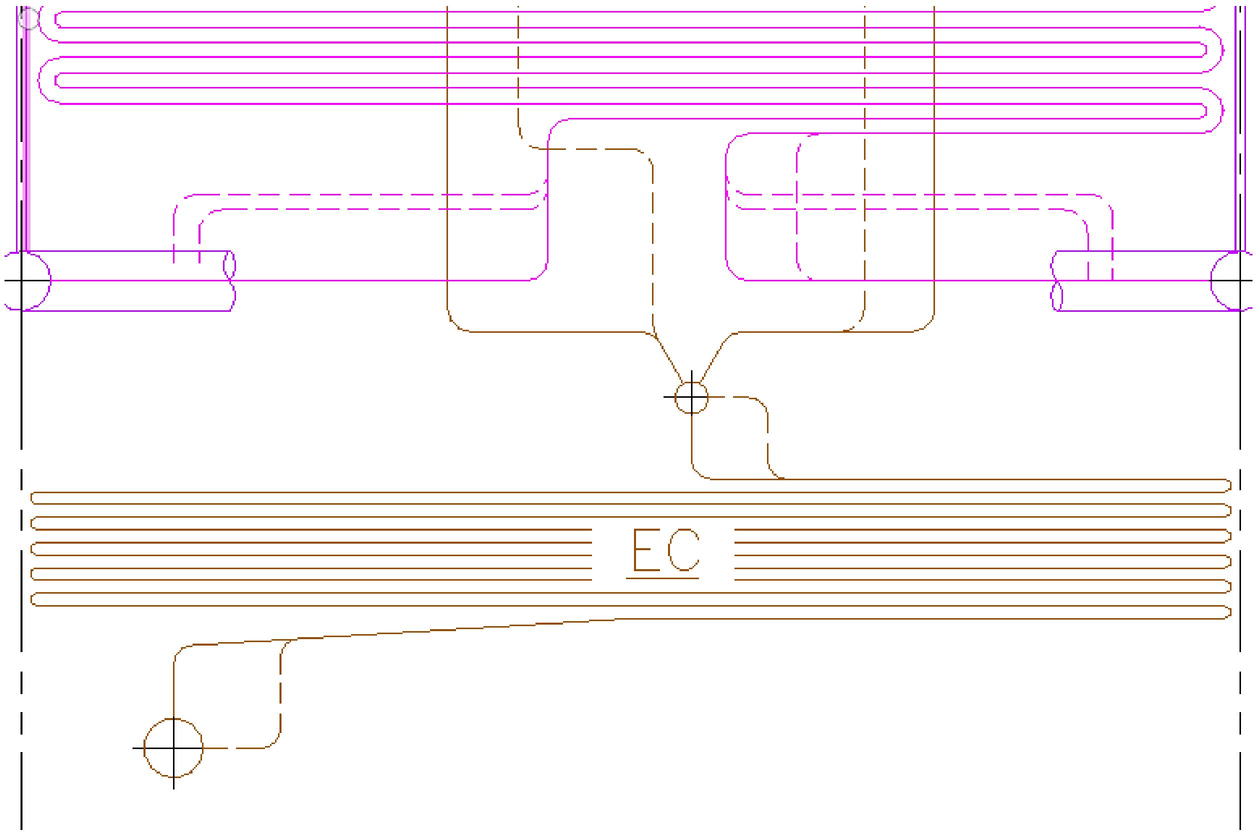


Figure 3-5 A.B. Brown 1 Economizer

3.2.5.1 A.B. Brown Units 1 and 2 Economizer Analysis Results

After calibrating the Vista model of A.B. Brown 1 to 264 MW gross from data collected on August 9, 2018, the following scenarios were run, with the following results.

- Baseline case – SCR inlet temperature = 651 °F.
- Removing 1 pass to the lower economizer – SCR inlet temperature = 662 °F.
- Removing 2 pass to the lower economizer – SCR inlet temperature = 675 °F.
- Removing 3 passes to the lower economizer – SCR inlet temperature = 690 °F.

The results above were from running the model at full load. The graph below shows the unit load vs. the duct burner natural gas flow.

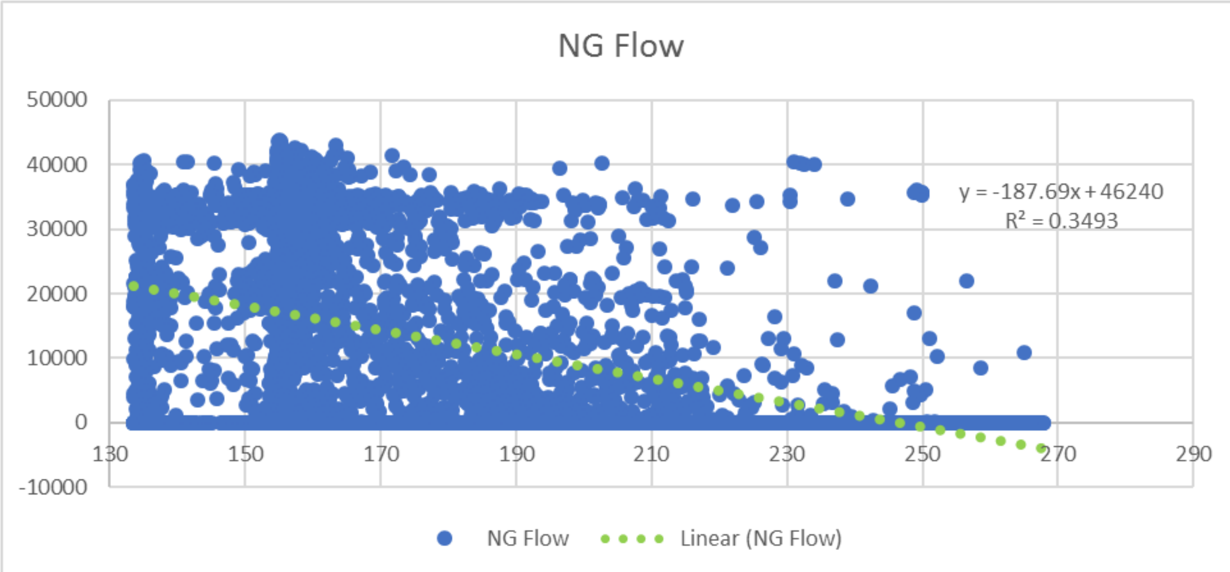


Figure 3-6 Load vs. Temperature and Flow

Linear regression was used to determine the natural gas flow; however, the correlation between natural gas flow and load was poor (R^2 of 0.35). This may warrant further investigation into the measurement or control methodology of the natural gas flow for the duct burners. Also, A.B. Brown 1 does not have an online measurement for the economizer flue gas outlet temperature. If this temperature was measured and tracked in the data historian, it would significantly improve the analysis of the data.

This reduction in economizer surface area comes at a cost in heat rate. From the analysis a reduction in the economizer surface area produces the following heat rate impacts on an overall basis:

- Baseline case – 0% difference.
- Removing 1 pass to the lower economizer – 0.17 % worsening.
- Removing 2 passes to the lower economizer – 0.36 % worsening.
- Removing 3 passes to the lower economizer – 0.61 % worsening.

This heat rate impact had the following effects on fuel burn rate at full load:

- Removing 1 pass to the lower economizer – 4.23 MMBtu/hr increase.
- Removing 2 passes to the lower economizer – 8.91 MMBtu/hr increase.
- Removing 3 passes to the lower economizer – 15.06 MMBtu/hr increase.

Should a change be made to the economizer tube surface area, the estimated costs and logistics of such a change to the economizers, assuming no header relocation is needed and neglecting the loss of contract availability, are expected to range from $750,000 to $1,400,000 depending upon the amount of modification. Complete replacement of the economizer was not estimated during this effort, nor was any addition to hot reheat surface or any other modifications.

3.2.5.2 F.B. Culley Unit 3 Economizer Analysis Results

After calibrating the Vista model of F.B. Culley 3 to 286 MW gross from data collected on May 27, 2019, the following scenarios were run, with the following results.

- Baseline case – SCR inlet temperature = 649 °F.
- Removing 1 pass to the lower economizer – SCR inlet temperature = 656 °F.
- Removing 2 pass to the lower economizer – SCR inlet temperature = 663 °F.
- Removing 3 passes to the lower economizer – SCR inlet temperature = 670 °F.

The results above were from running the model at full load. The graph below shows unit load vs. SCR inlet temperature, economizer gas outlet temperature, and duct burner natural gas flow. The delta-temperature below the minimum acceptable SCR inlet temperature of 625 °F was also plotted.

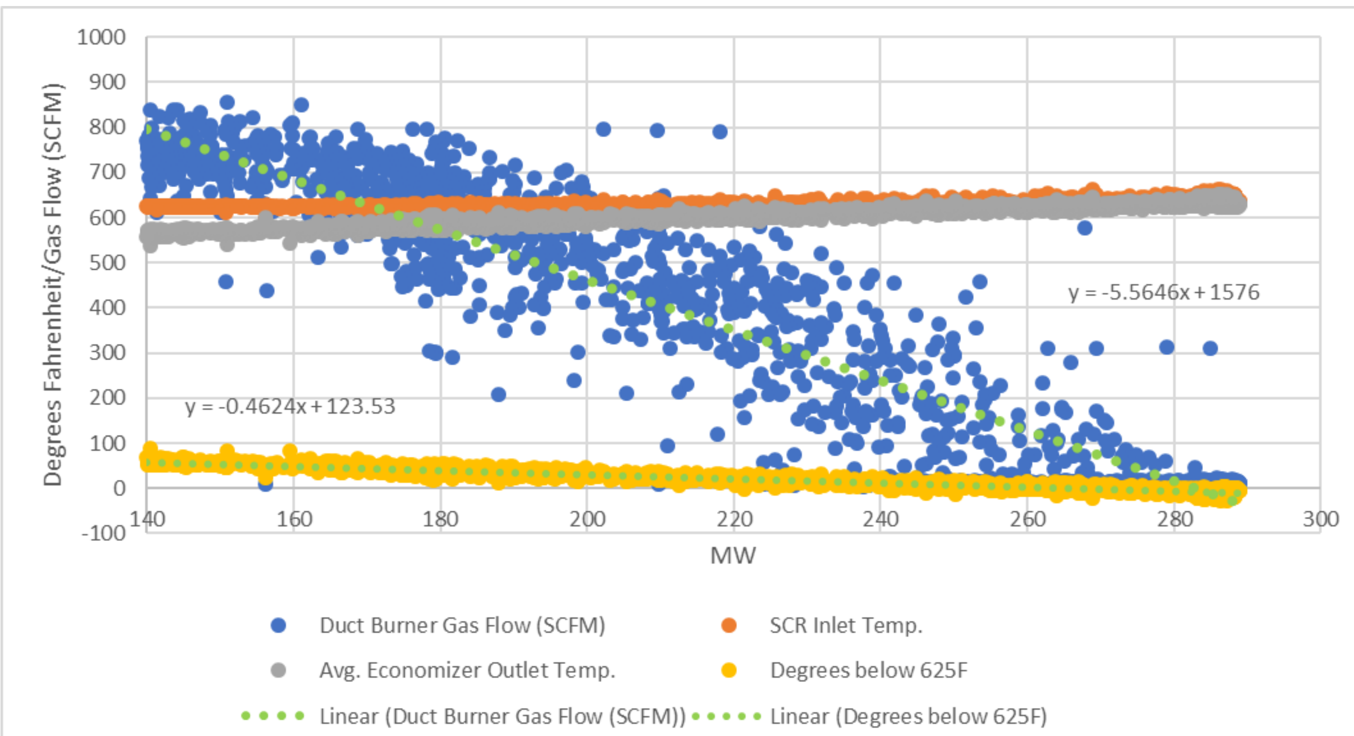


Figure 3-7 Load vs. Temperature and Flow

Using linear regression, the temperature difference calculated from Vista was used to determine new loads without using the duct burner and the gas flow savings for each economizer pass reduction"

- Removing 1 pass to the lower economizer – New load without duct burner use - 252MW, Gas Flow savings - 174 SCFM (10.6 MMBtu).

- Removing 2 passes to the lower economizer – New load without duct burner use- 237MW, Gas Flow savings - 257 SCFM (15.7 MMBtu).
- Removing 3 passes to the lower economizer – New load without duct burner use- 222MW, Gas Flow savings - 341 SCFM, (20.8 MMBtu).

This reduction does come at a cost in heat rate. From the analysis a reduction in the economizer surface area produces the following heat rate impacts on an overall basis:

- Baseline case – 0% difference.
- Removing 1 pass to the lower economizer - 0.14% worsening.
- Removing 2 passes to the lower economizer – 0.28% worsening.
- Removing 3 passes to the lower economizer – 0.43% worsening.

This heat rate impact had the following effects on fuel burn rate at full load:

- Removing 1 pass to the lower economizer – 3.22 MMBtu/hr increase.
- Removing 2 passes to the lower economizer – 6.6 MMBtu/hr increase.
- Removing 3 passes to the lower economizer – 10.16 MMBtu/hr increase.

From examining the results listed above, removing a portion of the economizer would results in an energy savings. Given the cost differential of $3.00 per MMBtu for natural gas compared to Vectren’s $2.22 per MMBtu for coal, the savings in natural gas flow at full load would be approximately $5.76 per hour for the 1 pass case and $8.30 per hour for the 3-pass case. Assuming that savings would be realized over 70% of the year (8760 hours). This would result in $151k in savings for the first year for the base case and $244k in savings for the first year for the alternate case.

Should a change be made to the economizer tube surface area, the estimated costs and logistics of such a change to the economizers, assuming no header relocation is needed and neglecting the loss of contract availability are expected to range from $750,000 to $1,400,000 depending upon the amount of modification. Complete replacement of the economizer was not estimated during this effort, nor was any addition to hot reheat surface or any other modifications.

3.3 AIR HEATER AND LEAKAGE CONTROL UPGRADES

A core opportunity for net plant heat rate (NPHR) improvement is solidifying the operational reliability and process integrity of the combustion air draft system and flue gas draft system. The gas-to-air regenerative air heaters are a critical nexus between these two subsystems. Similarly, balanced draft units are susceptible to the effects of air in-leakage in the flue gas draft system because of the negative (internal) operating pressure of the flue gas ductwork. The following sections outline the NPHR improvement initiatives targeting the existing regenerative air heaters and mitigating the detrimental effects of flue gas draft system duct air in-leakage. The A.B.

Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3 considerations are addressed in the following sections.

3.3.1 A.B. Brown Unit 1 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades is due to reducing the duty of the unit's combustion air and flue gas induced draft fans, thus reducing the unit's overall auxiliary load.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas and causing corrosive flue gas acid gasses to condense on air heater cold end baskets and ductwork components. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair and reduce operation and maintenance (O&M) costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow, potentially reducing the life expectancy of pulse jet fabric filter (PJFF) bags.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be closer to acid dew point and increasing the potential for equipment corrosion throughout the flue gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of HRI projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefits. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

3.3.1.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas induced draft fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reduce the temperature of the flue gas, and increase the mass and volumetric flow of the flue gas, which results in a higher flue gas-induced draft fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The two air heaters of A.B. Brown Unit 1 are regenerative Ljungström type air heaters with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The A.B. Brown Unit 1 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. Prior to the SCR installation, the original design air leakage for the A.B. Brown Unit 1 air heaters was approximately 7 percent to 8 percent. The installation of the SCR units has resulted in a corresponding increase of the full load air-to-gas side differential pressure by several inches of water column (when combustion air and flue gas pressures are compared). Additionally, the hot end sector plates have been replaced for A.B. Brown Unit 1, and the OEM recommendation is to replace the cold-end sectors plates. Air heater leakage is closely monitored for A.B. Brown Unit 1 because of the detrimental effect of oxygen on the dual alkali scrubbers within the air quality control system (AQCS).

According to feedback from Vectren operations personnel, positive contact seals have been attempted for the A.B. Brown Unit 1 air heaters in the past but were removed from service because of failures during operation. The air heaters now utilize the original seal types. More frequent in situ monitoring or installation of permanent probes measuring flue gas oxygen content at the induced draft (ID) fan inlet would allow for more accurate trending of the air in-leakage over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate due to dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency as the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent. To achieve this, upgrades to the air preheat system and air-side and/or gas-side air heater bypasses would likely be required to maintain air heater gas outlet temperatures above the acid dew point at lower loads and during colder times of the year.

It should be noted that internal air heater condition should also be assessed to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the A.B. Brown Unit 1 air heaters is the potential reduction of the air heater cold-end setpoint temperature for A.B. Brown Unit 1.

According to unit operating data provided by Vectren, A.B. Brown Unit 1 maintains a consistent air heater cold-end temperature near 325 to 330° F (measured at the ID fan inlet for A.B. Brown Unit 1). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature, which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to setpoints within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages. While plant personnel report that generally speaking dew point temperatures have not been a problem at the unit, they nonetheless would be concerned about any significant reduction in air heater gas outlet temperature which takes the unit into an unfamiliar operating regime.

Air heater bypasses have been installed on the A.B. Brown Unit 1 draft system. This system provides a backup for the existing air preheating steam coil systems for cold-end temperature control for periods of extreme cold weather or a coil being taken out of service. Upgrades to the steam coil system would allow for fewer uses of the air heater (air-side) bypass during the year and fewer instances of the associated heat rate penalty during the intermittent use of the bypass.

3.3.1.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system, and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas ID fan auxiliary load, thus negatively impacting the unit's NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion.

The ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The A.B. Brown Unit 1 forecast for scheduled maintenance outages is outlined in Table 3-8.

Table 3-8 A.B. Brown Unit 1 O&M Scheduled Outage Intervals (2020-2039)

YEAR	A.B. BROWN UNIT 1 O&M - SCHEDULED OUTAGE
2020	--
2021	3 weeks
2022	Major
2023	--
2024	3 weeks
2025	3 weeks
2026	--
2027	3 weeks
2028	3 weeks
2029	--
2030	3 weeks
2031	Major
2032	--
2033	3 weeks
2034	3 weeks
2035	--
2036	3 weeks
2037	3 weeks
2038	--
2039	3 weeks

To determine the overall cost associated with improving the ductwork leakage rates, field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air forced draft/primary air [FD/PA]) fans or areas closer to the inlet of the flue gas induced draft fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Draft system leakage testing data for A.B. Brown Unit 1 were not available for review or incorporation into this analysis. Therefore, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities can be implemented to improve the existing air heater units and find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits would likely increase.

Air Heater Basket, Seal, and Sector Plate Replacement

Total Installed Capital Cost:	$850,000
Heat Rate (efficiency) Improvement:	0.5% (assumes 20 °F air heater gas outlet temperature improvement)

Air Preheater (Steam Coil) System Repairs

Total Installed Capital Cost:	$350,000
Heat Rate (efficiency) Improvement:	0.1% (applicable to intermittent periods when steam coils would be used)

3.3.2 A.B. Brown Unit 2 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades results from reducing the duty of the unit's combustion air and flue gas induced draft fans, thus reducing the unit's overall auxiliary load demand.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas and causing corrosive flue gas acid gasses to condense on air heater cold end baskets and ductwork components, resulting in degradation of equipment materials. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair, and reduce O&M costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow reducing the ability of an electrostatic precipitator to capture ash.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be

closer to acid dew point increasing the potential for equipment corrosion throughout flue gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of heat rate improvement projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefit. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

3.3.2.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas ID fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reducing the temperature of the flue gas, and increasing the mass and volumetric flow of the flue gas, resulting in a higher flue gas ID fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The two air heaters of A.B. Brown Unit 2 are regenerative Ljungström type air heaters with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The A.B. Brown Unit 2 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. Prior to the SCR installation, the original design air leakage for the A.B. Brown Unit 2 air heaters was approximately 7 to 8 percent. The installation of the SCR units has resulted in a corresponding increase of the full load air-to-gas side differential pressure by several inches of water column (when combustion air and flue gas pressures are compared). Additionally, the hot end sector plates have been replaced for A.B. Brown Unit 2, and the OEM recommendation is to replace the cold-end sectors plates. Air heater leakage is closely monitored for A.B. Brown Unit 2 because of the detrimental effect of oxygen on the dual alkali scrubbers within the AQCS.

According to feedback from Vectren operations personnel, positive contact seals have been attempted for the A.B. Brown Unit 2 air heaters in the past but were removed from service because of failures during operation. The air heaters now utilize the original seal types. More frequent in-situ monitoring or installation of permanent probes measuring flue gas oxygen content at the ID fan inlet would allow for more accurate trending of the air in-leakage trends over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate due to dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency as the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent. Upgrades to the air preheat system and air-side and/or gas-side air heater bypasses are expected to be likely, however, to maintain air heater gas outlet temperatures above the acid dew point at lower loads and during colder times of the year.

It should be noted that internal air heater condition should also be assessed to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the A.B. Brown Unit 2 air heaters is the potential reduction of the air heater cold-end setpoint temperature for A.B. Brown Unit 2.

According to unit operating data provided by Vectren, A.B. Brown Unit 2 maintains a consistent air heater cold-end temperature near 325 to 330° F (measured at the ID fan inlet for A.B. Brown Unit 2). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature, which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to setpoints within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages.

Air heater bypasses have been installed on the A.B. Brown Unit 2 draft system. This system provides a backup for the existing air preheating steam coil systems for cold-end temperature control for periods of extreme cold weather or a coil being taken out of service. Upgrades to the steam coil system would allow for fewer uses of the air heater (air-side) bypass during the year and fewer instances of the associated heat rate penalty during the intermittent use of the bypass.

3.3.2.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas ID fan auxiliary load, thus negatively impacting the unit's NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion.

Ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The A.B. Brown Unit 2 forecast for scheduled maintenance outages is outlined in Table 3-9.

Table 3-9 A.B. Brown Unit 2 O&M Scheduled Outage Intervals (2020-2039)

YEAR	A.B. BROWN UNIT 2 O&M - SCHEDULED OUTAGE
2020	3 weeks
2021	3 weeks
2022	--
2023	Major
2024	3 weeks
2025	--
2026	3 weeks
2027	3 weeks
2028	--
2029	3 weeks
2030	3 weeks
2031	--
2032	3 weeks
2033	Major
2034	--
2035	3 weeks
2036	Major
2037	--
2038	3 weeks
2039	Major

To determine the overall cost associated with improving the ductwork leakage rates field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air fans or areas closer to the inlet of the flue gas ID fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Draft system leakage testing data for A.B. Brown Unit 2 were not available for review/incorporation into this analysis. Therefore, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities can be implemented to improve the existing air heater units and find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits could likely increase.

Air Heater Basket, Seal, and Sector Plate Replacement

Total Installed Capital Cost:	$850,000
Heat Rate (efficiency) Improvement:	0.5% (assumes 20° F air heater gas outlet temperature improvement)

Air Preheater (Steam Coil) System Repairs

Total Installed Capital Cost:	$350,000
Heat Rate (efficiency) Improvement:	0.1% (applicable to intermittent periods when steam coils would be used)

3.3.3 F.B. Culley Unit 2 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades is a result of reducing the duty of the unit's combustion air and flue gas induced draft fans, thus reducing the unit's overall auxiliary load demand.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas, causing corrosive flue gas acid gases to condense on air heater cold end baskets and ductwork components. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair, and reduce O&M costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow, potentially reducing the life expectancy of PJFF bags.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak by of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be closer to acid dew point and increasing the potential for equipment corrosion throughout flue the gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of heat rate improvement projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefit. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

3.3.3.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas ID fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reducing the temperature of the flue gas, and increasing the mass and volumetric flow of the flue gas, resulting in a higher flue gas ID fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The F.B. Culley Unit 2 air heater is a regenerative Ljungström type air heater with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The F.B. Culley Unit 2 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. More frequent in situ monitoring or installation of permanent probes measuring flue gas oxygen content at the ID fan inlet would allow for more accurate trending of the air in-leakage over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate from a dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency because the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent.

The F.B. Culley Unit 2 air preheater (steam coil) units are reportedly in good condition and operate reliably; because of this, there were no recommendations or perceived improvements to unit performance as a result of additional capital budget spending for the air preheater units.

It should be noted that an internal air heater conditional assessment should also be made to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the F.B. Culley Unit 2 air heaters is the potential reduction of the air heater cold-end setpoint temperature for F.B. Culley Unit 2.

According to unit operating data provided by Vectren, F.B. Culley Unit 2 maintains a consistent air heater cold-end temperature near 325 to 330°F (measured at the ID fan inlet for F.B. Culley Unit 2). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature, which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to setpoints within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages.

3.3.3.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system, and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas induced draft fan auxiliary load, thus negatively impacting the units NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion.

Ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The F.B. Culley Unit 2 forecast for scheduled maintenance outages is outlined in Table 3-10.

Table 3-10 F.B. Culley Unit 2 O&M Scheduled Outage Intervals (2020-2039)

YEAR	F.B. CULLEY UNIT 2 O&M - SCHEDULED OUTAGE
2020	3 weeks
2021	--
2022	3 weeks
2023	--
2024	Major
2025	--
2026	3 weeks
2027	--
2028	3 weeks
2029	--
2030	3 weeks
2031	--
2032	3 weeks
2033	--
2034	Major
2035	--
2036	3 weeks
2037	--
2038	3 weeks
2039	--

To determine the overall cost associated with improving the ductwork leakage rates field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air fans or areas closer to the inlet of the flue gas ID fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Draft system leakage testing data for F.B. Culley Unit 2 were not available for review or incorporation into this analysis. Therefore, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities can be implemented to improve the existing air heater units and find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits would likely increase.

Air Heater Basket, Seal, and Sector Plate Replacement

Total Installed Capital Cost:	$476,000
Heat Rate (efficiency) Improvement:	0.5% (assumes 20° F air heater gas outlet temperature improvement)

3.3.4 F.B. Culley Unit 3 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades is as a result of reducing the duty of the unit's combustion air and flue gas induced draft fans thus reducing the units overall auxiliary load demand.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas, causing corrosive flue gas acid gases to condense on air heater cold end baskets and ductwork components. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair, and reduce O&M costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow, potentially reducing the life expectancy of PJFF bags.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak-by of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be closer to acid dew point and increasing the potential for equipment corrosion throughout the flue gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of heat rate improvement projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefit. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

3.3.4.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas ID fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reducing the temperature of the flue gas, and increasing the mass and volumetric flow of the flue gas, resulting in a higher flue gas ID fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The two air heaters of F.B. Culley Unit 3 are regenerative Ljungström type air heaters with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The F.B. Culley Unit 3 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. Prior to the SCR installation, the original design air leakage for the F.B. Culley Unit 3 air heaters was approximately 7 to 8 percent. The installation of the SCR units has resulted in a corresponding increase of the full load air-to-gas side differential pressure by several inches of water column (when combustion air and flue gas pressures are compared).

Air in-leakage testing (measuring the oxygen content rise in discrete sections of the F.B. Culley Unit 3 draft system) was performed in 2017. This testing indicated a 16 to 17 percent leakage across each of the F.B. Culley Unit 3 air heaters (with the unit at full load). The leakage data across the PJFF and SCR units indicated no significant air infiltration. These data are outlined in Table 3-11 and Figure 3-8.

Table 3-11 F.B. Culley Unit 3 Draft System and Air Heater Air In-Leakage Test Data (July 2017)

TESTING LOCATION	DESCRIPTION	F.B. CULLEY UNIT 3 DRAFT SYSTEM – WEST SIDE	F.B. CULLEY UNIT 3 DRAFT SYSTEM – EAST SIDE
SCR Inlet	SCR inlet after duct burner; duct burner out of service at during full load test	4.0	3.5
SCR Outlet	SCR outlet/AH inlet duct section	4.0	3.7
AH Outlet	AH outlet/PJFF inlet duct section	6.4	6.3
FF Outlet	PJFF outlet/ID fan inlet(s) duct section	6.5	6.2
Calculated AH Leakage (%)	Calculated from "SCR Out" and "AH Out" data provided above	16.9	17.8
AH - air heater			

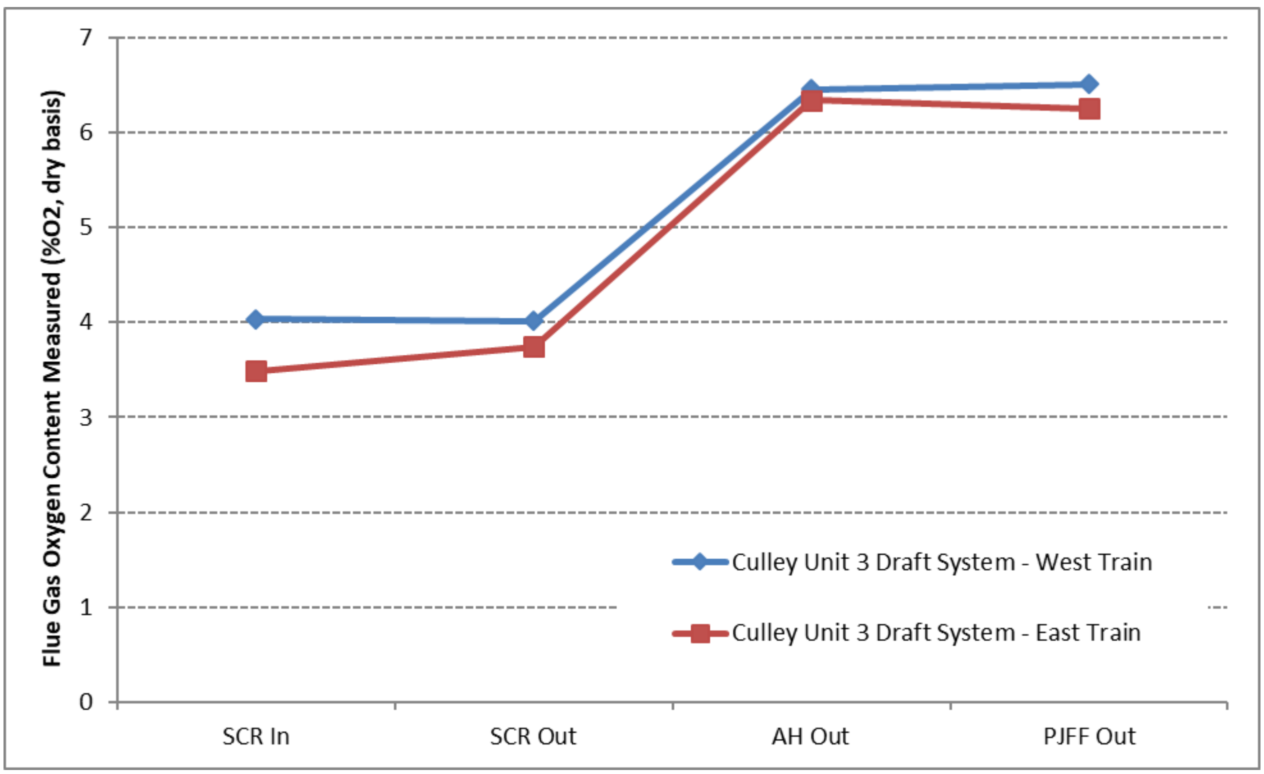


Figure 3-8 F.B. Culley Unit 3 Draft System Air Leakage Test Data (July 2017)

As a result of the air heater leakage test data, all sector plates and seals were replaced at the recommendation of the OEM during the recently completed 2019 planned outage for F.B. Culley Unit 3.

More frequent in situ monitoring or installation of permanent probes measuring flue gas oxygen content at the ID fan inlet would allow for more accurate trending of the air in-leakage over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate due to dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency as the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent. The F.B. Culley Unit 3 air preheater (steam coils) are located in the FD fan room to maintain a minimum air inlet temperature setpoint, controlled by the FD fan outlet temperature. To achieve this, upgrades to the air preheat system and air-side and/or gas-side air heater bypasses would likely be required to maintain air heater gas outlet temperatures above the acid dew point at lower loads and during colder times of the year.

It should be noted that internal air heater condition should also be assessed to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the F.B. Culley Unit 3 air heaters is the potential reduction of the air heater cold-end setpoint temperature.

According to unit operating data provided by Vectren, F.B. Culley Unit 3 maintains a consistent air heater cold-end temperature near 325 to 330° F (measured at the ID fan inlet for F.B. Culley Unit 3). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to set points within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages.

Air heater bypasses have been installed on the F.B. Culley Unit 3 draft system. This system provides a backup for the existing air preheating steam coil systems for cold-end temperature control for periods of extreme cold weather or a coil being taken out of service. Upgrades to the steam coil system would allow for fewer uses of the air heater (air-side) bypass during the year and fewer instances of the associated heat rate penalty during the intermittent use of the bypass.

In October 2018, Ljungström (F.B. Culley Unit 3 air heater OEM, a division of Arvos Group) provided information regarding a proposed air heater upgrade to improve heat rate as part of Vectren's ongoing heat rate improvement initiatives. According to a preliminary review of Ljungström's proposed air heater upgrade options, a 0.4 percent heat rate improvement was estimated. Black & Veatch recommends additional review of the proposed upgrades and potential balance-of-plant impacts (ID fan, ductwork, etc.). The basis of this improvement is relocating the DSI system upstream of the air heater, which would also need to be considered in the project costs.

3.3.4.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system, and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas induced draft fan auxiliary load, thus negatively impacting the unit's NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion. Information provided to assess the flue gas duct work leakage is provided in Table 3-11 and Figure 3-8 above.

Ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The F.B. Culley Unit 3 forecast for scheduled maintenance outages is outlined in Table 3-12.

Table 3-12 F.B. Culley Unit 3 O&M Scheduled Outage Intervals (2020-2039)

YEAR	F.B. CULLEY UNIT 3 O&M - SCHEDULED OUTAGE
2020	3 weeks
2021	--
2022	3 weeks
2023	3 weeks
2024	--
2025	3 weeks
2026	Major
2027	--
2028	3 weeks
2029	3 weeks
2030	--
2031	3 weeks
2032	3 weeks
2033	--
2034	3 weeks
2035	Major
2036	--
2037	3 weeks
2038	3 weeks
2039	--

To determine the overall cost associated with improving the ductwork leakage rates, field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air fans or areas closer to the inlet of the flue gas ID fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Because the age of the previous leakage testing data and the subsequent air heater maintenance performed by Vectren, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities described in this section can be implemented to continue to find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits would likely increase.

Air Heater Basket, Seal, and Sector Plate Replacement

Total Installed Capital Cost:	$750,000
Heat Rate (efficiency) Improvement:	0.5% (assumes 20° F air heater gas outlet temperature improvement)

Air Preheater (Steam Coil) System Repairs

Total Installed Capital Cost:	$350,000
Heat Rate (efficiency) Improvement:	0.1% (applicable to intermittent periods when steam coils would be used)

3.4 UNIT VARIABLE FREQUENCY DRIVE UPGRADES

Variable-frequency drives (VFDs) function by controlling electric motor speed by converting incoming constant frequency power to variable frequency, using pulse width modulation. VFD upgrades for main plant electric motors provide many co-benefits, the largest one of which is improved part-load efficiency and performance. The benefit is greatest at low load. The more part load and unit cycling that is done, the greater the benefit.

In addition to the reduced auxiliary power consumption, other benefits that are gained from the installation of VFDs on rotating equipment are as follows:

- Reduced noise levels around the equipment.
- Lower in-rush current during startups.
- Decreased wear on existing auxiliary power equipment.

Disadvantages of the installation of VFDs include the high capital cost plus a minimal amount of increased electrical equipment maintenance associated with the VFD system.

Output power signal quality and reliability of VFD equipment has increased significantly in the last 10 to 15 years. Part of this increased reliability comes from the development of technology to allow the VFD equipment to remain in operation if one or multiple insulated-gate bipolar transistor (IGBT) power cells fail by automatically bypassing the bad cell, or cells, until an outage when repairs can be made. Additionally, output power signals meet Institute of Electrical and Electronics Engineers (IEEE) 519 1992 requirements, eliminating the need for harmonic filters.

VFD installation typically requires about 2 months of total pre-outage work, with a 1-week outage (per device) for the final tie-in. To support installation of the VFDs, the following changes are necessary:

- Replacement of existing rotating equipment coupling with resilient elastomeric block shaft couplings to accommodate the shaft misalignment and absorb the high torque loads during rapid load changes. This means the existing equipment must be de-coupled from the motor and then realigned with the new coupling.
- Upgrades to lube oil system as necessary.
- New VFD enclosure foundations.
- New VFD enclosures and heat exchangers.
- Replace the power supply cables from existing switchgear to the new VFD cabinet. Install new cables from the VFD cabinet to the motor.
- For smaller units, the VFD control enclosure and cabinets will also be smaller with reduced pre-outage time requirements.

A high-level assessment of the technical and economic feasibility of VFD modifications that have been seen as beneficial in previous ACE studies were considered as part of this study. With financial benefits confirmed by integrated resource plan (IRP) modeling, specific modifications can then be reviewed in a detailed effort to confirm the performance and financial benefits of VFD modifications.

3.4.1 A.B. Brown Unit 1 Variable Frequency Drive Upgrades

The A.B. Brown Unit 1 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, cooling tower fans, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the ID fans.

3.4.1.1 Boiler Feed Pumps

The A.B. Brown Unit 1 boiler feed pump is a turbine driven feed pump that already provides high efficiency variable speed capability. The installation of a VFD system on the boiler feed pump will therefore not be evaluated further.

3.4.1.2 Circulating Water Pumps

The circulating water system includes two 50 percent capacity vertical turbine circulating water pumps driven by 1,750 horsepower motors. The impellers on the circulating water pumps were replaced with new impellers in 2008. According to the A.B. Brown Unit 1 operating data provided by Vectren, during the period of January 2017 through September of 2018, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicates that the unit operated between 40 percent load and 60 percent load for approximately 52 percent of the time, a significant period where Unit 1 was operating at a relatively significant part load. The operating data also indicate that the unit operated between 60 percent load and 80 percent load for approximately 15 percent of the time and between 80 percent load and 100 percent load for approximately 33 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). These studies have shown that, for the majority of time, it is more advantageous to operate the circulating water pumps and cooling tower fans at full capacity to maintain the lowest temperature circulating water to the condenser with the resulting lowest condenser pressure possible. This operating scenario typically provides a better plant heat rate than lowering the auxiliary power requirements with a resulting increase in condenser back pressure.

As an example, for every 0.1 in. Hg increase in condenser pressure for A.B. Brown Unit 1, the turbine generator output is expected to decrease by about 0.3 to 0.8 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.3 to 0.4 MW, and the condenser pressure is expected to increase by more than 0.2 in. Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months, creating a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-13 summarizes the rated circulating water pump design conditions, as provided in the A.B. Brown Unit 1 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

Table 3-13 Predicted Circulating Water Pump Operating Conditions at Reduced Flows

	RATED OPERATING CONDITIONS	1% REDUCED FLOW OPERATING CONDITIONS	5% REDUCED FLOW OPERATING CONDITIONS
Flow, gpm	65,000	64,350	61,750
Total head, ft	84	82.3	75.8
Pump brake horsepower, hp	1,558	1,512	1,336
Pump speed, rpm	514	509	488

gpm – gallons per minute; ft – feet; hp – horsepower; rpm – revolutions per minute
Note: The above operating data is for one of two (2x50%) circulating water pumps.

This is not strictly true for systems with a high static head, and the savings could be somewhat less when the pump speed differences are fully accounted for. Detailed pump modeling should be conducted to improve the accuracy of these predictions as part of a next-phase effort.

The only scenarios that Black & Veatch has assessed where the installation of VFD systems on circulating water pumps has been beneficial is with once-through circulating water systems that use river or lake water that cools during winter months and there is no concern of freezing. Since the heat rejection system on A.B. Brown Unit 1 involves the use of a cooling tower, the installation of VFD systems on the circulating water pumps does not appear to be cost effective.

Lastly, the costs of adding VFDs to large motors is significant. The estimated costs for adding VFDs to the two Unit 1 circulating water pumps is $2,100,000.

3.4.1.3 Cooling Tower Fans

Cycle heat rejection is via a seven-cell mechanical draft cross-flow cooling tower with seven mechanical draft cooling tower fans. Each cooling tower fan is driven by a 200 hp motor equipped with a VFD system to control both de-icing and to control condenser backpressure. As the cooling tower fans are already equipped with VFDs, the fans will not be investigated further.

3.4.1.4 Large Draft Fans

According to available information and operating data, the A.B. Brown Unit 1 ID fan auxiliary power consumption benefit is estimated to be a total of 3.3 MW for both fans at full load and 4.1 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0473 pounds per cubic foot (lbm/ft^3) at 322° F.

The estimated furnish and erect price for a VFD system for the A.B. Brown Unit 1 ID fans includes the VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

VFD Deployment for ID Fans

Total Installed Capital Cost:	$2,900,000 for both fans
Auxiliary Power Reduction:	Full load: 3.3 MW
	Low Load: 4.1 MW
Heat Rate (efficiency) improvement:	Full Load: 1.4%
	Low Load: 3.0%

Estimated Additional Annual O&M Cost: $2,000 per unit

The A.B. Brown Unit 1 FD fan auxiliary power consumption benefit is estimated to be a total of 0.85 MW for both fans at full load and 0.7 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0726 pounds per cubic foot (lbm/ft^3) at 74° F.

The estimated furnish and erect price for a VFD system for the A.B. Brown Unit 1 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

VFD Deployment for FD Fans

Total Installed Capital Cost:	$2,000,000 for both fans
Auxiliary Power Reduction:	Full load: 0.85 MW
	Part load: 0.7 MW
Heat Rate (efficiency) Improvement:	Full Load: 0.37%
	Low Load: 0.54%

Estimated Additional Annual O&M Cost: $2,000 per unit

3.4.2 A.B. Brown Unit 2 Variable Frequency Drive Upgrades

The A.B. Brown Unit 2 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, cooling tower fans, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the ID fans.

3.4.2.1 Boiler Feed Pumps

The A.B. Brown Unit 2 boiler feed pump is a turbine driven feed pump that already provides high efficiency variable speed capability. The installation of a VFD system on the boiler feed pump will therefore not be evaluated further.

3.4.2.2 Circulating Water Pumps

The circulating water system includes two 50 percent capacity vertical turbine circulating water pumps driven by 1,750 hp motors. The impellers on the circulating water pumps were replaced with new impellers in 2008. According to A.B. Brown Unit 2 operating data provided by Vectren, during the period of January 2017 through September of 2018, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicate that the unit operated between 40 percent load and 60 percent load for approximately 44 percent of the time, a significant period where Unit 2 was operating at a relatively significant part load. The operating data also indicate that the unit operated between 60 percent load and 80 percent load for approximately 19 percent of the time and between 80 percent load and 100 percent load for approximately 37 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser back pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). These studies have shown that, for the majority of time, it is more advantageous to operate the circulating water pumps and cooling tower fans at full capacity to maintain the lowest temperature circulating water to the condenser with the resulting lowest condenser pressure possible. This operating scenario by and large provides a better plant heat rate than lowering the auxiliary power requirements with a resulting increase in condenser back pressure.

As an example, for every 0.1 in. Hg increase in condenser pressure for A.B. Brown Unit 2, the turbine generator output is expected to decrease by about 0.3 to 0.8 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.3 to 0.4 MW, and the condenser pressure is expected to increase by more than 0.2 in. Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months, creating a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-14 summarizes the rated circulating water pump design conditions, as provided in the A.B. Brown Unit 2 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

Table 3-14 Predicted Circulating Water Pump Operating Conditions at Reduced Flows

	RATED OPERATING CONDITIONS	1% REDUCED FLOW OPERATING CONDITIONS	5% REDUCED FLOW OPERATING CONDITIONS
Flow, gpm	65,000	64,350	61,750
Total head, ft	84	82.3	75.8
Pump brake horsepower, hp	1,558	1,512	1,336
Pump speed, rpm	514	509	488
Note: The above operating data is for one of two (2x50%) circulating water pumps.			

This is not strictly true for systems with a high static head, and the savings could be somewhat less when the pump speed differences are fully accounted for. Detailed pump modeling should be conducted to improve the accuracy of these predictions as part of a next-phase effort.

The only scenarios that Black & Veatch has assessed where the installation of VFD systems on circulating water pumps has been beneficial is with once-through circulating water systems that use river or lake water that cools during winter months and there is no concern of freezing. Since the heat rejection system on A.B. Brown Unit 2 involves the use of a cooling tower, the installation of VFD systems on the circulating water pumps does not appear to be cost effective.

Lastly, the costs of adding VFDs to large motors is significant. The estimated costs for adding VFDs to the two Unit 2 circulating water pumps is $2,100,000.

3.4.2.3 Cooling Tower Fans

Cycle heat rejection is via a seven-cell mechanical draft cross-flow cooling tower with seven mechanical draft cooling tower fans. Each cooling tower fan is driven by a 200 hp motor equipped with a VFD system. As the cooling tower fans are already equipped with VFDs, the fans will not be investigated further.

3.4.2.4 Large Draft Fans

According to available information and operating data, the A.B. Brown Unit 2 ID fan auxiliary power consumption benefit is estimated to be a total of 1.7 MW for both fans at full load and 2.3 MW on the basis of the density of the inlet air to the fans of 0.048 lbm/ft^3 at 321° F.

The evaluated impacts of this project are as follows:

VFD Deployment for ID Fans

Total Installed Capital Cost:	$2,900,000 for both fans
Auxiliary Power Reduction:	Full load: 1.7 MW
	Part Load: 2.3 MW
Heat Rate (efficiency) improvement	Full Load: 0.73%
	Low Load: 1.7%

Estimated Additional Annual O&M Cost: $2,000 per unit

The estimated furnish and erect price for a variable frequency drive system for the A.B. Brown Unit 2 ID fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The Brown Unit 2 FD fan auxiliary power consumption benefit is estimated to be a total of 0.3 MW for both fans at full load and 0.45 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0726 pounds per cubic foot (lbm/ft^3) at 74° F.

The estimated furnish and erect price for a VFD system for the Brown Unit 2 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

VFD Deployment for FD Fans

Total Installed Capital Cost:	$2,000,000 for both fans
Auxiliary Power Reduction:	Full load: 0.3 MW
	Part load: 0.45 MW
Heat Rate (efficiency) improvement	Full Load: 0.13%
	Low Load: 0.34%

Estimated Additional Annual O&M Cost: $2,000 per unit

3.4.3 F.B. Culley Unit 2 Variable Frequency Drive Upgrades

The F.B. Culley Unit 2 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the circulating water pumps.

3.4.3.1 Boiler Feed Pumps

F.B. Culley Unit 2 includes one 100 percent capacity motor driven boiler feed pumps. The pump is driven by a 2,500 hp single-speed electric motor, which indicates that this system is amenable to a VFD deployment. The boiler feed pump has a design capacity of 1,980 gpm. Feedwater flow at full load is 1,550 gpm and 960 gpm at low load.

Table 3-15 Boiler Feed Water Pump Operating Conditions

	RATED OPERATING CONDITIONS	FULL LOAD	LOW LOAD	FULL LOAD WITH VFD	LOW LOAD WITH VFD
Flow, gpm	1,980	1,550	960	1,550	960
Total head, ft	3,980	4,375	4,550	3,700	3,307
Pump brake horsepower, hp	2,388	2,146	1,690	1,771	1,133
Pump speed, rpm	3,750	3,750	3,750	3,310	3,050

The evaluated impacts of this project are as follows:

VFD Deployment for Boiler Feed Pump

Total Installed Capital Cost:	$600,000
Auxiliary Power Reduction:	Full load: 0.3 MW
	Part load: 0.4 MW
Heat Rate (efficiency) improvement	0.6%

Estimated Additional Annual O&M Cost: $2,000 per unit

3.4.3.2 Circulating Water Pumps

Unit cooling is provided via a once-through circulating water system utilizing river water as the cooling water supply. Circulating water pump installation is two 50 percent capacity vertical turbine wet pit circulating water pumps. The pumps are driven by 450 hp motors. The circulating water pumps take suction directly from the Ohio River. According to F.B. Culley Unit 2 operating data provided by Vectren, during the period of January 2017 through January of 2019, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicate that the unit operated between 40 percent load and 60 percent load for approximately 45 percent of the time, a significant period where Unit 2 was operating at a relatively significant part load. The operating data also indicate that the unit operated between 60 percent load and 80 percent load for approximately 23 percent of the time and between 80 percent load and 100 percent load for approximately 32 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser back pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser back pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). However, Black & Veatch has assessed some coal fired plants where the installation of VFD systems on circulating water pumps has been beneficial when unit cooling was provided by once-through circulating water systems using river or lake water. The impact is particularly beneficial during winter months when the water supply is cold and there is no concern of freezing.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-16 summarizes the rated circulating water pump design conditions, as provided in the F.B. Culley Unit 2 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

Table 3-16 Predicted Circulating Water Pump Operating Conditions at Reduced Flows

	RATED OPERATING CONDITIONS	1% REDUCED FLOW OPERATING CONDITIONS	5% REDUCED FLOW OPERATING CONDITIONS
Flow, gpm	34,920	33,947	32,576
Total head, ft	43.7	42.8	39.4
Pump brake horsepower, hp	443	430	380
Pump speed, rpm	505	500	480
Note: The above operating data is for one of two (2x50%) circulating water pumps.			

This is not strictly true for systems with a high static head, and the savings could be somewhat less when the pump speed differences are fully accounted for. Detailed pump modeling should be conducted to improve the accuracy of these predictions as part of a next-phase effort.

Variations in pump speed and circulating water flow can have a significant impact on condenser pressure, particularly when the reduced speed and corresponding decrease in flow result in an increased circulating water temperature to the unit. As an example, for every 0.1 in. Hg increase in condenser pressure for F.B. Culley Unit 2, the turbine generator output is expected to decrease by about 0.1 to 0.5 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.09 to 0.1 MW, and the condenser pressure is expected to increase by more than 0.2 in. Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months, creating a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

However, when unit cooling is provided by once-through circulating water systems using river water, such as the F.B. Culley Unit 2, the water supply can be provided with little day-to-day variation in temperature. This is particularly beneficial during the winter months when the water supply is very cold and any reduction in circulating water pump speed, with the corresponding decrease in flow, can have little effect on the condenser pressure.

Evaluating the impact to condenser pressure and auxiliary load by the addition of VFDs to circulating water pumps on units with once-through cooling is an involved assessment. It is necessary to determine a temperature profile of the river water over at least one annual operating period since the cooling water temperature directly impacts condenser back pressure. Additionally, the circulating water flow rate impacts heat transfer, which also directly impacts condenser back pressure. The assessment basically requires creating condenser back pressure curves as a function of the two different variables but must also consider the river water temperature profile as a function of time. The assessment would then identify the auxiliary power savings on the basis of the operating profile of the VFD speed controlled circulating water pumps. Still another concern is that low water flow velocities can cause silting and drop-out of suspended particles in piping.

The costs of adding VFDs to large motors is significant, but in the case of once-through cooling water systems, the investment can prove beneficial. The estimated costs for adding VFDs to the two Unit 2 circulating water pumps is $900,000.

3.4.3.3 Large Draft Fans

Vectren personnel informed Black & Veatch that F.B. Culley Unit 2 has already installed VFDs on the ID fans, which are typically the motors that can gain the most HRI benefit.

The Culley Unit 2 FD fan auxiliary power consumption benefit is estimated to be a total of 0.3 MW for both fans at full load and 0.3 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0727 pounds per cubic foot (lbm/ft^3) at 74° F.

The estimated furnish and erect price for a VFD system for the Culley Unit 2 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

VFD Deployment for FD Fans

Total Installed Capital Cost:	$2,000,000 for both fans
Auxiliary Power Reduction:	Full load: 0.3 MW
	Low load: 0.3 MW
Heat Rate (efficiency) improvement:	Full Load: 0.34%
	Low Load: 0.57%

Estimated Additional Annual O&M Cost: $2,000 per unit

3.4.4 F.B. Culley Unit 3 Variable Frequency Drive Upgrades

The F.B. Culley Unit 3 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the circulating water pumps.

3.4.4.1 Boiler Feed Pumps

The F.B. Culley Unit 3 boiler feed pump is a turbine driven feed pump that already provides high efficiency variable speed capability. The installation of a VFD system on the boiler feed pump will therefore not be evaluated further.

3.4.4.2 Circulating Water Pumps

Unit cooling is provided via a once-through circulating water system utilizing river water as the cooling water supply. The circulating water system includes two 50 percent capacity vertical turbine circulating water pumps driven by electric motors. The circulating water pumps take suction directly from the Ohio River. According to F.B. Culley Unit 3 operating data provided by Vectren, during the period of January 2017 through June of 2018, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicate that the unit operated between 60 percent load and 80 percent load for approximately 14 percent of the time and between 80 percent load and 100 percent load for approximately 60 percent of the time. The operating data also indicate that the unit operated at less than 60 percent load for approximately 26 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser back pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser back pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). However, Black & Veatch has assessed some coal fired plants where the installation of VFD systems on circulating water pumps has been beneficial when unit cooling was provided by once-through circulating water systems using river or lake water. The impact is particularly beneficial during winter months when the water supply is cold and there is no concern of freezing.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-17 summarizes the rated circulating water pump design conditions, as provided in the Culley Unit 3 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

Table 3-17 Predicted Circulating Water Pump Operating Conditions at Reduced Flows

	RATED OPERATING CONDITIONS	1% REDUCED FLOW OPERATING CONDITIONS	5% REDUCED FLOW OPERATING CONDITIONS
Flow, gpm	69,000	68,310	65,550
Total head, ft	57	55.9	51.4
Pump brake horsepower, hp	1170	1135	1,003
Pump speed, rpm	300	297	285
Note: The above operating data is for one of two (2x50%) circulating water pumps.			

Variations in pump speed and circulating water flow can have a significant impact on condenser pressure, particularly when the reduced speed and corresponding decrease in flow result in an increased circulating water temperature to the unit. As an example, for every 0.1 in. Hg increase in condenser pressure for F.B. Culley Unit 3, the turbine generator output is expected to decrease by about 0.4 to 0.9 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.25 MW, and the condenser pressure is expected to increase by more than 0.2 in Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months. This creates a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

However, when unit cooling is provided by once-through circulating water systems using river water, such as the F.B. Culley Unit 3, the water supply can be provided with little day-to-day variation in temperature. This is particularly beneficial during the winter months when the water supply is very cold and any reduction in circulating water pump speed, with the corresponding decrease in flow, can have little effect on the condenser pressure.

Evaluating the impact to condenser pressure and auxiliary load by the addition of VFDs to circulating water pumps on units with once-through cooling is an involved assessment. It is necessary to determine a temperature profile of the river water over at least one annual operating period since the cooling water temperature directly impacts condenser back pressure. Additionally, the circulating water flow rate impacts heat transfer, which also directly impacts condenser back pressure. The assessment basically requires creating condenser back pressure curves as a function of the two different variables but must also consider the river water temperature profile as a function time. The assessment would then identify the auxiliary power savings on the basis of the operating profile of the VFD speed controlled circulating water pumps. Moreover, plant personnel have expressed concerns about silting problems due to low water velocity, which is already a known issue at the plant, where, extended periods of operation at low flows have led to silting in the condenser tubes and associated corrosion.

The costs of adding VFDs to large motors is significant, but in the case of once-through cooling water systems, the investment can prove beneficial. The estimated costs for adding VFDs to the two Unit 3 circulating water pumps is $2,100,000.

3.4.4.3 Large Draft Fans

Vectren personnel informed Black & Veatch that F.B. Culley Unit 3 has already installed VFDs on the ID fans, which are typically the motors that can gain the most HRI benefit at a coal fired power plant.

The only other large rotating equipment identified for this F.B. Culley Unit 3 study that has the potential for significant HRI benefits from a VFD retrofit are the FD fans. The F.B. Culley Unit 3 FD fan auxiliary power consumption benefit is estimated to be a total of 0.6 MW for both fans at full load and 0.9 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0727 pounds per cubic foot (lbm/ft^3) at 74° F.

The estimated furnish and erect price for a VFD system for the Culley Unit 3 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

VFD Deployment for FD Fans

Total Installed Capital Cost:	$2,000,000 for both fans
Auxiliary Power Reduction:	Full load: 0.6 MW
	Low load: 0.9 MW
Heat Rate (efficiency) improvement:	Full load: 0.23%
	Low Load: 0.69%

Estimated Additional Annual O&M Cost: $2,000 per unit

3.5 BOILER FEED PUMP UPGRADES, REBUILDING, OR REPLACEMENT

The purpose of this project would be to reduce the energy consumed by the boiler feed pumps by exploring whether upgrades or repairs to the pump internal components, or replacement in kind with a new boiler feed pump would be warranted. As steam-driven boiler feed pumps are inherently much more efficient than any electric-driven boiler feed pumps, no analysis of a conversion to VFD use will be assessed on A.B. Brown Units 1 and 2, or Culley Unit 3.

3.5.1 A.B. Brown Unit 1 Boiler Feed Pumps

A.B. Brown 1 has one Pacific, 5 stage, Type BFIDS, Size 12" RHBK pump. The pump has a rated capacity of 4,400 gpm at 5,470 feet of head, 5,400 rpm, for 367 °F water. With the current data available, there is no indication that any significant improvement could be made to the overall unit heat rate by upgrading this pump. Discussions with one boiler feed pump retrofit vendor indicated that at best a 1-1.5% drive turbine efficiency could be realized, which would only translate to a very small efficiency improvement on a unit basis.

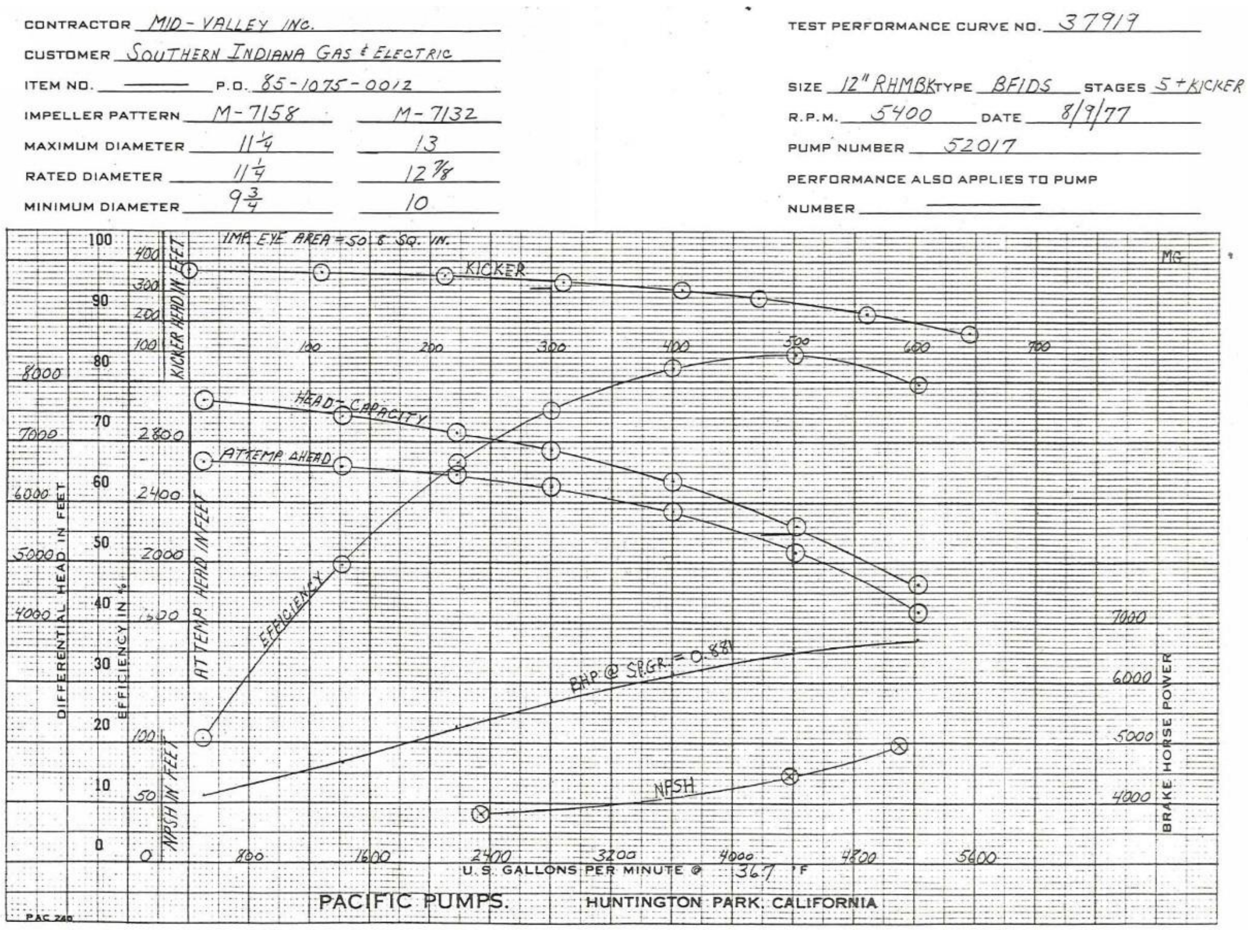


Figure 3-9 Brown 1, Brown 2, and Culley 3 Boiler Feed Pump Performance Curve

3.5.2 A.B. Brown Unit 2 Boiler Feed Pumps

A.B. Brown 2 has one Pacific, 5 stage, Type BFIDS, Size 12" RHBK pump. The pump has a rated capacity of 4,400 gpm at 5,470 feet of head, 5,400 rpm, for 367 °F water. As in the case of Unit 1, with the current data available, there is no indication that any significant improvement could be made to the overall unit heat rate by upgrading this pump. Discussions with one boiler feed pump retrofit vendor indicated that at best a 1-1.5% drive turbine efficiency could be realized, which would only translate to a very small efficiency improvement on a unit basis.

3.5.3 F.B. Culley Unit 2 Boiler Feed Pumps

F.B. Culley 2 has one Byron Jackson, double volute, 7 stage multiplex, Type DVMX, Size 6x8x11B pump. The pump has a rated capacity of 1,980 gpm at 3,980 feet of head, 3,750 rpm, and 220 °F water. The full load operating data set Black & Veatch was provided has the BFP operating with a discharge flow rate of 1,550 gpm and a total developed head of 3,980 ft. The pump curve shows that the pump should have a TDH of 4,380 ft. The actual developed head of the BFP is 9.2% less than that of the design curve. The pump no longer lies on the initial operating curve which suggest that degradation has occurred. Please see the section on VFD deployment for further information on upgrades that are possible for F.B. Culley Unit 2's boiler feed pump.

3.5.4 F.B. Culley Unit 3 Boiler Feed Pumps

F.B. Culley 3 has one Pacific, 5 stage, Type BFIDS, Size 12" RHBK pump. The pump has a rated capacity of 4,400 gpm at 5,470 feet of head, 5,400 rpm, for 367 °F water. With the current data available, there is no indication that any significant improvement could be made to the overall unit heat rate by upgrading this pump. Discussions with one boiler feed pump retrofit vendor indicated that at best a 1-1.5% drive turbine efficiency could be realized, which would only translate to a very small efficiency improvement on a unit basis.

3.6 UNIT NEURAL NETWORK DEPLOYMENT

The purpose of this project would be to tune the system to allow for the reduction of boiler outlet oxygen concentration without increasing NO_X or carbon monoxide (CO) emissions. Adaptive neural net systems have the greatest effect when controlling air flow and fuel mixtures down to a fine level. The full benefits are realized only if the plant has adequate feedback signals to allow the neural net to sense changes made to the available controls. For instance, individual fuel and air controls at each burner provide tremendous levers for a neural net system; however, the effect of the levers is reduced if the neural net does not receive feedback about the air/fuel mixture through a grid of CO measurements.

3.6.1 A.B. Brown Unit 1 Neural Network Deployment

The unit has the ability to bias individual mills as well as compartmented windboxes. Each burner row has an independent windbox with a damper for air control on each end, but there is only manual secondary air adjustment at each individual burner. CO measurement is located at the outlet of the reheat section, but this requires regular maintenance for reliable operation.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance. Still another benefit would be the ability to better control the balance of O_2 across the furnace, which is known to be a current concern.

For A.B. Brown Unit 1, the excess oxygen varies roughly from between 2 percent to 4.5 percent at gross output levels above 250 MW, with an average level approximating 3.0 to 3.3 percent. No online correlation of NPHR or boiler efficiency from distributed control system (DCS) system calculations was readily available from which to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate:

- 0.25 percent reduction in excess O_2: 0.10 percent gain in boiler efficiency, 0.23 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess O_2: 0.21 percent gain in boiler efficiency, 0.43 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess O_2: 0.27 percent gain in boiler efficiency, 0.60 percent improvement in net plant heat rate.

Utilization of a specific Vista model of A.B. Brown Unit 1 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it would be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by approximately 0.25 percent, then the NPHR improvement would be about 0.23 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess O_2 levels.

Total Installed Capital Cost:	$500,000
Heat Rate (efficiency) Improvement:	0.23%

3.6.2 A.B. Brown Unit 2 Neural Network Deployment

The unit has the ability to bias individual mills as well as compartmented windboxes. Each burner row has an independent windbox with a damper for air control on each end, but there is only manual secondary air adjustment at each individual burner. There is no valid CO measurement [4]; thus, the unit must be restricted to an arbitrary O_2 lower limit to avoid typical low oxygen combustion issues such as slagging and tube wastage.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels

[4] Lack of a valid CO measurement would significantly hamper the ability of a neural network system to affect positive change in unit operations.

improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance.

For A.B. Brown Unit 2, the excess oxygen varies roughly from between 2 percent to 4.5 percent at gross output levels above 250 MW, with an average level approximating 3.1 to 3.3 percent. No online correlation of NPHR or boiler efficiency from DCS system calculations was readily available from which to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate (these are the same as A.B. Brown Unit 1):

- 0.25 percent reduction in excess O_2: 0.10 percent gain in boiler efficiency, 0.23 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess O_2: 0.21 percent gain in boiler efficiency, 0.43 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess O_2: 0.27 percent gain in boiler efficiency, 0.60 percent improvement in net plant heat rate.

Utilization of a specific Vista model of Brown 2 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it could be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by approximately 0.25 percent then the NPHR improvement would be about 0.23 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess O_2 levels.

Total Installed Capital Cost:	$500,000
Heat Rate (efficiency) Improvement:	0.23%

3.6.3 F.B. Culley Unit 2 Neural Network Deployment

The unit has the ability to bias individual mills, and each burner has an air shroud that can be biased; fuel biasing is available at each burner. Also, there is no valid CO measurement; thus, the unit must be restricted to an arbitrary O_2 lower limit to avoid typical low oxygen combustion issues such as slagging and tube wastage.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance.

The excess oxygen varies roughly from between 3.5 percent to 5.2 percent at gross output levels above 80 MW, with an average level approximating 4.3 percent. No online correlation of

NPHR or boiler efficiency from DCS system calculations was readily available from which to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate:

- 0.25 percent reduction in excess O_2: 0.15 percent gain in boiler efficiency, 0.26 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess O_2: 0.29 percent gain in boiler efficiency, 0.47 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess O_2: 0.43 percent gain in boiler efficiency, 0.62 percent improvement in net plant heat rate.

Utilization of a specific Vista model of F.B. Culley 2 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it could be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by approximately 0.25 percent, then the NPHR improvement would be approximately 0.26 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess O_2 levels.

Total Installed Capital Cost:	$500,000
Heat Rate (efficiency) Improvement:	0.26%

3.6.4 F.B. Culley Unit 3 Neural Network Deployment

The unit has the ability to bias individual mills, and each burner has an air shroud that can be biased; there is no fuel biasing available at each burner. Also, there is no valid CO measurement[5]; thus, the unit must be restricted to an arbitrary O_2 lower limit to avoid typical low oxygen combustion issues such as slagging and tube wastage.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance. Plant personnel have commented that this could also help to control the O_2 balance across the furnace, which would yield better combustion control and help reduce slagging.

For F.B. Culley Unit 3, the excess oxygen varies roughly from between 2.5 percent to 4.2 percent at gross output levels above 270 MW, with an average level approximating 3.5 percent. No online correlation of net plant heat rate NPHR or boiler efficiency from DCS system calculations was

[5] Lack of a valid CO measurement would significantly hamper the ability of a neural network system to affect positive change in unit operations.

readily available to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate:

- 0.25 percent reduction in excess O_2: 0.13 percent gain in boiler efficiency, 0.25 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess O_2: 0.24 percent gain in boiler efficiency, 0.46 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess O_2: 0.32 percent gain in boiler efficiency, 0.62 percent improvement in net plant heat rate.

Utilization of a specific Vista model of F.B. Culley 3 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it could be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by about 0.25 percent, then the NPHR improvement would be about 0.25 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess O_2 levels.

Total Installed Capital Cost:	$500,000
Heat Rate (efficiency) Improvement:	0.25%

3.7 UNIT INTELLIGENT SOOTBLOWING DEPLOYMENT

The purpose of this project would be to reduce the required sootblowing flow by installing an integrated intelligent sootblowing (ISB) control system. This system would utilize heat flux sensors, hanger strain gauges, and process data to determine the areas needing to be cleaned. By cleaning only “dirty” areas, sootblowing flow would be reduced and tube life potentially extended.

3.7.1 A.B. Brown Unit 1 Intelligent Sootblowing Deployment

An ISB system will not be investigated for this unit because A.B. Brown Unit 1 already has ISB installed.

3.7.2 A.B. Brown Unit 2 Intelligent Sootblowing Deployment

An ISB system will not be investigated for this unit because A.B. Brown Unit 2 already has ISB installed.

3.7.3 F.B. Culley Unit 2 Intelligent Sootblowing Deployment

The plant uses air as the sootblowing media, but currently, no heat flux sensors or hanger strain gauges are installed. Sootblowing is currently based on operator observation, attemperation, and control operator judgement. In addition to current sootblower O&M, it is estimated that an ISB could reduce sootblowing by approximately 10 percent or greater.

Total Installed Capital Cost:	$350,000
Heat Rate (efficiency) Improvement:	0.10%

3.7.4 F.B. Culley Unit 3 Intelligent Sootblowing Deployment

An ISB system will not be investigated for this unit because F.B. Culley Unit 3 already has ISB installed.

3.8 IMPROVED O&M PRACTICES

The purpose of this project would be to improve O&M practices as they pertain to three particular areas of focus: heat rate improvement training, on-site appraisals for identifying additional heat rate improvements, and improved condenser cleaning strategies.

3.8.1 Heat Rate Improvement Training

Black & Veatch conducts heat rate awareness training, which covers the fundamentals of determining unit performance, how to use these metrics, and the operating conditions and decisions that impact unit efficiency and heat rate. The course includes numerous real-life case studies identified through years of monitoring and diagnostic work. This on-site course is typically 2.5 days and is primarily geared toward operators and engineers.

Total Installed Capital Cost	$15,000/class (could cover multiple units and plants)
Heat Rate (efficiency) Improvement:	Unknown, although improved O&M practices at peer coal fired EGUs have claimed to result in net plant heat rate improvements of 0.1 to 0.5 percent in the first year of implementation

3.8.2 On-Site Heat Rate Appraisals

On-site heat rate appraisals, mentioned as a BSER in the EPA ACE proposal, is left open to interpretation; indeed, the EPA was not able to provide suitable guidance for estimated ranges of capital cost or HRI. On-site heat rate appraisals are often conducted via a detailed assessment of controllable losses, especially those that can be reduced or eliminated by low-impact operations changes and equipment repairs and upgrades. This assessment utilizes a combination of a review and analysis of historical operations data, interviews with plant O&M personnel, review of past test and capability reports, a detailed study of the current fuel sources and fuel-related impacts upon the plant, discussions with plant management to understand the plant generation goals and objectives, and a reliability and maintenance history analysis.

Real-world examples of heat rate improvement projects resulting from on-site heat rate appraisals and audits include the following:

- Diagnosis of a cracked feedwater heater partition plate via analysis of online performance data, which resulted in a $12,000 monthly heat rate savings and 0.4 MW capacity improvement.
- Discovery of a failed reheat stop valve by analyzing reheat pressure swings over time, resulting in a $65,000 monthly heat rate improvement and 4 MW capacity improvement.
- An audit of terminal temperature difference (TTD) and drain cooler approach (DCA) temperature trends across a feedwater heater train at one power plant found that the highest-pressure feedwater heater emergency drain valve was leaking, with 50 percent of its flow returning to the condenser, rather than cascading to the next feedwater heater. This failure resulted in a heat rate loss of 53 Btu/kWh (about 0.5 percent and a net capacity loss of 2.5 MW.
- Testing of mill dirty air flows and coal flow balances at one power plant found that by rebalancing the flows on four mills to bring the coal and air flow deviation to within ± 10% (compared to the ± 30 percent it formerly operated at), coal unburned carbon heat losses decreased by 0.5 percent, which directly translated to an HRI of 0.5 percent. Moreover, burner-zone slagging was nearly eliminated by this change, resulting in significantly less use of sootblowing steam in the furnace wall blowers, which resulted in an additional long-term heat rate benefit of 0.1 percent (and a corresponding improvement in furnace wall tube life).
- Long-term analysis of subtle deviations in feedwater heater extraction lines revealed an internal line had failed, resulting in not only a $15,000 heat rate loss, but the potential for an unplanned outage because of debris in the heater.
- An analysis of 19 different truck coals supplied to a power plant found that not only were 7 of the coals unprofitable to burn, burning the worst coal resulted in a heat rate loss of more than 2 percent Moreover, this coal was responsible, in whole or in part, for the majority of the plant de-rates because of high-temperature sodium-based fouling, which cost the unit an additional 1.2 percent in heat rate on an annual basis because of the increased number of starts and stops from fouling-related outages.
- A long-term analysis of plant continuous emissions monitoring system (CEMS) data and motor amperage data found that a malfunctioning VFD controller in the coal handling system was responsible for incorrect blending of two different coals to meet the plant SO_2 limit, resulting in not only excess use of low-sulfur coal, but a loss of heat rate equating 0.6 percent on an annual basis.

Heat rate assessment is an ever-moving target, so while there is substantial benefit from a focused heat rate auditing and improvement program, long-term use of some type of performance and O&M monitoring system will provide the best overall heat rate improvement.

3.8.3 Improved Condenser Cleanliness Strategies

3.8.3.1 A.B. Brown Unit 1 Improved Condenser Cleaning Strategies

Condenser performance problems can be caused by any combination of many factors: tube sheet fouling, tube fouling, high number of plugged tubes, circulating water flow issues, waterbox priming, air in-leakage, and poor steam cycle isolation to condenser. Generally, plant data can provide clear evidence of condenser performance problems, but the causes may be difficult to discern.

To determine condenser performance, an energy balance was calculated between the boiler and turbine cycle. Gross generation data allowed the calculation of a gross turbine cycle heat rate and condenser heat duty. The condenser design data and industry standard condenser performance calculations were used to determine the actual operating condenser performance and calculate the expected back pressure. This allowed a comparison between actual and expected condenser back pressure. The turbine OEM back pressure correction curve was employed to calculate a heat rate impact for the difference between actual and expected back pressure. For every hour of operation in the remaining data set, the heat rate impact in $/hour was calculated with an assumed fuel cost of $2.50/MBtu, actual generation, and assumed boiler efficiency.

Condenser performance was reviewed over 1.3 years of operating data. The timing covered two summers and one winter. Condenser performance was calculated across load and across seasons. The working data set began with 8,500 hours of data. Nearly 8,000 hours of data (93 percent) were considered good quality and used for analysis. The range of unit load for the data set spanned 120 MW to 270 MW gross load. Low load operation (less than 175 MW gross) comprised 56 percent of the generation while high loads (less than 240 MW gross) accounted for 31 percent operating data.

From summer 2017 to summer 2018, the hourly average heat rate impact for condenser back pressure showed a significant change across the 2018 spring outage. Condenser performance during 2017 showed very poor performance at low loads. The expected back pressure across load for A.B. Brown Unit 1 is shown by the red trace on Figure 3-10. Actual unit back pressure is shown by the blue trace on this figure. Actual back pressure never falls below 3.3 in. HgA when the unit drops load. This yielded a high heat rate impact on average of 84 Btu/kWh, with an associated fuel cost of $37.00/h.

Figure 3-10 shows a “floor” in actual back pressure (blue) around 3.5 in. HgA in 2017. As unit load goes down, the back pressure should follow the red trend.

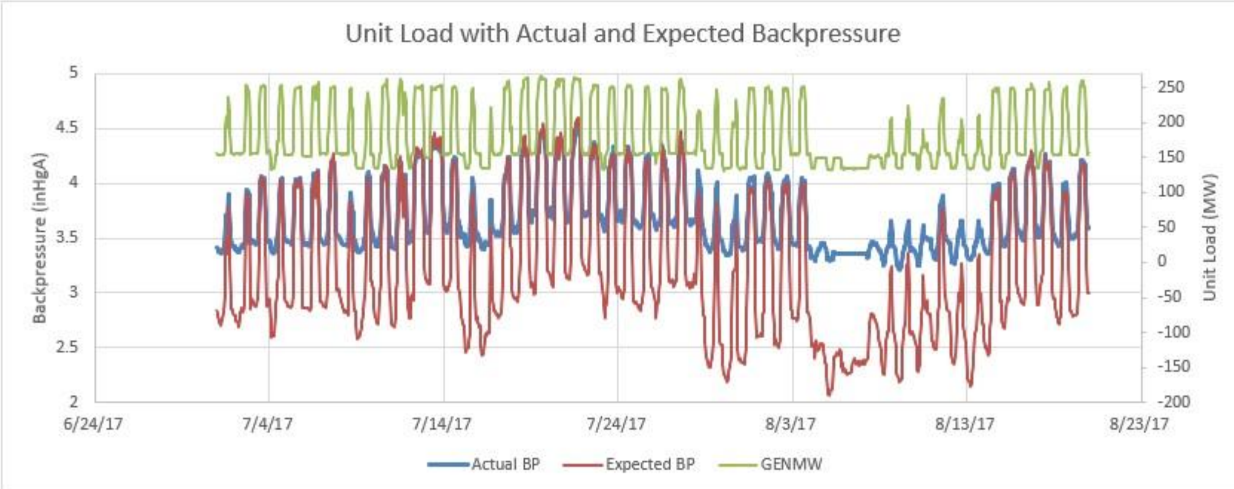


Figure 3-10 **Summer 2017 Backpressure vs Time (the actual is shown in red and blue is expected performance.)**

Figure 3-11 provides the perspective of actual and expected backpressure versus circulating water flow at low load. Back pressure deviations at low load for any unit can be significant.

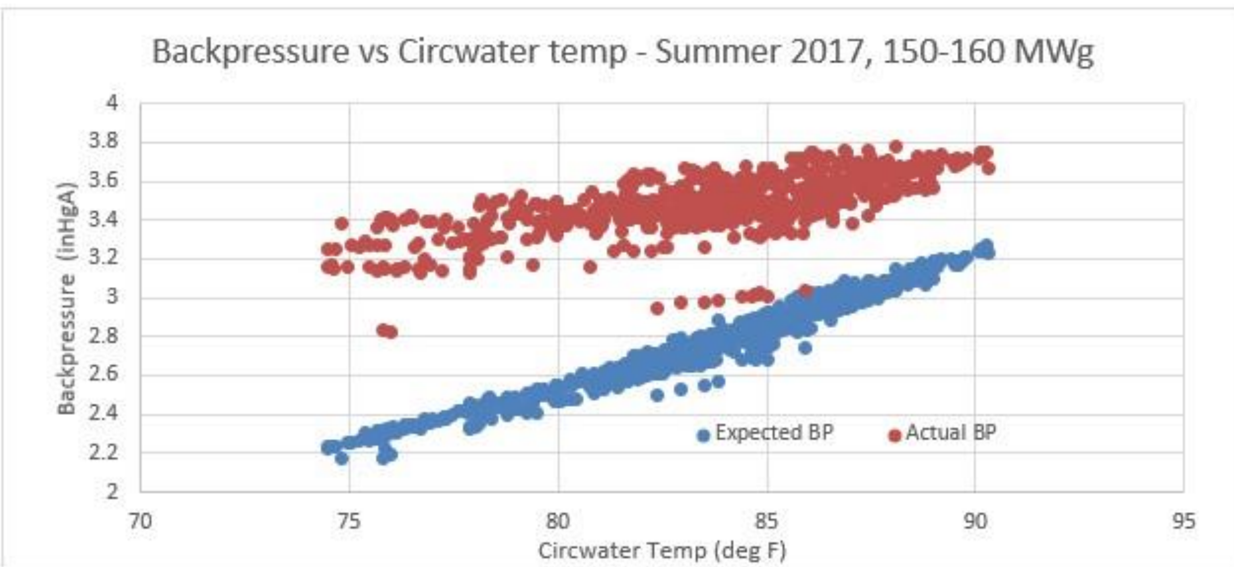


Figure 3-11 **Poor Condenser Performance at Low Load 2017**

When normal operation resumed in May of 2018, condenser performance looked good across load. The average heat rate impact from May to September of 2018 was estimated at 14 Btu/kWh, with a fuel-based heat rate cost of $5.7/h.

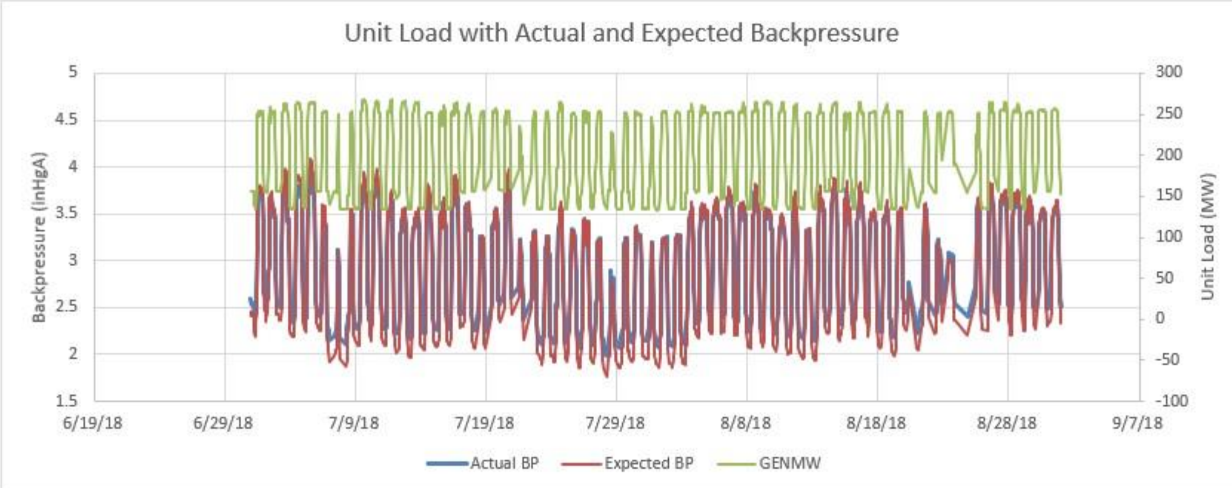


Figure 3-12 2018 Post Outage Actual and Expected Backpressure Over Time

On Figure 3-13 and 3-14, this actual back pressure is much closer to expected values in 2018. The remaining heat rate impact after the outage is likely to be due to the remaining gap in condenser performance at low load.

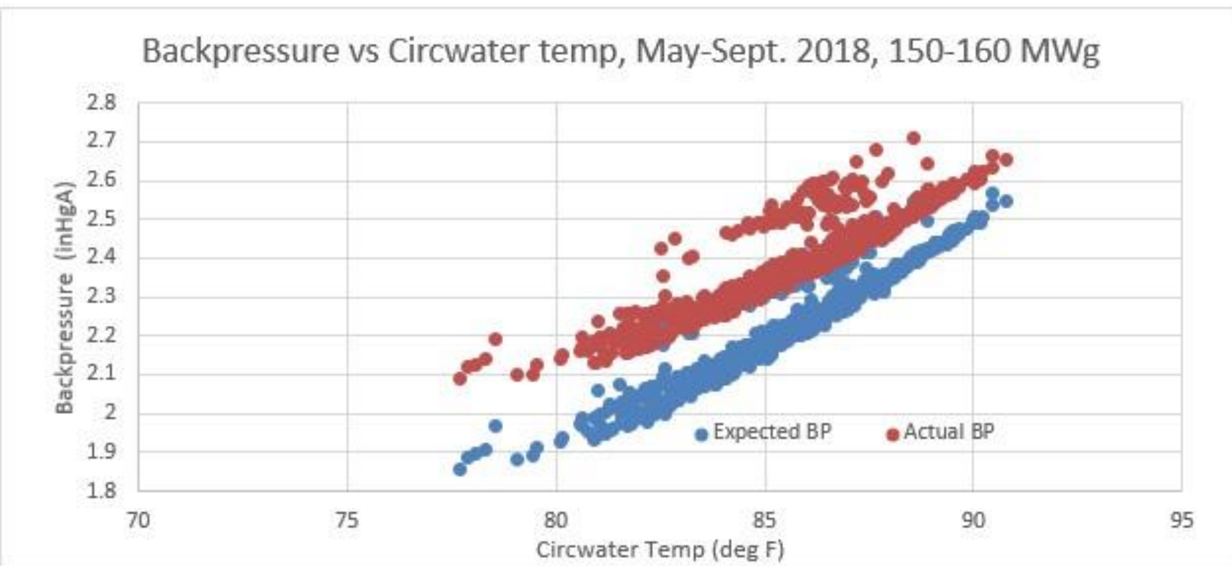


Figure 3-13 2018 Post Outage Performance at Low Load vs Circulating Water Outlet Temperature

Another noted change in condenser operation looking at both summers was calculated circulating water flow rate. Through the summer of 2017, average circulating water flow estimates were typically more than 25 percent below the design circulating water flow rate of 124,000 gpm. After the 2018 spring outage, estimated circulating water flow at full unit load was consistently 145,000 gpm, which is well above design. The estimated flow is sensitive to field measured circulating water temperatures and may need closer inspection.

The combination of these changes suggests significant air in-leakage or air removal improvements were made on the steam side, and water condenser cleaning yielded higher circulating water flows. According to plant personnel, they have repaired steam seal piping internal to the condenser neck. This issue has been appearing more regularly, and F.B. Culley 3 has had to perform similar repairs twice in the last two years. Across the span of the 15 months of operating data at full load, condenser performance was generally good, with cleanliness values at or above 70 percent as shown on Figure 3-14. However, because of low load performance problems, a fuel-based cost for 2017 operation is estimated to be $230,000 on an annual basis. Following the spring 2018 outage, the small deviation from expected condenser performance yields an estimated annual fuel cost of $35,000 on an annual basis. On the basis of the outage improvements seen in 2018, regularly scheduled maintenance and trending of performance should be sufficient to maintain good condenser performance.

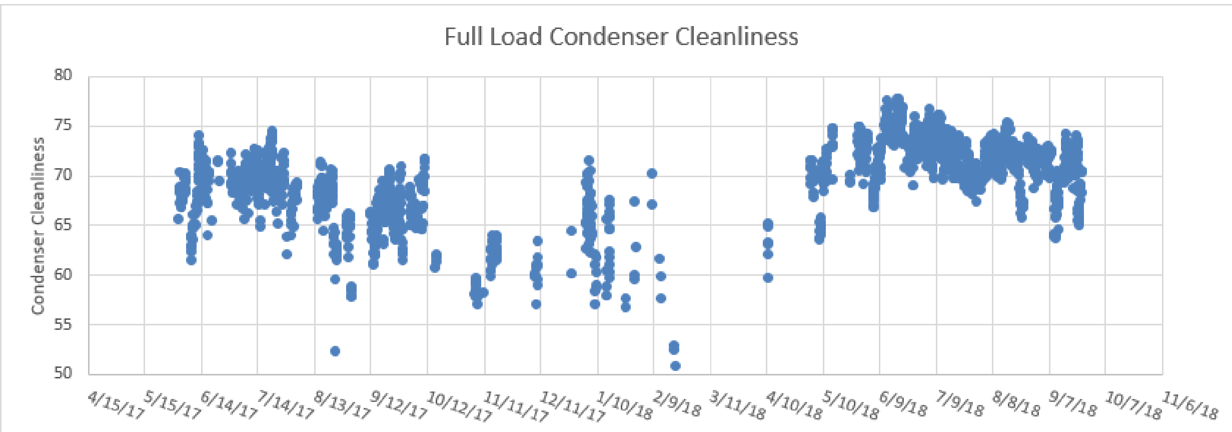


Figure 3-14 Full Load Cleanliness Results Over Time

3.8.3.2 A.B. Brown Unit 2 Improved Condenser Cleaning Strategies

Condenser performance was reviewed over 1.3 years of operating data. The timing covered two summers and one winter. Condenser performance was calculated across load and across seasons. In the process of reducing bad or suspicious data, 46 percent of the total data was removed. Nearly 6,000 hours of operating data ranging from 148 MW gross to full load was used for analysis.

Calculated results showed good performance for the condenser across load. It is suspected that measured back pressure readings may be biased low by approximately 0.2 to 0.3 in. HgA as actual back pressure consistently trended lower than expected and TTD at full load is unrealistically low (too good) at 3.5 to 5° F. The relationship between actual and expected back pressure versus circulating water temperature at constant load can be seen on Figure 3-15. As a result, condenser cleanliness values at full load consistently run greater than 90 percent and more than 100 percent at lower loads. Calculated circulating water flow rate is stable with estimated flows between

110,000 and 120,000 gpm. This is slightly below the design value of 124,000 gpm. Temperature rise across the condenser at full load runs 22° F versus design values of 20° F.

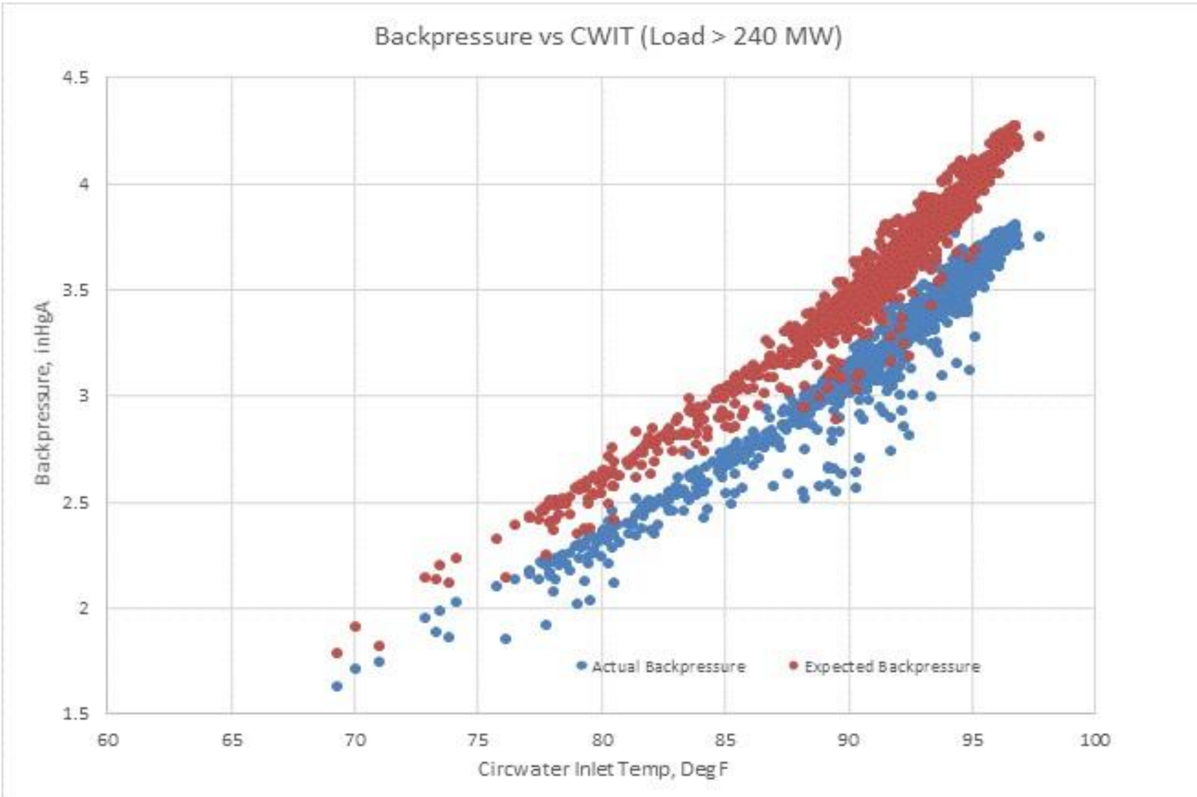


Figure 3-15 Condenser Back Pressure Versus Circulating Water Temperature at High Load

Generally, back pressure trended well across load during summer of 2017 and 2018. Separate trends of condenser performance behavior for summer 2017 and summer 2018 are provided on Figure 3-16 and Figure 3-17.

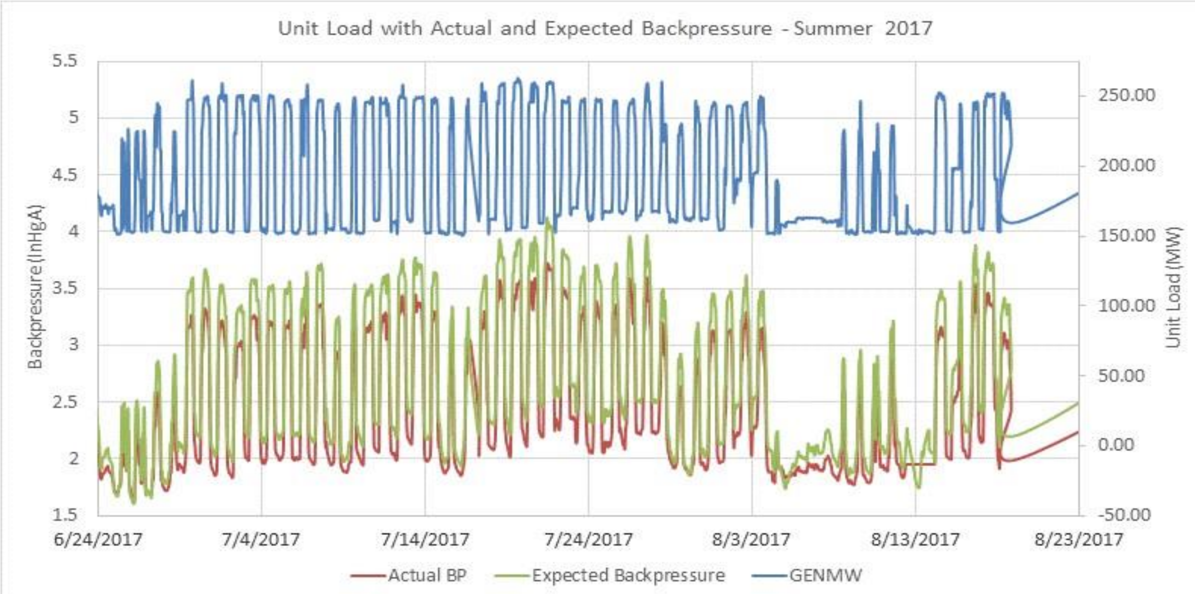


Figure 3-16 Condenser Performance Summer 2017 Across Load

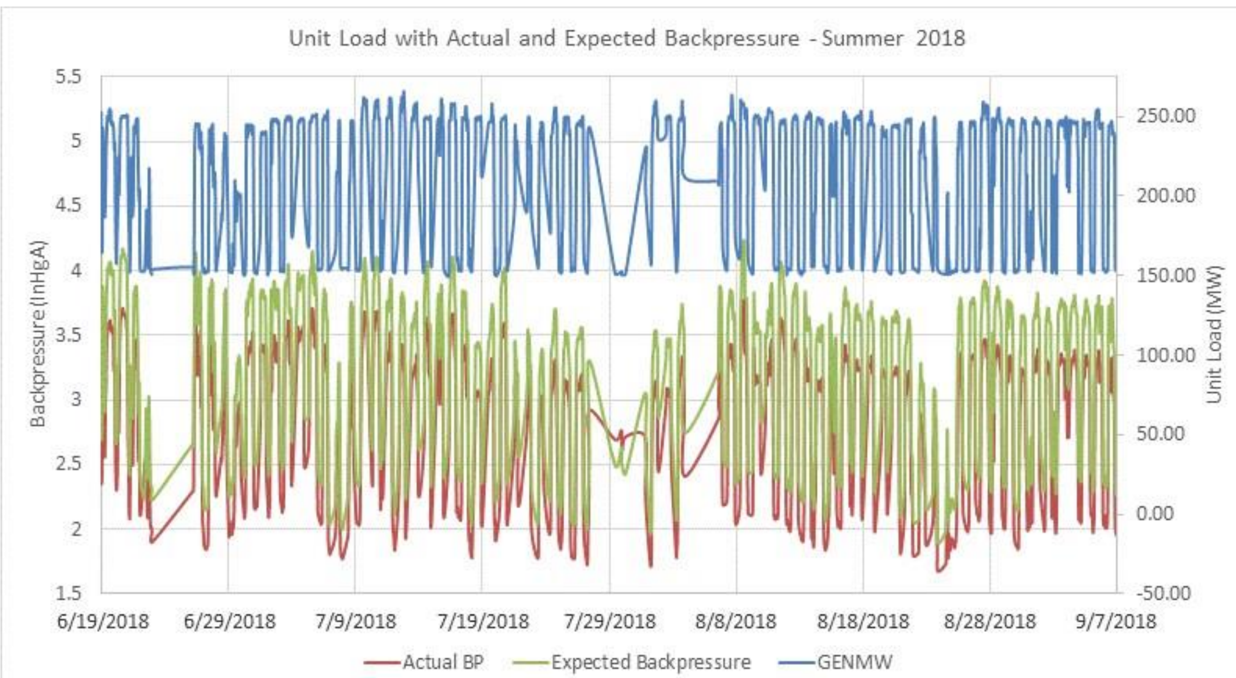


Figure 3-17 Condenser Performance Summer 2018 Across Load

Because the actual back pressure trends better than expected, no heat rate penalty is associated with normal unit operation for the data reviewed. Regularly scheduled maintenance and tracking of performance to highlight changes should be enough to maintain good condenser performance. For improved fidelity and confidence in performance metrics, the measured back pressure indication should be checked for accuracy and proper installation. The addition of more circulating water temperature measurements leaving the condenser would also improve accuracy of results by better capturing temperature stratification in the return piping.

3.8.3.3 F.B. Culley Unit 2 Improved Condenser Cleaning Strategies

For this study, 2 years of plant data were reviewed. Condenser performance was calculated across load and across seasons. Significant data reduction was necessary to eliminate offline or suspect data. This yielded more than 4,800 hours of operating data to characterize operation. In this data set, nearly 60 percent of the operating data were part load operation below 70 MW gross. Just over 30 percent of the data represented loads greater than 90 MW gross.

The hourly average heat rate impact of high condenser back pressure for Unit 2 is $42/h. Assuming the unit operates for 70 percent of a calendar year, this equates to a fuel cost of $257,000 per year. The average cleanliness value for Unit 2 is 28 percent. The highest achieved cleanliness values were in the low 50 percent range. The most significant observation with this analysis is shown on Figure 3-18 and is typical for the unit operation. Back pressure should have a strong load dependency. The Unit 2 back pressure data does not follow the expected pattern. The most likely cause of this behavior is significant air in-leakage or inadequate air removal system performance or limited capacity. Two additional factors are that Unit 2 relies upon steam jet air ejectors for air removal, and there is a suspected large air in-leakage around the turbine that has been present for years and has never been successfully resolved.

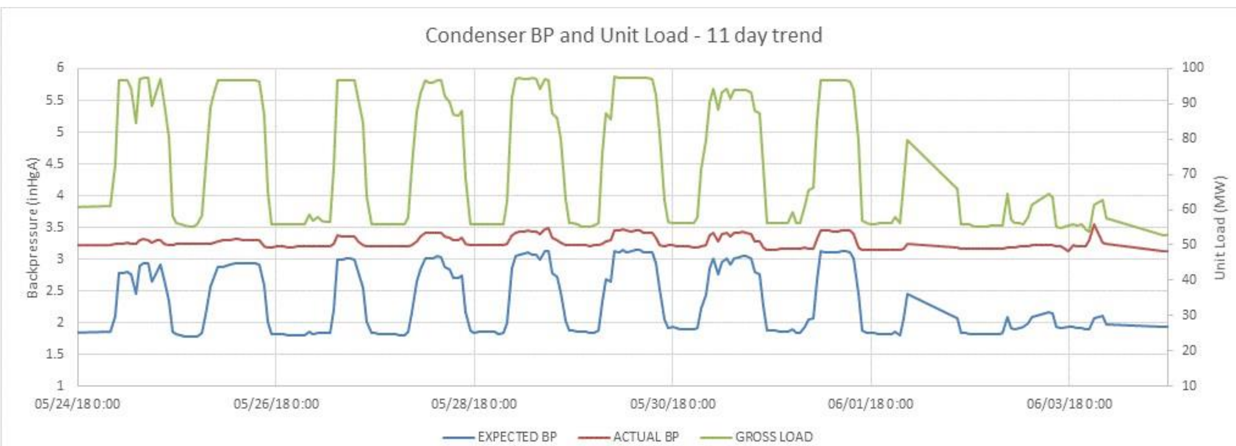


Figure 3-18 Condenser Back Pressure Versus Time (11 Day Trend)

The expected back pressure is calculated assuming no condenser tubes are plugged and cleanliness of 70 percent. Circulating water flow rate is calculated based on actual heat duty and circulating water temperature rise. Looking at full load operations across all season, there is a notable gap between actual and expected back pressure. This is shown on Figure 3-19, which illustrates back pressure versus circulating water temperature and versus time in Figure 3-20. The primary driver is expected to be the same issue of steam side air binding inhibiting lower backpressure at low circulating water temperatures.

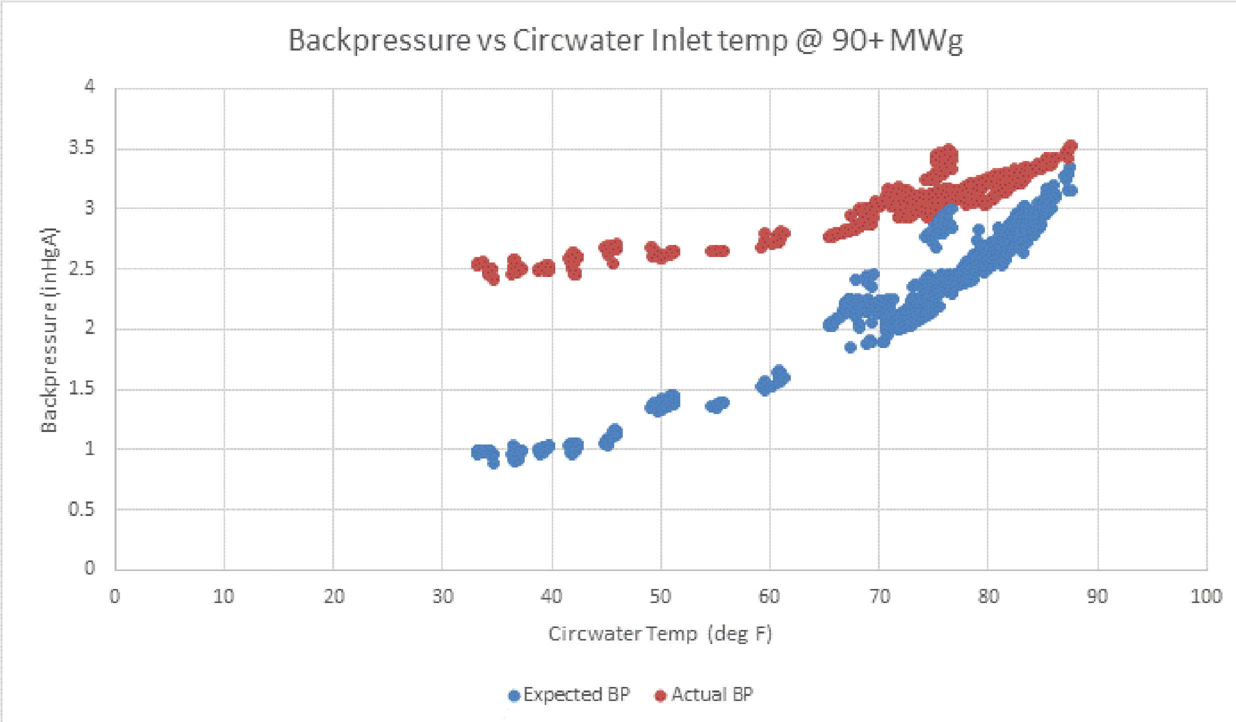


Figure 3-19 Condenser Back Pressure Versus Circulating Water Temperature

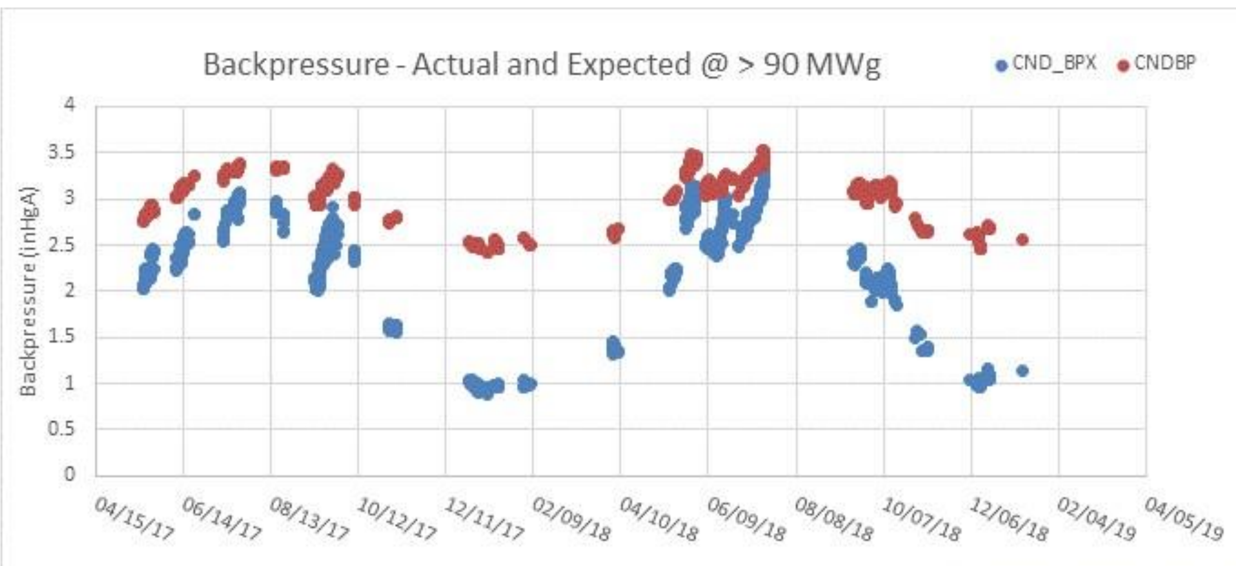


Figure 3-20 Back Pressure Versus Time (2-year trends)

3.8.3.4 F.B. Culley Unit 3 Improved Condenser Cleaning Strategies

The review of operating data for Unit 3 included 1.8 years of operational data. Data reduction to eliminate offline or suspect data eliminated 20 percent of the data, yielding more than 12,700 hours of data. The load used for analysis ranged from 135 MW gross up to 289 MW gross.

The hourly average heat rate impact of high condenser back pressure across all loads was 42 Btu/kWh and $24.8/h. Based on the data set for this analysis, the unit was in operation 90 percent of the time. Assuming this level of availability on an annual basis, the fuel cost associated with poor condenser performance is conservatively estimated at $196,000 per year. Load derates caused by high back pressure limits are probable for this unit, but highly variable, depending on the turbine design and manufacturer recommendation. Given the emphasis on efficiency opportunity in this report, an estimate for potential load impacts is not considered in this evaluation.

The highest sustained cleanliness value was slightly above 60 percent, with significant decay in performance lasting 9 of the 22 months, as seen on Figure 3-21.

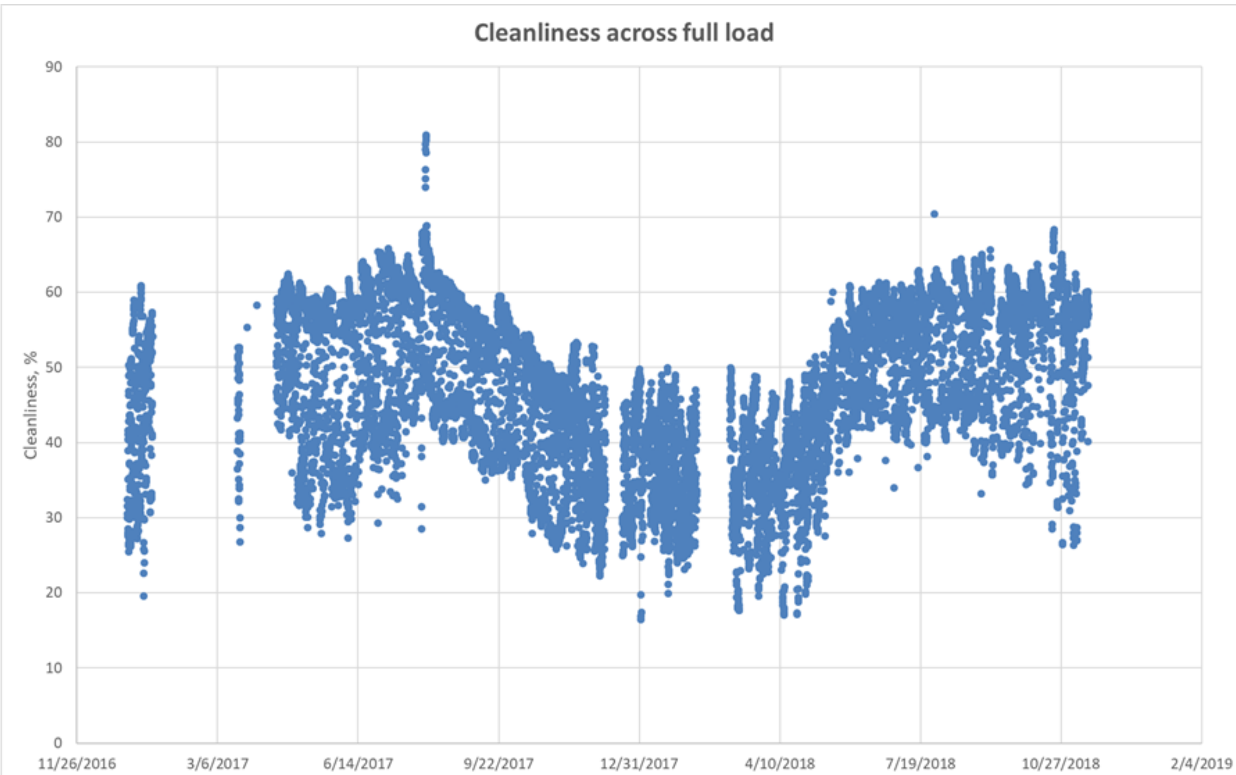


Figure 3-21 Condenser Cleanliness Across Time and Load

On closer look at the operating data, the repeated trend of increasing back pressure suggests significant tube sheet and or tube fouling issues on Figure 3-22.

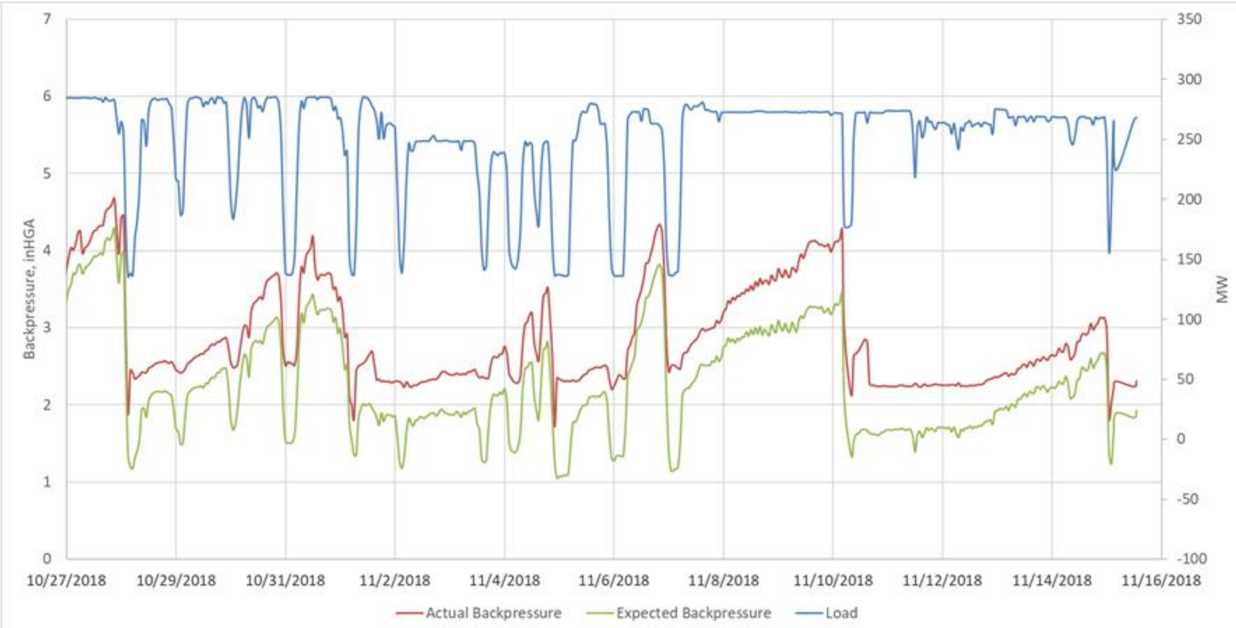


Figure 3-22 Condenser Performance – 11 Day Trend

On Figure 3-23 and 3-24, a trend of back pressure versus circulating water inlet temperature at high load shows a mixture of good performance and very poor performance, especially at lower river temperatures.

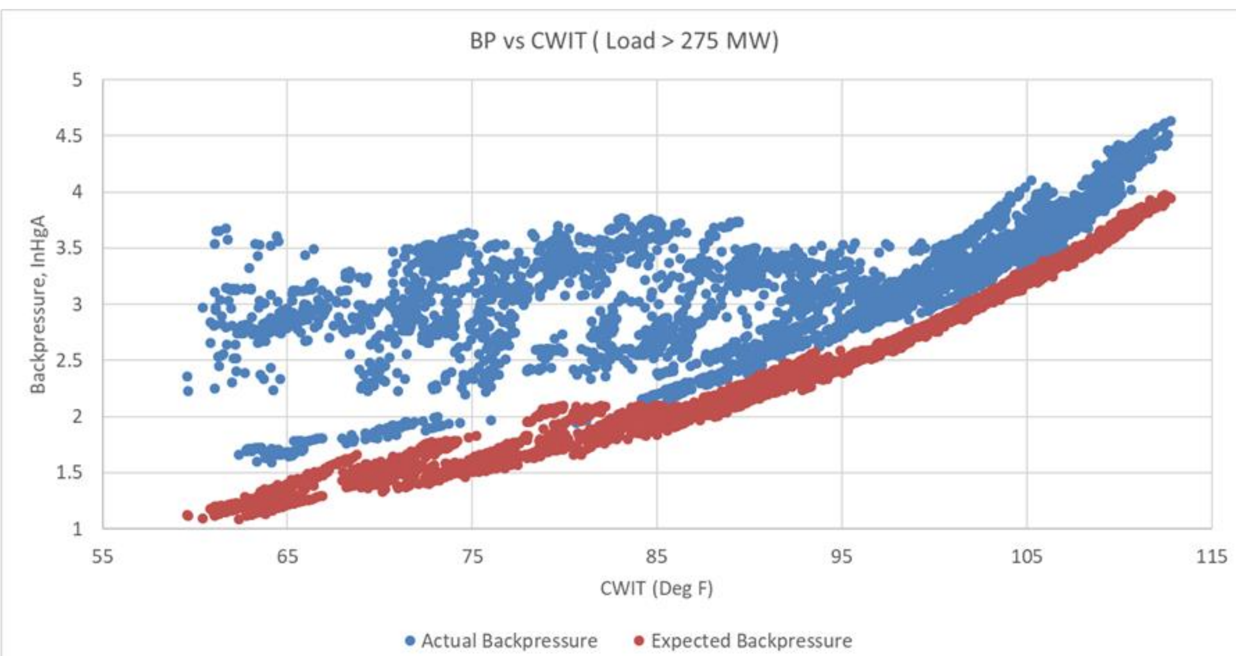


Figure 3-23 Condenser Back Pressure Versus Circulating Water Inlet Temperature

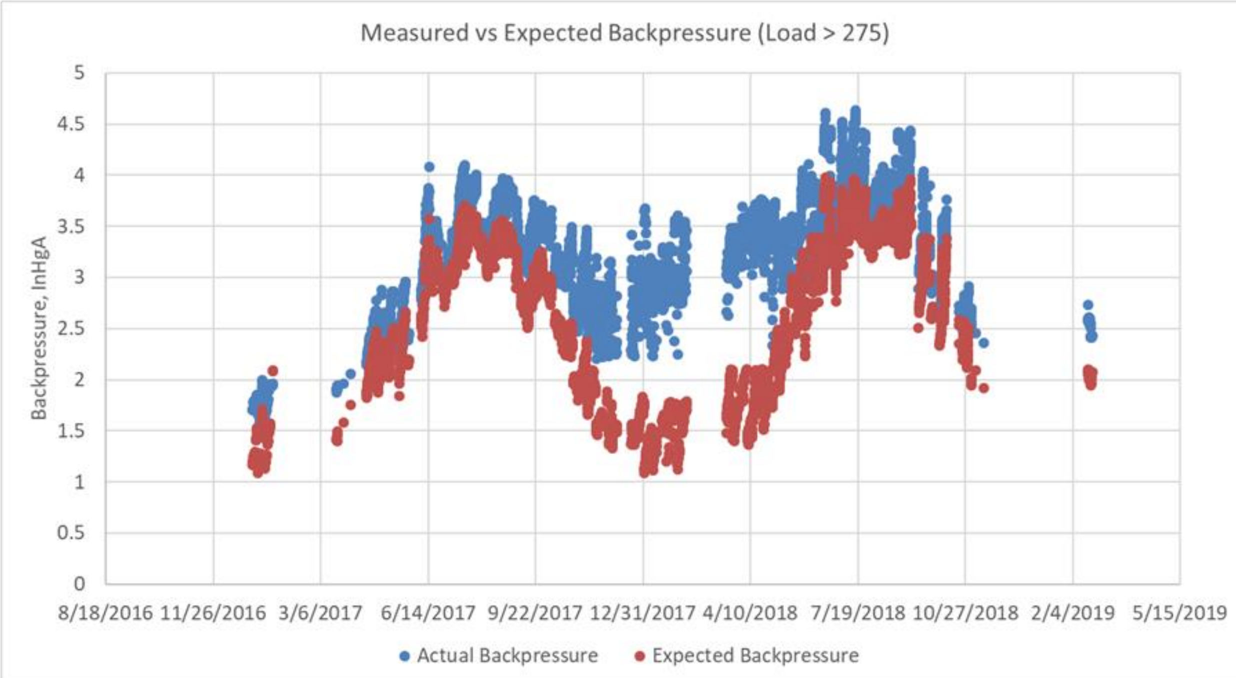


Figure 3-24 Condenser Back Pressure Versus Time at High Load

Condenser performance problems are unique to each unit and can be caused by a combination of factors. Considering the high availability, load capacity, and extent of condenser performance issues, this unit could be a candidate for added focus for improvement. If fouling the condenser is the primary concern felt by O&M personnel, payback on capital expenditure to rectify the situation may be too long, given this fuel cost. Adding backwash capability is likely to be cost prohibitive because of proximity of major piping work that would be required close to the turbine foundation. The addition of a debris filtering system would be beneficial and would be required before possible consideration of a ball cleaning system. The combined cost of these two capital improvements would likely be cost prohibitive.

4.0 Performance and CO_2 Production Estimates

High-level plant performance estimates were used to estimate the average annual CO_2 reduction. These performance benefits are summarized in Appendix B, Table B-1, Table B-2, Table B-3, and Table B-4, for A.B. Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3, respectively. It should be noted that some projects will have overlapping performance impacts and benefits, so that the overall net benefit for a series of projects considered together will likely differ from the sum of the individual project benefits listed in each table.

The annual CO_2 production estimates shown in Tables 4-1 through 4-4 were based on the following plant performance basis. Net capacity, capacity factor, and the average annual net plant heat rate were provided by average annual values from the most recent full year data (2017) provided by SNL and Ventyx Velocity data.

Table 4-1 Basis for A.B. Brown Unit 1 CO_2 Reduction Estimates

GROSS/NET CAPACITY (MW)	NET CAPACITY FACTOR (%)	AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH)	FUEL HEAT INPUT (MBTU/Y)	LB CO_2/ MBTU (HHV)	ANNUAL CO_2 (TONS/Y)
265/248	43.7	11,575	11,427,186	205.2	1,172,428

Table 4-2 Basis for A.B. Brown Unit 2 CO_2 Reduction Estimates

GROSS/NET CAPACITY (MW)	NET CAPACITY FACTOR (%)	AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH)	FUEL HEAT INPUT (MBTU/Y)	LB CO_2/ MBTU (HHV)	ANNUAL CO_2 (TONS/Y)
265/248	45.7	11,007	11,554,139	205.2	1,185,450

Table 4-3 Basis for F.B. Culley Unit 2 CO_2 Reduction Estimates

GROSS/NET CAPACITY (MW)	NET CAPACITY FACTOR (%)	AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH)	FUEL HEAT INPUT (MBTU/Y)	LB CO_2/ MBTU (HHV)	ANNUAL CO_2 (TONS/Y)
104/90	22.2	12,639	2,395,298	205.0	245.523

Table 4-4 Basis for F.B. Culley Unit 3 CO_2 Reduction Estimates

GROSS/NET CAPACITY (MW)	NET CAPACITY FACTOR (%)	AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH)	FUEL HEAT INPUT (MBTU/Y)	LB CO_2/ MBTU (HHV)	ANNUAL CO_2 (TONS/Y)
287/270	70.5	10,552	20,885,900	205.1	2,141,818

Where:

Fuel Heat Input [MBtu/y] =

Net Capacity [MW] * 1,000 kW/MW * Capacity Factor [%] * 8,760 h/y * NPHR [Btu/kWh, HHV]/ (1,000,000 Btu/MBtu)

Annual CO_2 Production [tons/y] =

Fuel Heat Input [MBtu/y] * CO_2 Production Rate [CO_2 emissions, lbm/MBtu of Fuel Burned]/ (2,000 lbm/ ton)

5.0 Capital Cost Estimates

High-level capital cost estimates were developed for each alternative and are detailed with each HRI project in Section 3.0. These estimates are summarized in Appendix B, Tables B-1, B-2, B-3, and B-4 and are based on the information available and should be considered preliminary for comparative purposes. The estimates are on an overnight basis (exclusive of escalation). The estimates represent the total capital requirement for each project, assuming a turnkey EPC project execution strategy. Pricing was based on similar project pricing or Black & Veatch's internal database. Black & Veatch has not developed preliminary equipment sizing or layouts to determine the feasibility of adding the proposed equipment or performing the modifications that will be required to support their installation. More detailed evaluations will be required to verify, refine, and confirm the viability of any of the proposed projects that require equipment modification or additional area.

6.1 Project Risk Considerations

Factors that influence the ability to maintain power plant efficiency and corresponding CO_2 emissions reductions on an annual basis are discussed in this section.

6.2 EFFICIENCY DIFFERENCES DUE TO OPERATING PROFILE

Efficiency is significantly affected when plants operate under off-design conditions, particularly part-load operation or with frequent starts. The future operating characteristics of A.B. Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3 can have a significant impact on the ability to achieve the expected efficiency gains and associated reduced CO_2 emissions.

6.2.1 Operating Load and Load Factor

Plants that operate with a low average output will have lower efficiency than their full-load design efficiency. Load or capacity factor describes the plant output over a period of time relative to the potential maximum; it depends on both running time at a given load and the operating load. Therefore, annual variation in both operating load and load factor can alter the CO_2 emissions as well as the benefit of capital projects intended to reduce plant emissions. Variation in the unit load factor can significantly impact the annual CO_2 emissions for a given generation rate.

Capital projects that may offer benefit in reducing outage duration or frequency may also see some benefit mitigated. For example, a plant may be able to extend the time between major overhauls and shorten the time required for a major overhaul of the steam turbine because of improved design. However, this could increase the hours the plant may run in a year and could increase the annual CO_2 emissions. Plant generation may be limited to avoid exceeding annual CO_2 emissions rates, negating some of the potential benefit of the upgrade.

6.2.2 Transient Operation

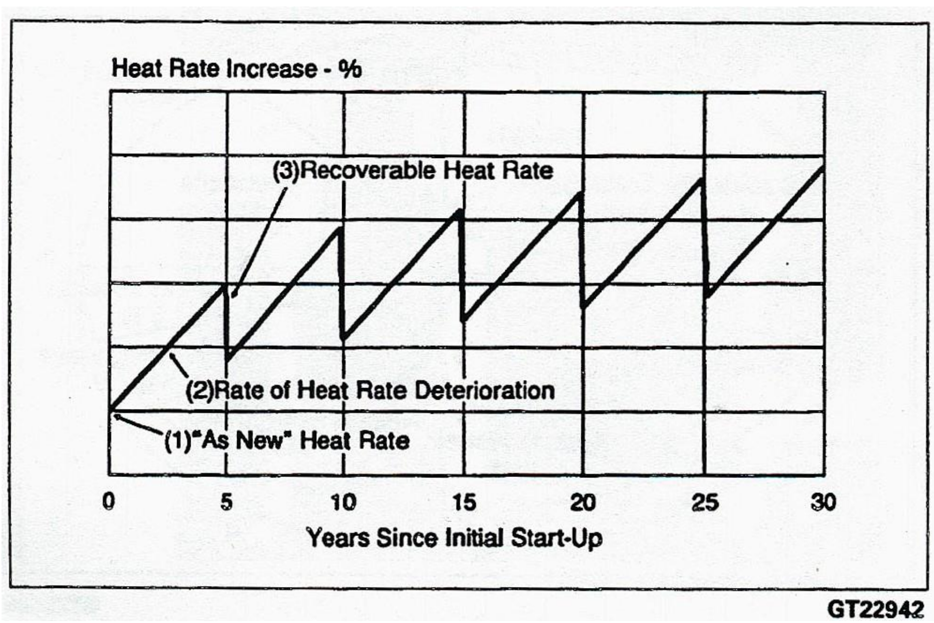
The greater the number of transients from steady state operating conditions that the plant experiences, the greater the impact to annual efficiency. During each of these transients, the plant will not be operating at peak performance. The influence of increasing renewable energy can affect the frequency of transient operation. Operation in frequency response mode, where steam flow and boiler firing fluctuate to regulate system frequency, can lead to more transients. Other situations may require frequent load changes, notably in response to power system constraints or power market pricing.

6.2.3 Plant Starts

Frequent shutdowns incur significant off-load energy losses, particularly during subsequent plant startup. Power plants operating in volatile or competitive markets, or operating as marginal providers of power, may be required to shut down frequently. This can also lead to deterioration in equipment condition, which will further affect annual plant efficiency and increase CO_2 emissions.

6.3 DETERIORATION

Figure 6-1 illustrates the characteristic performance deterioration that the steam turbine can be expected to experience between major overhauls. In addition, the ability of the steam turbine to economically recover from any deterioration in performance during a regularly scheduled maintenance overhaul is also illustrated. Any steam turbine retrofit is expected to experience a similar pattern of increasing deterioration, where increasingly, a portion of this deterioration is not viably recovered, even following a major overhaul. Turbine suppliers recognize the importance of sustained efficiency and work to incorporate features that result in superior sustained efficiency. The degree to which deterioration can be minimized by new designs is in large part dependent on the current design and feasible proven options. The ability of the steam turbine to sustain efficiency is a significant factor in achieving year after year CO_2 reduction.



Source: Steam Turbine Sustained Efficiency, GER-3750C

Figure 6-1 Steam Turbine Generator Heat Rate Change Over Time

Other plant equipment is also expected to see performance deterioration over the operating life after capital projects are implemented. The degree of deterioration and the rate at which it occurs is difficult to predict and presents a risk to the longer-term ability of the plants to sustain their efficiency gains.

6.4 PLANT MAINTENANCE

As well as ensuring plant availability, a key requirement of plant maintenance is to maintain peak operating efficiency. Improved maintenance and component replacement and upgrading can reduce energy losses.

Any poorly performing auxiliary equipment or individual components that affect performance will also contribute to the overall deterioration of plant performance over time, compounding the effects of deterioration in major components, such as the steam turbine. While not an intended outcome, plant upgrades can also result in increased maintenance if the expected improvements cannot be not achieved without increased or more complicated plant maintenance. Tables B-1, B-2, B-3, and B-4 (Appendix B) include an order-of-magnitude rating of comparative operating and maintenance cost impact associated with each of the given projects.

6.5 FUEL QUALITY IMPACTS

Variation in fuel quality can have a significant impact on the boiler efficiency. Reduced boiler efficiency will increase the required fuel heat input for a given generation which will increase CO_2 emissions. Variation in fuel composition can also have an effect on the pounds of CO_2 emission/MBtu of fuel burned.

6.6 AMBIENT CONDITIONS

Variation in ambient conditions can affect the condenser operating pressure and the resulting steam turbine output. In particular, higher wet bulb temperatures can have a significant impact on plant heat rate. Variation in annual average turbine back pressure because of wet bulb will affect the expected benefits of several of the heat rejection and steam turbine capital improvement projects.

Appendix A. Abbreviations and Acronyms

°F	Degrees Fahrenheit
ACE	Affordable Clean Energy (Plan)
ADSP	Advanced Design Steam Path
AH	Air Heater
AQCS	Air Quality Control System
BSER	Best System of Emission Reduction
Btu	British Thermal Unit
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPP	Clean Power Plan
DCA	Drain Cooler Approach
DCS	Distributed Control System
EGU	Electric Generating Unit
EPA	United States Environmental Protection Agency
EPRI	Electric Power Research Institute
FD	Forced Draft
Ft	Feet
GE	General Electric
GHG	Greenhouse Gas
gpm	Gallons per minute
h	Hour
HHV	Higher Heating Value
hp	Horsepower
HP	High Pressure
HRI	Heat Rate Improvement
ID	Induced Draft
IGBT	Insulated-Gate Bipolar Transistor
in. HgA	Inches of Mercury – Absolute
IP	Intermediate Pressure
IRP	Integrated Resource Plan
ISB	Intelligent Sootblowing
kW	Kilowatt
kWh	Kilowatt hour
lbm	Pound
LP	Low Pressure
MBtu	Million British Thermal Units

MW	Megawatt
NO_x	Nitrogen Oxide
NP	Normal Pressure
NPHR	Net Plant Heat Rate
NSR	New Source Review
OEM	Original Equipment Manufacturer
PA	Primary Air
PJFF	Pulse Jet Fabric Filter
rpm	Revolutions per Minute
SLR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
STG	Steam Turbine Generator
TTD	Terminal Temperature Difference
VFD	Variable Frequency Drive
VWO	Valve Wide Open
y	Year

Appendix B. Capital Cost and Performance Estimates

Table B-1 A.B. Brown Unit 1 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Steam Turbine	HP/IP Upgrades or Full Steam Path Upgrades	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Economizer	Redesign or Replacement	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Air Heater/Duct Leakage	Air Heater Basket, Seal, and Sector Plate Replacement	850	0.50	57.88	57,136	5,862	145.0	Low
Air Heater/Duct Leakage	Air Heater (Steam Coil) System Repairs	350	0.10	11.6	11,427	1,172	298.5	N/A
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Circulating Water Pumps	2,100	N/A	N/A	N/A	N/A	N/A	Low
Variable Frequency Drive (VFD) Upgrades	Cooling Tower Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,000	0.43	50.3	49,701	5,099	392.2	Low/Med
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	2,900	2.39	276.50	272,973	28,007	103.5	Low
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess O_2)	500	0.23	26.6	26,283	2,697	185.4	Low
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess O_2)	500	0.43	49.77	49,137	5,041	99.2	N/A

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess O_2)	500.0	0.60	69.5	68,563	7,035	71.1	Low
Intelligent Soot Blowing (ISB)	Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate.	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Improved O&M Practices	Heat rate improvement training.	15	0.30	34.7	34,282	3,517	4.3	Low
Improved O&M Practices	On-site heat rate appraisals.	Variable	Variable	N/A	N/A	N/A	N/A	Low
Improved O&M Practices	Improved Condenser Cleaning Strategies	N/A	0.15	17.4	17,141	1,759	N/A	Low

Table B-2 A.B. Brown Unit 2 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Steam Turbine	HP/IP Upgrades or Full Steam Path Upgrades	Not Recommended	N/A	N/A	N/A	N/A	N/A	No change
Economizer	Redesign or Replacement	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Air Heater/Duct Leakage	Air Heater Basket, Seal, and Sector Plate Replacement	850	0.50	55.0	57,771	5,927	143.4	Low
Air Heater/Duct Leakage	Air Heater (Steam Coil) System Repairs	350	0.10	11.0	11,554	1,185	295.2	Low
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	Not Recommended	N/A	N/A	N/A	N/A	N/A	Low
Variable Frequency Drive (VFD) Upgrades	Circulating Water Pumps	2,100	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Cooling Tower Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,000	0.26	28.6	30,015	3,080	649.4	N/A
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	2,900	1.33	146.3	153,608	15,760	184.0	Low
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess O_2)	500	0.23	25.3	26,575	2,727	183.4	Low/Med
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess O_2)	500	0.43	47.33	49,683	5,097	98.1	Low

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess O_2)	500	0.60	66.0	69,325	7,113	70.3	Low
Intelligent Soot Blowing (ISB)	Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate.	Not Recommended	N/A	N/A	N/A	N/A	N/A	Low
Improved O&M Practices	Heat rate improvement training.	15	0.30	33.0	34,662	3,556	4.2	Low
Improved O&M Practices	On-site heat rate appraisals.	Variable	Variable	N/A	N/A	N/A	N/A	Low
Improved O&M Practices	Improved Condenser Cleaning Strategies	N/A	N/A	N/A	N/A	N/A	N/A	Low

Table B-3 F.B. Culley Unit 2 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Steam Turbine	Full steam path upgrades.	10,400	1.4	176.9	33,534	3.44	3,025,611	No change
Economizer	Redesign or Replacement	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Air Heater/Duct Leakage	Air Heater Basket, Seal, and Sector Plate Replacement	476	0.50	63.2	11,976	1.23	387,744	Low
Air Heater/Duct Leakage	Air Heater (Steam Coil) System Repairs	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	600	0.60	75.8	14,372	1.47	407,294	N/A
Variable Frequency Drive (VFD) Upgrades	Circulating Water Pumps	900	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Cooling Tower Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,000	0.48	60.9	11,549	1.18	1,689,525	N/A
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess O_2)	500	0.26	32.9	6,228	0.64	783,257	Low/Med
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess O_2)	500	0.47	59.40	11,258	1.15	433,291	Low

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess O_2)	500	0.62	78.4	14,851	1.52	328,463	Low
Intelligent Soot Blowing (ISB)	Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate.	350	0.10	12.64	2,395	0.25	1,425,528	Low
Improved O&M Practices	Heat rate improvement training.	15	0.30	37.9	7,186	0.74	20,365	Low
Improved O&M Practices	On-site heat rate appraisals.	Variable	Variable	N/A	N/A	N/A	N/A	N/A
Improved O&M Practices	Improved Condenser Cleaning Strategies	N/A	0.42	53.1	10,060	1.03	N/A	Low

Table B-4 F.B. Culley Unit 3 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Steam Turbine	HP/IP upgrades	19,900	1.5	158.3	313,289	32,127	619.4	No change
Economizer	Major redesign with additional tube passes.	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Air Heater/Duct Leakage	Air Heater Basket, Seal, and Sector Plate Replacement	750	0.50	52.8	104,430	10,709	70.0	Low
Air Heater/Duct Leakage	Air Heater (Steam Coil) System Repairs	350	0.10	10.6	20,886	2,142	163	Low
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Circulating Water Pumps	2,100	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Cooling Tower Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,000	0.51	54.3	107,412	11,015	181.6	N/A
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess O_2)	500	0.25	26.4	52,215	5,355	93.4	Low/Med
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess O_2)	500	0.46	48.54	96,075	9,852	50.7	Low

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess O_2)	500	0.62	65.4	129,493	13,279	37.7	Low
Intelligent Soot Blowing (ISB)	Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate.	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Improved O&M Practices	Heat rate improvement training.	15	0.30	31.7	62,658	6,425	2.3	Low
Improved O&M Practices	On-site Heat Rate Appraisals	Variable	Variable	N/A	N/A	N/A	N/A	N/A
Improved O&M Practices	Improved Condenser Cleaning Strategies	N/A	0.44	46.4	91,898	9,424	#VALUE!	Low

Table B-5 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report – 5 year)

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (5-year useful life)	Cost per ton of CO2 ($) (5-year useful Life)
ABB1	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	58	58,716	130.1	0	0	130.1	6.5	8.5	39.9	29.00
ABB1	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11.6	11,768	26.1	0	0	26.1	13.4	15.4	43.93310101	59.71
ABB1	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	420.0	N/A
ABB1	Induced Draft Fans	2021	2,900	2.2	254.65	258,330	572.2	-2	0	570.2	5.1	7.1	9.764152778	22.49
ABB1	Forced Draft Fans	2021	2,000	0.5	58	58,711	130.1	-2	0	128.1	15.6	17.6	271.9	68.23
ABB1	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.23	26.6	26,984	59.8	0	0	59.8	8.4	10.4	40.22590404	37.08
ABB1	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	50	50,489	111.8	0	0	111.8	4.5	6.5	-11.8	19.84
ABB1	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	69.5	70,504	156.2	0	0	156.2	3.2	5.2	-56.17667929	14.22
ABB1	Heat Rate Improvement Training.	2021	15	0.3	35	35,201	78.0	0	0	78.0	0.2	2.2	-75.0	0.85
ABB1	On-Site Heat Rate Appraisals.	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB1	Improved Condenser Cleaner Strategies	2021	N/A	0.2	17	17,651	39.1	0	0	39.1	N/A	N/A	N/A	N/A
ABB1	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-17,753	-39.3	0	N/A	-39.3	-19.1	-17.1	189.3	-75.26
ABB1	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-37,433	-82.9	0	N/A	-82.9	-13.0	-11.0	297.9	-50.94
ABB1	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-63,302	-140.2	0	N/A	-140.2	-10.0	-8.0	420.2	-39.15
ABB2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	55	58,348	129.2	0	0	129.2	6.6	8.6	40.8	29.00

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (5-year useful life)	Cost per ton of CO2 ($) (5-year useful Life)
ABB2	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11	11,670	25.8	0	0	25.8	13.5	15.5	44.15010234	59.71
ABB2	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	420.0	N/A
ABB2	Induced Draft Fans	2021	2,900	1.2	132.084	140,125	310.4	0	0	-2.0	-1,450.0	-1448.0	582	41.22
ABB2	Forced Draft Fans	2021	2,000	0.2	22	23,354	51.7	0	0	-2.0	-1,000.0	-998.0	402.0	170.59
ABB2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	3	25.3	26,840	59.5	0	0	59.5	8.4	10.4	40.54523538	2.84
ABB2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	47	50,211	111.2	0	0	111.2	4.5	6.5	-11.2	19.84
ABB2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	66	70,018	155.1	0	0	155.1	3.2	5.2	-55.09938596	14.22
ABB2	Heat Rate Improvement Training	2021	15	0.3	33	35,009	77.5	0	0	77.5	0.2	2.2	-74.5	0.85
ABB2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Improved Condenser Cleaner Strategies	2021	N/A	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-18,565	-41.1	0	N/A	-41.1	-18.2	-16.2	239.3250631	-100.34
ABB2	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-39,146	-86.7	0	N/A	-86.7	-12.4	-10.4	282.9	-47.39
ABB2	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-66,199	-146.6	0	N/A	-146.6	-9.5	-7.5	340.2219394	-27.96
FBC2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	476	0.5	63	12,782	28.3	0	0	28.3	16.8	18.8	66.9	16.24
FBC2	Circulating Water Pumps	2021	900	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	180	N/A
FBC2	Boiler Feed Pump	2021	600	0.6	76	15,337	34.0	-2	0	32.0	18.8	20.8	88.0	17.06
FBC2	Forced Draft Fans	2021	2,000	0.5	63.195	12,781	28.3	-2	0	26.3	76.0	78.0	373.6878337	68.23

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (5-year useful life)	Cost per ton of CO2 ($) (5-year useful Life)
FBC2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.3	33	6,654	14.7	0	0	14.7	33.9	35.9	85.3	32.81
FBC2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.47	59.4	12,014	26.6	0	0	26.6	18.8	20.8	73.38804211	18.15
FBC2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	78	15,856	35.1	0	0	35.1	14.2	16.2	64.9	13.76
FBC2	Synchronized Controlled Sootblowing System	2021	350	0.1	12.64	2,556	5.7	0	0	5.7	61.8	63.8	64.33711872	59.71
FBC2	Heat Rate Improvement Training	2021	15	0.3	38	7,665	17.0	0	0	17.0	0.9	2.9	-14.0	0.85
FBC2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC2	Improved Condenser Cleaner Strategies	2021	N/A	0.4	53	10,740	23.8	0	0	23.8	N/A	N/A	N/A	N/A
FBC3	HP/IP Upgrades	2022	19,900	1.5	158.3	280,580	621.5	0	0	621.5	32.0	35.0	3358.478728	226.31
FBC3	Air Heater Basket, Seal, and Sector Plate Replacement	2022	750	0.5	53	93,586	207.3	0	0	207.3	3.6	6.6	-57.3	25.59
FBC3	Air Heater (Steam Coil) System Repairs	2022	350	0.1	10.6	18,788	41.6	0	0	41.6	8.4	11.4	28.38202472	59.71
FBC3	Circulating Water Pumps	2022	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	420.0	N/A
FBC3	Forced Draft Fans	2022	2,000	0.46	48.5392	86,034	190.6	-2	0	188.6	10.6	13.6	211.424224	74.17
FBC3	Neural Network with 0.25% Reduction in Excess O_2	2022	500	0.3	26	46,793	103.7	0	0	103.7	4.8	7.8	-3.7	34.12
FBC3	Neural Network with 0.50% Reduction in Excess O_2	2022	500	0.46	48.54	86,035	190.6	0	0	190.6	2.6	5.6	-90.57891699	18.54

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (5-year useful life)	Cost per ton of CO2 ($) (5-year useful Life)
FBC3	Neural Network with 0.75% Reduction in Excess O_2	2022	500	0.6	65	115,919	256.8	0	0	256.8	1.9	4.9	-156.8	13.76
FBC3	Heat Rate Improvement Training	2022	15	0.3	31.7	56,187	124.5	0	0	124.5	0.1	3.1	-121.4613034	0.85
FBC3	On-Site Heat Rate Appraisals	2022	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC3	Improved Condenser Cleaner Strategies	2022	N/A	0.44	46.4	82,242	182.2	0	0	182.2	N/A	N/A	N/A	N/A
FBC3	Economizer (1 Tube Pass)	2022	750	-0.1	-14	-25,169	-55.8	0	195.0	139.2	5.4	8.4	10.8	70.12
FBC3	Economizer (2 Tube Pass)	2022	1,075	-0.28	-29.1	-51,578	-114.3	0	288.8	174.6	6.2	9.2	40.4	92.79
FBC3	Economizer (3 Tube Pass)	2022	1,400	-0.4	-45	-79,583	-176.3	0	382.6	206.3	6.8	9.8	73.7	117.78

Table B-6 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report –10 year)

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (10-year useful life)	Cost per ton of CO2 ($) (10-year useful Life)
ABB1	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	58	58,716	130.1	0	0	130.1	6.5	8.5	-45.1	14.50
ABB1	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11.6	11,768	26.1	0	0	26.1	13.4	15.4	8.9	29.85
ABB1	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	210.0	N/A
ABB1	Induced Draft Fans	2021	2,900	2.2	254.65	258,330	572.2	-2	0	570.2	5.1	7.1	-280.2	11.24
ABB1	Forced Draft Fans	2021	2,000	0.5	58	58,711	130.1	-2	0	128.1	15.6	17.6	71.9	34.12
ABB1	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.23	26.6	26,984	59.8	0	0	59.8	8.4	10.4	-9.8	18.54
ABB1	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	50	50,489	111.8	0	0	111.8	4.5	6.5	-61.8	9.92
ABB1	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	69.5	70,504	156.2	0	0	156.2	3.2	5.2	-106.2	7.11
ABB1	Heat Rate Improvement Training.	2021	15	0.3	35	35,201	78.0	0	0	78.0	0.2	2.2	-76.5	0.43
ABB1	On-Site Heat Rate Appraisals.	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB1	Improved Condenser Cleaner Strategies	2021	N/A	0.2	17	17,651	39.1	0	0	39.1	N/A	N/A	N/A	N/A
ABB1	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-17,753	-39.3	0	N/A	-39.3	-19.1	-17.1	114.3	-37.63
ABB1	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-37,433	-82.9	0	N/A	-82.9	-13.0	-11.0	190.4	-25.47
ABB1	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-63,302	-140.2	0	N/A	-140.2	-10.0	-8.0	280.2	-19.58

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (10-year useful life)	Cost per ton of CO2 ($) (10-year useful Life)
ABB2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	55	58,348	129.2	0	0	129.2	6.6	8.6	-44.2	14.50
ABB2	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11	11,670	25.8	0	0	25.8	13.5	15.5	9.2	29.85
ABB2	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	210.0	N/A
ABB2	Induced Draft Fans	2021	2,900	1.2	132.084	140,125	310.4	0	0	-2.0	-1,450.0	-1448.0	292.0	20.61
ABB2	Forced Draft Fans	2021	2,000	0.2	22	23,354	51.7	0	0	-2.0	-1,000.0	-998.0	202.0	85.29
ABB2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	3	25.3	26,840	59.5	0	0	59.5	8.4	10.4	-9.5	1.42
ABB2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	47	50,211	111.2	0	0	111.2	4.5	6.5	-61.2	9.92
ABB2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	66	70,018	155.1	0	0	155.1	3.2	5.2	-105.1	7.11
ABB2	Heat Rate Improvement Training	2021	15	0.3	33	35,009	77.5	0	0	77.5	0.2	2.2	-76.0	0.43
ABB2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Improved Condenser Cleaner Strategies	2021	N/A	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-18,565	-41.1	0	N/A	-41.1	-18.2	-16.2	139.3	-50.17
ABB2	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-39,146	-86.7	0	N/A	-86.7	-12.4	-10.4	182.9	-23.69
ABB2	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-66,199	-146.6	0	N/A	-146.6	-9.5	-7.5	240.2	-13.98

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (10-year useful life)	Cost per ton of CO2 ($) (10-year useful Life)
FBC2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	476	0.5	63	12,782	28.3	0	0	28.3	16.8	18.8	19.3	8.12
FBC2	Circulating Water Pumps	2021	900	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	90.0	N/A
FBC2	Boiler Feed Pump	2021	600	0.6	76	15,337	34.0	-2	0	32.0	18.8	20.8	28.0	8.53
FBC2	Forced Draft Fans	2021	2,000	0.5	63.195	12,781	28.3	-2	0	26.3	76.0	78.0	173.7	34.12
FBC2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.3	33	6,654	14.7	0	0	14.7	33.9	35.9	35.3	16.40
FBC2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.47	59.4	12,014	26.6	0	0	26.6	18.8	20.8	23.4	9.07
FBC2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	78	15,856	35.1	0	0	35.1	14.2	16.2	14.9	6.88
FBC2	Synchronized Controlled Sootblowing System	2021	350	0.1	12.64	2,556	5.7	0	0	5.7	61.8	63.8	29.3	29.85
FBC2	Heat Rate Improvement Training	2021	15	0.3	38	7,665	17.0	0	0	17.0	0.9	2.9	-15.5	0.43
FBC2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC2	Improved Condenser Cleaner Strategies	2021	N/A	0.4	53	10,740	23.8	0	0	23.8	N/A	N/A	N/A	N/A
FBC3	HP/IP Upgrades	2022	19,900	1.5	158.3	280,580	621.5	0	0	621.5	32.0	35.0	1,368.5	113.16
FBC3	Air Heater Basket, Seal, and Sector Plate Replacement	2022	750	0.5	53	93,586	207.3	0	0	207.3	3.6	6.6	-132.3	12.79
FBC3	Air Heater (Steam Coil) System Repairs	2022	350	0.1	10.6	18,788	41.6	0	0	41.6	8.4	11.4	-6.6	29.85

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (10-year useful life)	Cost per ton of CO2 ($) (10-year useful Life)
FBC3	Circulating Water Pumps	2022	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	210.0	N/A
FBC3	Forced Draft Fans	2022	2,000	0.46	48.5392	86,034	190.6	-2	0	188.6	10.6	13.6	11.4	37.08
FBC3	Neural Network with 0.25% Reduction in Excess O_2	2022	500	0.3	26	46,793	103.7	0	0	103.7	4.8	7.8	-53.7	17.06
FBC3	Neural Network with 0.50% Reduction in Excess O_2	2022	500	0.46	48.54	86,035	190.6	0	0	190.6	2.6	5.6	-140.6	9.27
FBC3	Neural Network with 0.75% Reduction in Excess O_2	2022	500	0.6	65	115,919	256.8	0	0	256.8	1.9	4.9	-206.8	6.88
FBC3	Heat Rate Improvement Training	2022	15	0.3	31.7	56,187	124.5	0	0	124.5	0.1	3.1	-123.0	0.43
FBC3	On-Site Heat Rate Appraisals	2022	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC3	Improved Condenser Cleaner Strategies	2022	N/A	0.44	46.4	82,242	182.2	0	0	182.2	N/A	N/A	N/A	N/A
FBC3	Economizer (1 Tube Pass)	2022	750	-0.1	-14	-25,169	-55.8	0	195.0	139.2	5.4	8.4	-64.2	35.06
FBC3	Economizer (2 Tube Pass)	2022	1,075	-0.28	-29.1	-51,578	-114.3	0	288.8	174.6	6.2	9.2	-67.1	46.40
FBC3	Economizer (3 Tube Pass)	2022	1,400	-0.4	-45	-79,583	-176.3	0	382.6	206.3	6.8	9.8	-66.3	58.89

Table B-7 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report –15 year)

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (15-year useful life)	Cost per ton of CO2 ($) (15-year useful Life)
ABB1	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	58	58,716	130.1	0	0	130.1	6.5	8.5	-73.4	9.67
ABB1	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11.6	11,768	26.1	0	0	26.1	13.4	15.4	-2.7	19.90
ABB1	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
ABB1	Induced Draft Fans	2021	2,900	2.2	254.65	258,330	572.2	-2	0	570.2	5.1	7.1	-376.9	7.50
ABB1	Forced Draft Fans	2021	2,000	0.5	58	58,711	130.1	-2	0	128.1	15.6	17.6	5.3	22.74
ABB1	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.23	26.6	26,984	59.8	0	0	59.8	8.4	10.4	-26.4	12.36
ABB1	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	50	50,489	111.8	0	0	111.8	4.5	6.5	-78.5	6.61
ABB1	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	69.5	70,504	156.2	0	0	156.2	3.2	5.2	-122.8	4.74
ABB1	Heat Rate Improvement Training.	2021	15	0.3	35	35,201	78.0	0	0	78.0	0.2	2.2	-77.0	0.28
ABB1	On-Site Heat Rate Appraisals.	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB1	Improved Condenser Cleaner Strategies	2021	N/A	0.2	17	17,651	39.1	0	0	39.1	N/A	N/A	N/A	N/A
ABB1	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-17,753	-39.3	0	N/A	-39.3	-19.1	-17.1	89.3	-25.09
ABB1	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-37,433	-82.9	0	N/A	-82.9	-13.0	-11.0	154.6	-16.98
ABB1	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-63,302	-140.2	0	N/A	-140.2	-10.0	-8.0	233.6	-13.05

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (15-year useful life)	Cost per ton of CO2 ($) (15-year useful Life)
ABB2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	55	58,348	129.2	0	0	129.2	6.6	8.6	-72.6	9.67
ABB2	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11	11,670	25.8	0	0	25.8	13.5	15.5	-2.5	19.90
ABB2	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
ABB2	Induced Draft Fans	2021	2,900	1.2	132.084	140,125	310.4	0	0	-2.0	-1,450.0	-1448.0	195.3	13.74
ABB2	Forced Draft Fans	2021	2,000	0.2	22	23,354	51.7	0	0	-2.0	-1,000.0	-998.0	135.3	56.86
ABB2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	3	25.3	26,840	59.5	0	0	59.5	8.4	10.4	-26.1	0.95
ABB2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	47	50,211	111.2	0	0	111.2	4.5	6.5	-77.9	6.61
ABB2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	66	70,018	155.1	0	0	155.1	3.2	5.2	-121.8	4.74
ABB2	Heat Rate Improvement Training	2021	15	0.3	33	35,009	77.5	0	0	77.5	0.2	2.2	-76.5	0.28
ABB2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Improved Condenser Cleaner Strategies	2021	N/A	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-18,565	-41.1	0	N/A	-41.1	-18.2	-16.2	106.0	-33.45
ABB2	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-39,146	-86.7	0	N/A	-86.7	-12.4	-10.4	149.6	-15.80
ABB2	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-66,199	-146.6	0	N/A	-146.6	-9.5	-7.5	206.9	-9.32

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (15-year useful life)	Cost per ton of CO2 ($) (15-year useful Life)
FBC2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	476	0.5	63	12,782	28.3	0	0	28.3	16.8	18.8	3.4	5.41
FBC2	Circulating Water Pumps	2021	900	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	60.0	N/A
FBC2	Boiler Feed Pump	2021	600	0.6	76	15,337	34.0	-2	0	32.0	18.8	20.8	8.0	5.69
FBC2	Forced Draft Fans	2021	2,000	0.5	63.195	12,781	28.3	-2	0	26.3	76.0	78.0	107.0	22.74
FBC2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.3	33	6,654	14.7	0	0	14.7	33.9	35.9	18.6	10.94
FBC2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.47	59.4	12,014	26.6	0	0	26.6	18.8	20.8	6.7	6.05
FBC2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	78	15,856	35.1	0	0	35.1	14.2	16.2	-1.8	4.59
FBC2	Synchronized Controlled Sootblowing System	2021	350	0.1	12.64	2,556	5.7	0	0	5.7	61.8	63.8	17.7	19.90
FBC2	Heat Rate Improvement Training	2021	15	0.3	38	7,665	17.0	0	0	17.0	0.9	2.9	-16.0	0.28
FBC2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC2	Improved Condenser Cleaner Strategies	2021	N/A	0.4	53	10,740	23.8	0	0	23.8	N/A	N/A	N/A	N/A
FBC3	HP/IP Upgrades	2022	19,900	1.5	158.3	280,580	621.5	0	0	621.5	32.0	35.0	705.1	75.44
FBC3	Air Heater Basket, Seal, and Sector Plate Replacement	2022	750	0.5	53	93,586	207.3	0	0	207.3	3.6	6.6	-157.3	8.53
FBC3	Air Heater (Steam Coil) System Repairs	2022	350	0.1	10.6	18,788	41.6	0	0	41.6	8.4	11.4	-18.3	19.90

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (15-year useful life)	Cost per ton of CO2 ($) (15-year useful Life)
FBC3	Circulating Water Pumps	2022	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
FBC3	Forced Draft Fans	2022	2,000	0.46	48.5392	86,034	190.6	-2	0	188.6	10.6	13.6	-55.2	24.72
FBC3	Neural Network with 0.25% Reduction in Excess O_2	2022	500	0.3	26	46,793	103.7	0	0	103.7	4.8	7.8	-70.3	11.37
FBC3	Neural Network with 0.50% Reduction in Excess O_2	2022	500	0.46	48.54	86,035	190.6	0	0	190.6	2.6	5.6	-157.2	6.18
FBC3	Neural Network with 0.75% Reduction in Excess O_2	2022	500	0.6	65	115,919	256.8	0	0	256.8	1.9	4.9	-223.4	4.59
FBC3	Heat Rate Improvement Training	2022	15	0.3	31.7	56,187	124.5	0	0	124.5	0.1	3.1	-123.5	0.28
FBC3	On-Site Heat Rate Appraisals	2022	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC3	Improved Condenser Cleaner Strategies	2022	N/A	0.44	46.4	82,242	182.2	0	0	182.2	N/A	N/A	N/A	N/A
FBC3	Economizer (1 Tube Pass)	2022	750	-0.1	-14	-25,169	-55.8	0	195.0	139.2	5.4	8.4	-89.2	23.37
FBC3	Economizer (2 Tube Pass)	2022	1,075	-0.28	-29.1	-51,578	-114.3	0	288.8	174.6	6.2	9.2	-102.9	30.93
FBC3	Economizer (3 Tube Pass)	2022	1,400	-0.4	-45	-79,583	-176.3	0	382.6	206.3	6.8	9.8	-113	39.26

Table B-8 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report –20 year)

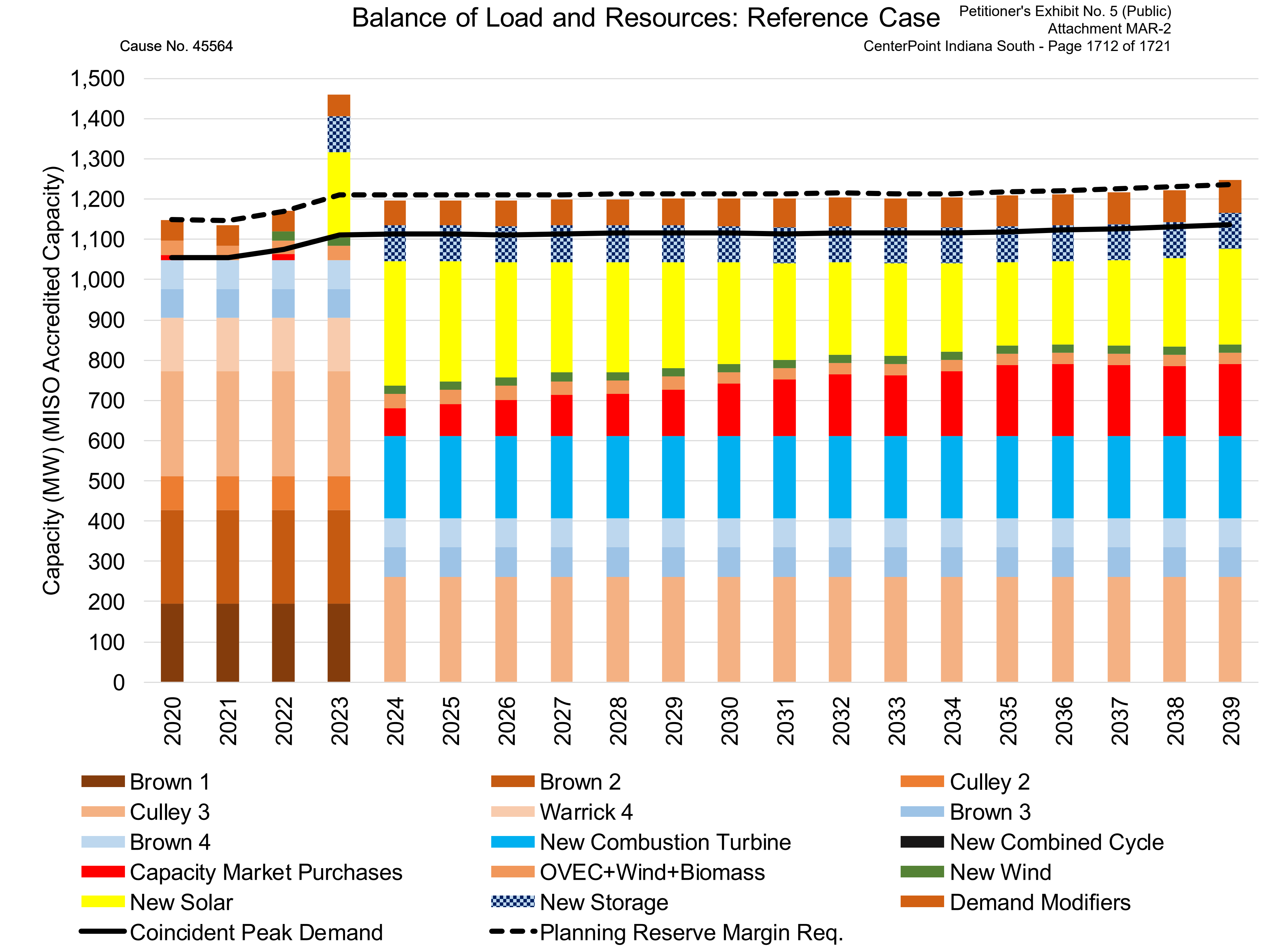
Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (20-year useful life)	Cost per ton of CO2 ($) (20-year useful Life)
ABB1	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	58	58,716	130.1	0	0	130.1	6.5	8.5	-73.4	9.67
ABB1	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11.6	11,768	26.1	0	0	26.1	13.4	15.4	-2.7	19.90
ABB1	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
ABB1	Induced Draft Fans	2021	2,900	2.2	254.65	258,330	572.2	-2	0	570.2	5.1	7.1	-376.9	7.50
ABB1	Forced Draft Fans	2021	2,000	0.5	58	58,711	130.1	-2	0	128.1	15.6	17.6	5.3	22.74
ABB1	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.23	26.6	26,984	59.8	0	0	59.8	8.4	10.4	-26.4	12.36
ABB1	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	50	50,489	111.8	0	0	111.8	4.5	6.5	-78.5	6.61
ABB1	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	69.5	70,504	156.2	0	0	156.2	3.2	5.2	-122.8	4.74
ABB1	Heat Rate Improvement Training.	2021	15	0.3	35	35,201	78.0	0	0	78.0	0.2	2.2	-77.0	0.28
ABB1	On-Site Heat Rate Appraisals.	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB1	Improved Condenser Cleaner Strategies	2021	N/A	0.2	17	17,651	39.1	0	0	39.1	N/A	N/A	N/A	N/A
ABB1	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-17,753	-39.3	0	N/A	-39.3	-19.1	-17.1	76.8	-18.81
ABB1	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-37,433	-82.9	0	N/A	-82.9	-13.0	-11.0	136.7	-12.73
ABB1	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-63,302	-140.2	0	N/A	-140.2	-10.0	-8.0	210.2	-9.79
ABB2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	55	58,348	129.2	0	0	129.2	6.6	8.6	-72.6	9.67

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (20-year useful life)	Cost per ton of CO2 ($) (20-year useful Life)
ABB2	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11	11,670	25.8	0	0	25.8	13.5	15.5	-2.5	19.90
ABB2	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
ABB2	Induced Draft Fans	2021	2,900	1.2	132.084	140,125	310.4	0	0	-2.0	-1,450.0	-1448.0	195.3	13.74
ABB2	Forced Draft Fans	2021	2,000	0.2	22	23,354	51.7	0	0	-2.0	-1,000.0	-998.0	135.3	56.86
ABB2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	3	25.3	26,840	59.5	0	0	59.5	8.4	10.4	-26.1	0.95
ABB2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	47	50,211	111.2	0	0	111.2	4.5	6.5	-77.9	6.61
ABB2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	66	70,018	155.1	0	0	155.1	3.2	5.2	-121.8	4.74
ABB2	Heat Rate Improvement Training	2021	15	0.3	33	35,009	77.5	0	0	77.5	0.2	2.2	-76.5	0.28
ABB2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Improved Condenser Cleaner Strategies	2021	N/A	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-18,565	-41.1	0	N/A	-41.1	-18.2	-16.2	106.0	-33.45
ABB2	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-39,146	-86.7	0	N/A	-86.7	-12.4	-10.4	149.6	-15.80
ABB2	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-66,199	-146.6	0	N/A	-146.6	-9.5	-7.5	206.9	-9.32
FBC2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	476	0.5	63	12,782	28.3	0	0	28.3	16.8	18.8	3.4	5.41
FBC2	Circulating Water Pumps	2021	900	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	60.0	N/A
FBC2	Boiler Feed Pump	2021	600	0.6	76	15,337	34.0	-2	0	32.0	18.8	20.8	8.0	5.69
FBC2	Forced Draft Fans	2021	2,000	0.5	63.195	12,781	28.3	-2	0	26.3	76.0	78.0	107.0	22.74

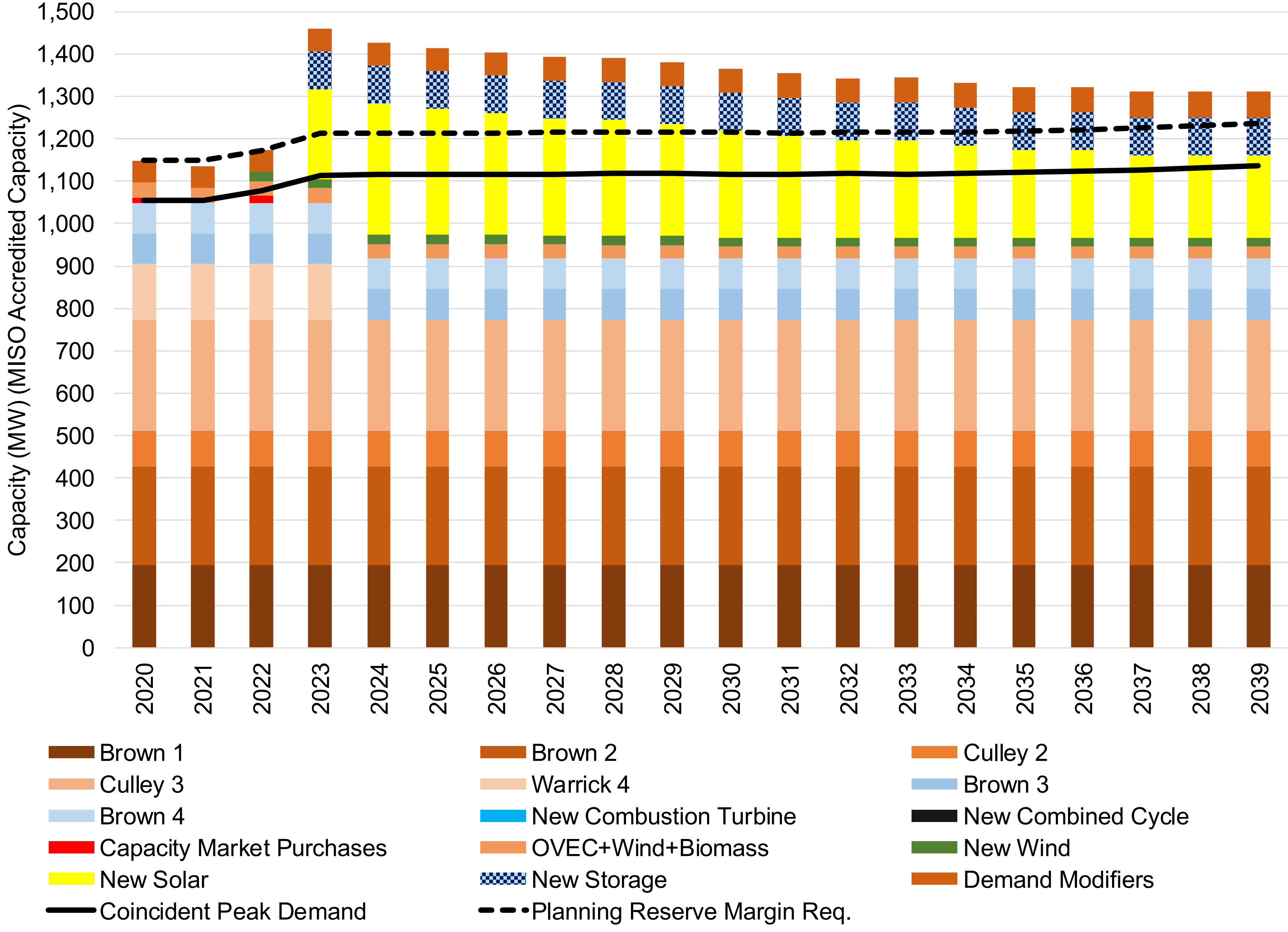
Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (20-year useful life)	Cost per ton of CO2 ($) (20-year useful Life)
FBC2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.3	33	6,654	14.7	0	0	14.7	33.9	35.9	18.6	10.94
FBC2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.47	59.4	12,014	26.6	0	0	26.6	18.8	20.8	6.7	6.05
FBC2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	78	15,856	35.1	0	0	35.1	14.2	16.2	-1.8	4.59
FBC2	Synchronized Controlled Sootblowing System	2021	350	0.1	12.64	2,556	5.7	0	0	5.7	61.8	63.8	17.7	19.90
FBC2	Heat Rate Improvement Training	2021	15	0.3	38	7,665	17.0	0	0	17.0	0.9	2.9	-16.0	0.28
FBC2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC2	Improved Condenser Cleaner Strategies	2021	N/A	0.4	53	10,740	23.8	0	0	23.8	N/A	N/A	N/A	N/A
FBC3	HP/IP Upgrades	2022	19,900	1.5	158.3	280,580	621.5	0	0	621.5	32.0	35.0	705.1	75.44
FBC3	Air Heater Basket, Seal, and Sector Plate Replacement	2022	750	0.5	53	93,586	207.3	0	0	207.3	3.6	6.6	-157.3	8.53
FBC3	Air Heater (Steam Coil) System Repairs	2022	350	0.1	10.6	18,788	41.6	0	0	41.6	8.4	11.4	-18.3	19.90
FBC3	Circulating Water Pumps	2022	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
FBC3	Forced Draft Fans	2022	2,000	0.46	48.5392	86,034	190.6	-2	0	188.6	10.6	13.6	-55.2	24.72
FBC3	Neural Network with 0.25% Reduction in Excess O_2	2022	500	0.3	26	46,793	103.7	0	0	103.7	4.8	7.8	-70.3	11.37
FBC3	Neural Network with 0.50% Reduction in Excess O_2	2022	500	0.46	48.54	86,035	190.6	0	0	190.6	2.6	5.6	-157.2	6.18

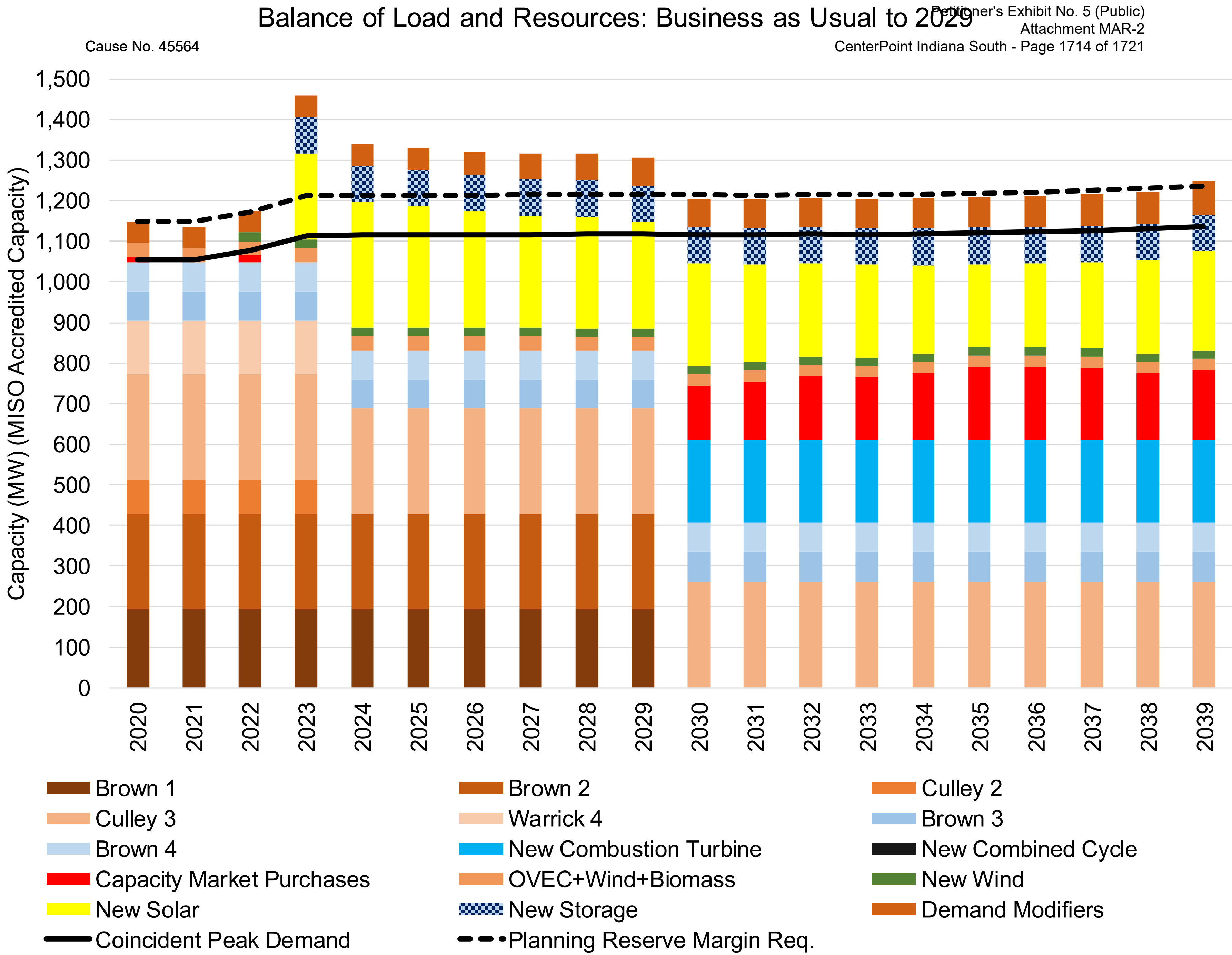
Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (20-year useful life)	Cost per ton of CO2 ($) (20-year useful Life)
FBC3	Neural Network with 0.75% Reduction in Excess O_2	2022	500	0.6	65	115,919	256.8	0	0	256.8	1.9	4.9	-223.4	4.59
FBC3	Heat Rate Improvement Training	2022	15	0.3	31.7	56,187	124.5	0	0	124.5	0.1	3.1	-123.5	0.28
FBC3	On-Site Heat Rate Appraisals	2022	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC3	Improved Condenser Cleaner Strategies	2022	N/A	0.44	46.4	82,242	182.2	0	0	182.2	N/A	N/A	N/A	N/A
FBC3	Economizer (1 Tube Pass)	2022	750	-0.1	-14	-25,169	-55.8	0	195.0	139.2	5.4	8.4	-101.7	17.53
FBC3	Economizer (2 Tube Pass)	2022	1,075	-0.28	-29.1	-51,578	-114.3	0	288.8	174.6	6.2	9.2	-120.8	23.20
FBC3	Economizer (3 Tube Pass)	2022	1,400	-0.4	-45	-79,583	-176.3	0	382.6	206.3	6.8	9.8	-136.3	29.44

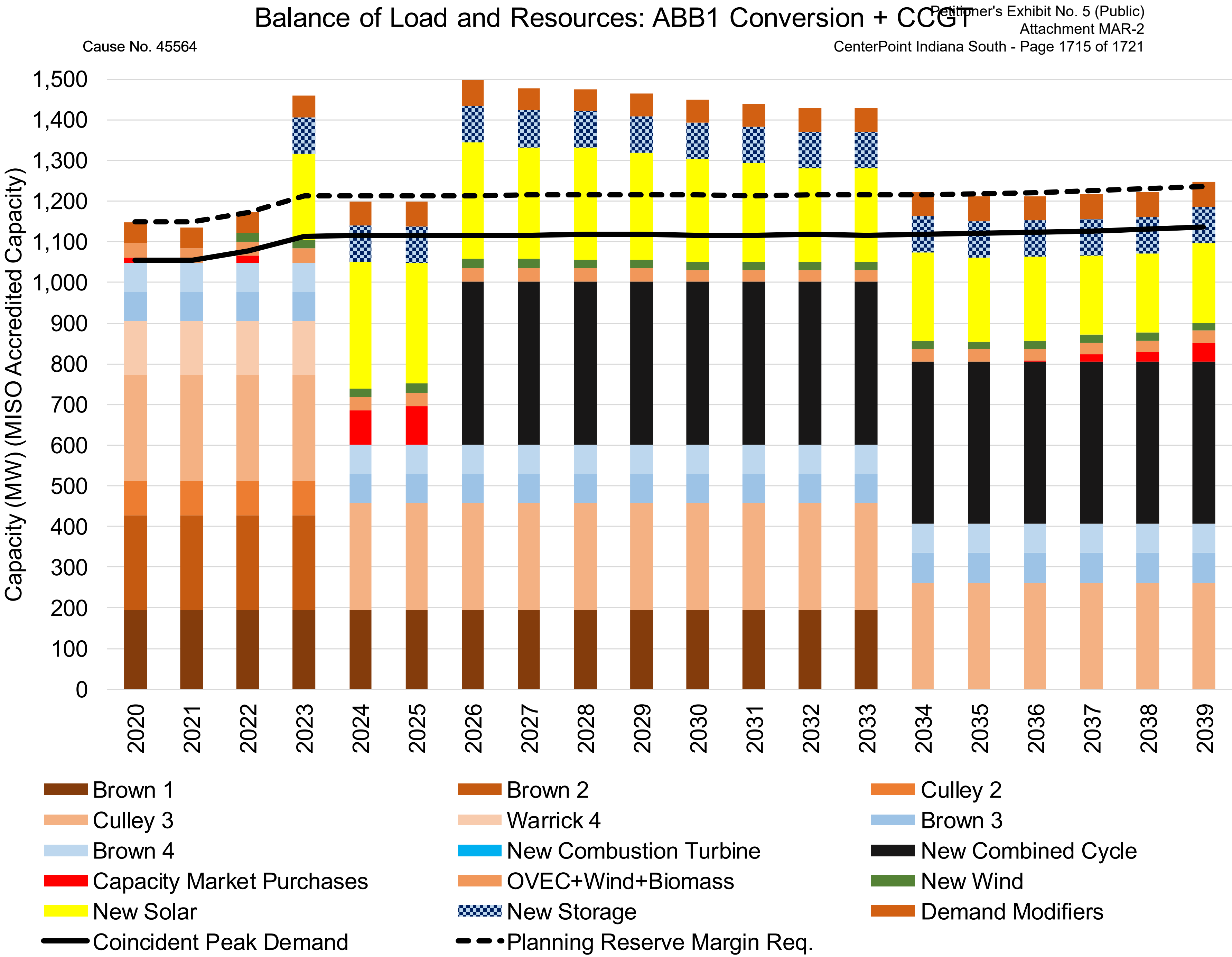
Attachment 8.1 Balance of Load and Resources


Balance of Load and Resources: Reference Case
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.

Balance of Load and Resources: Business as Usual to 2039

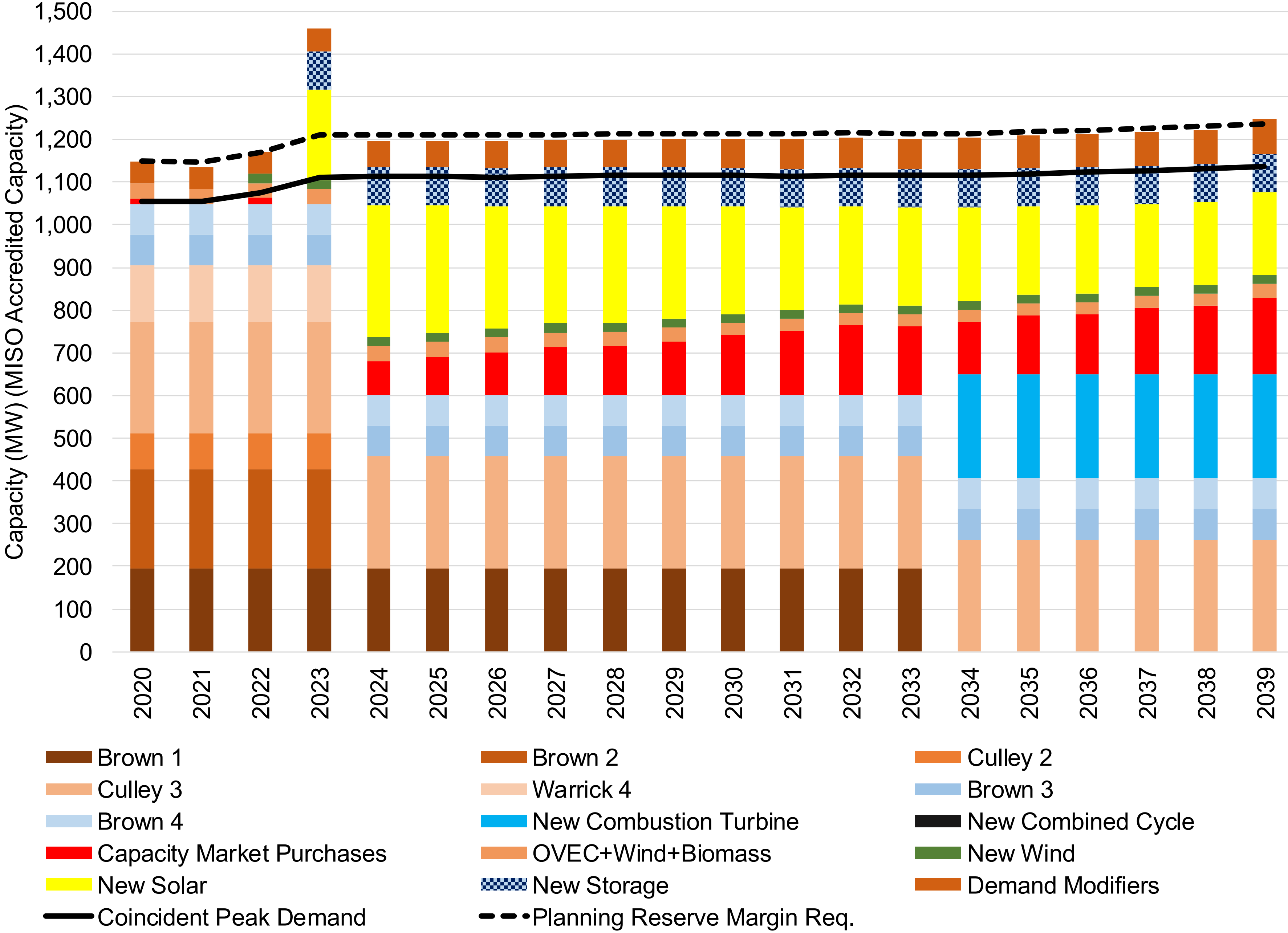



Balance of Load and Resources: Business as Usual to 2029
Capacity (MW) (MISO Accredited Capacity)
0
100
200
300
400
500
600
700
800
900
1,000
1,100
1,200
1,300
1,400
1,500
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.

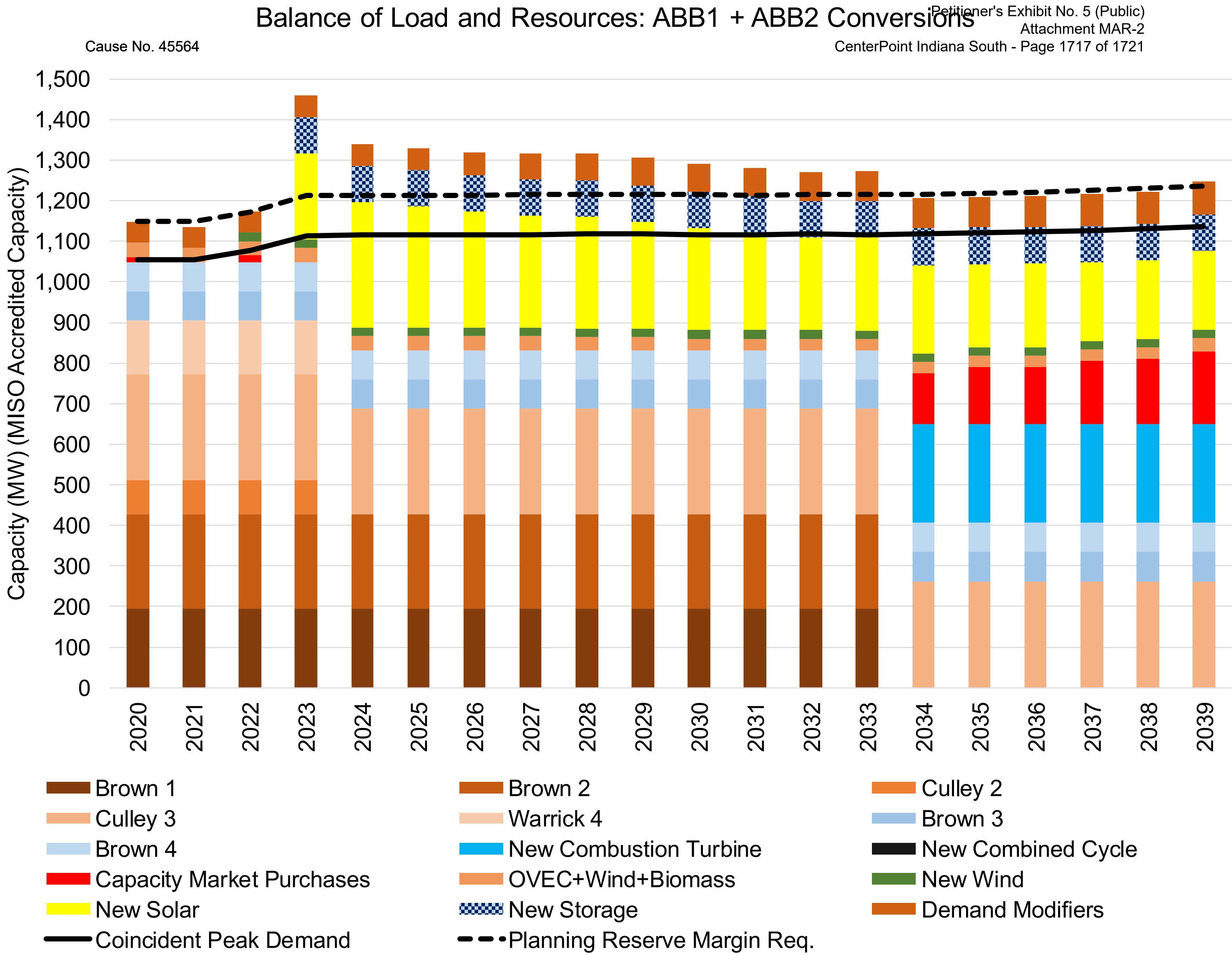

Balance of Load and Resources: ABB1 Conversion + CCGT
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.

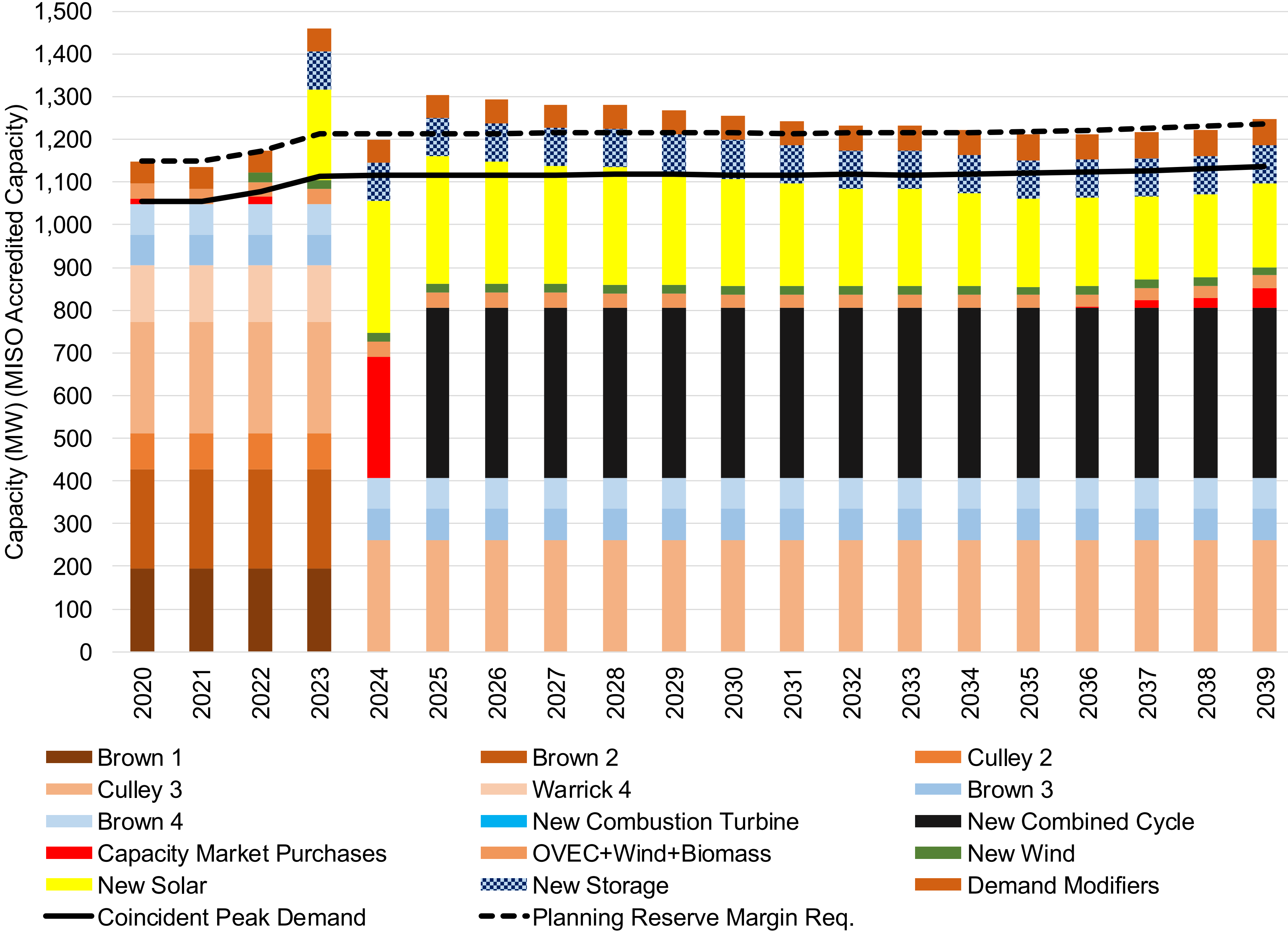
Cause No. 45564

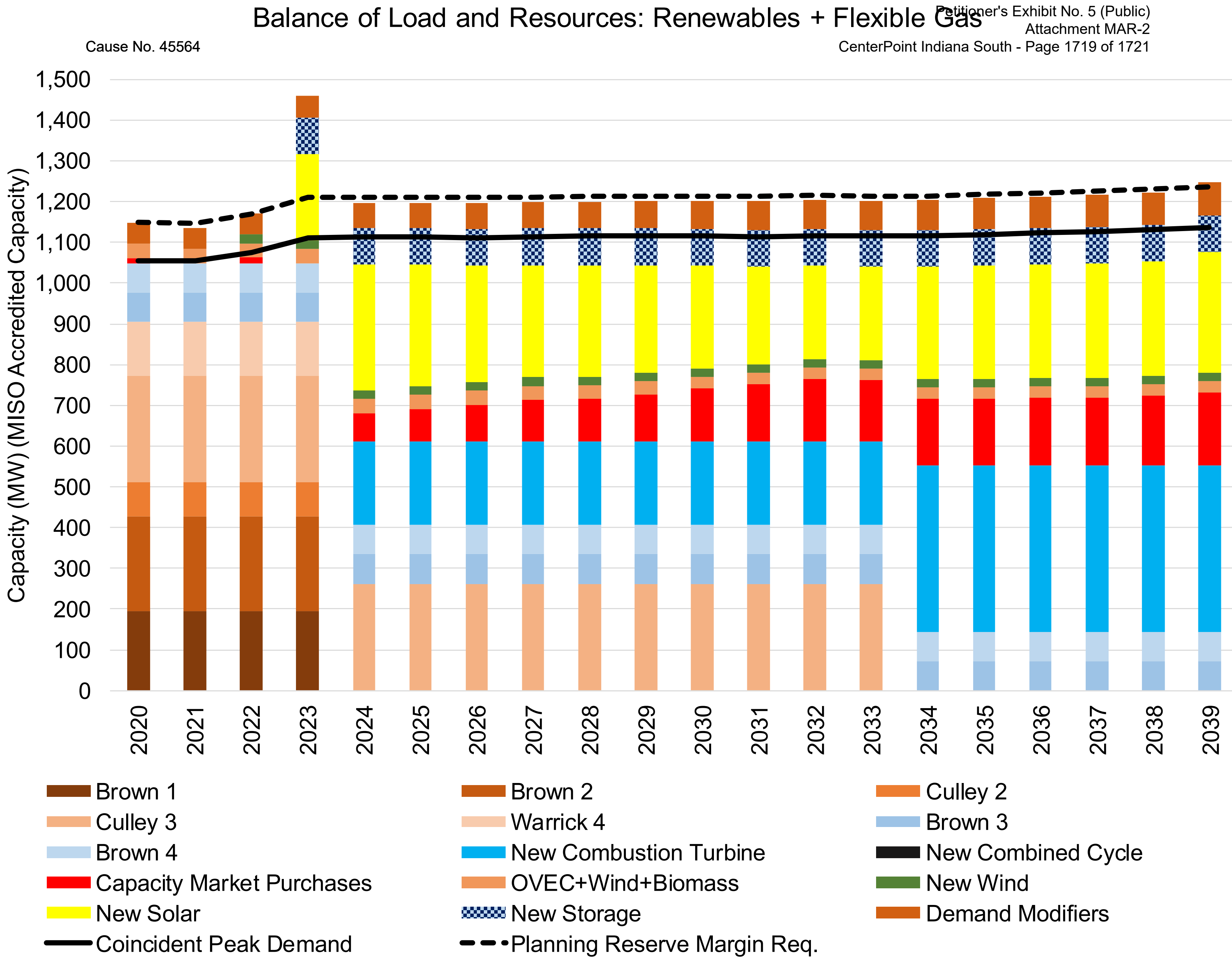
Balance of Load and Resources: ABB1 Conversion

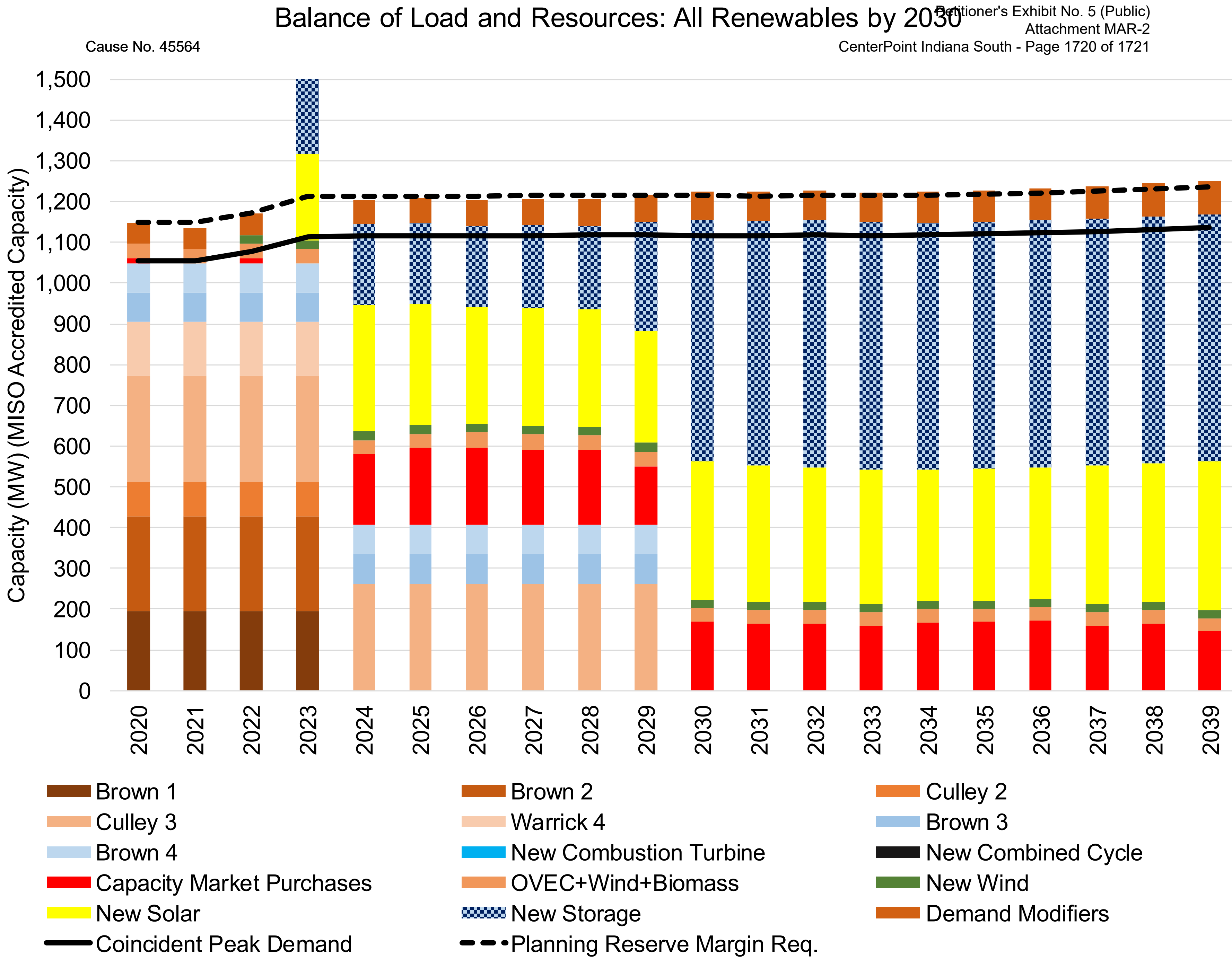


Cause No. 45564

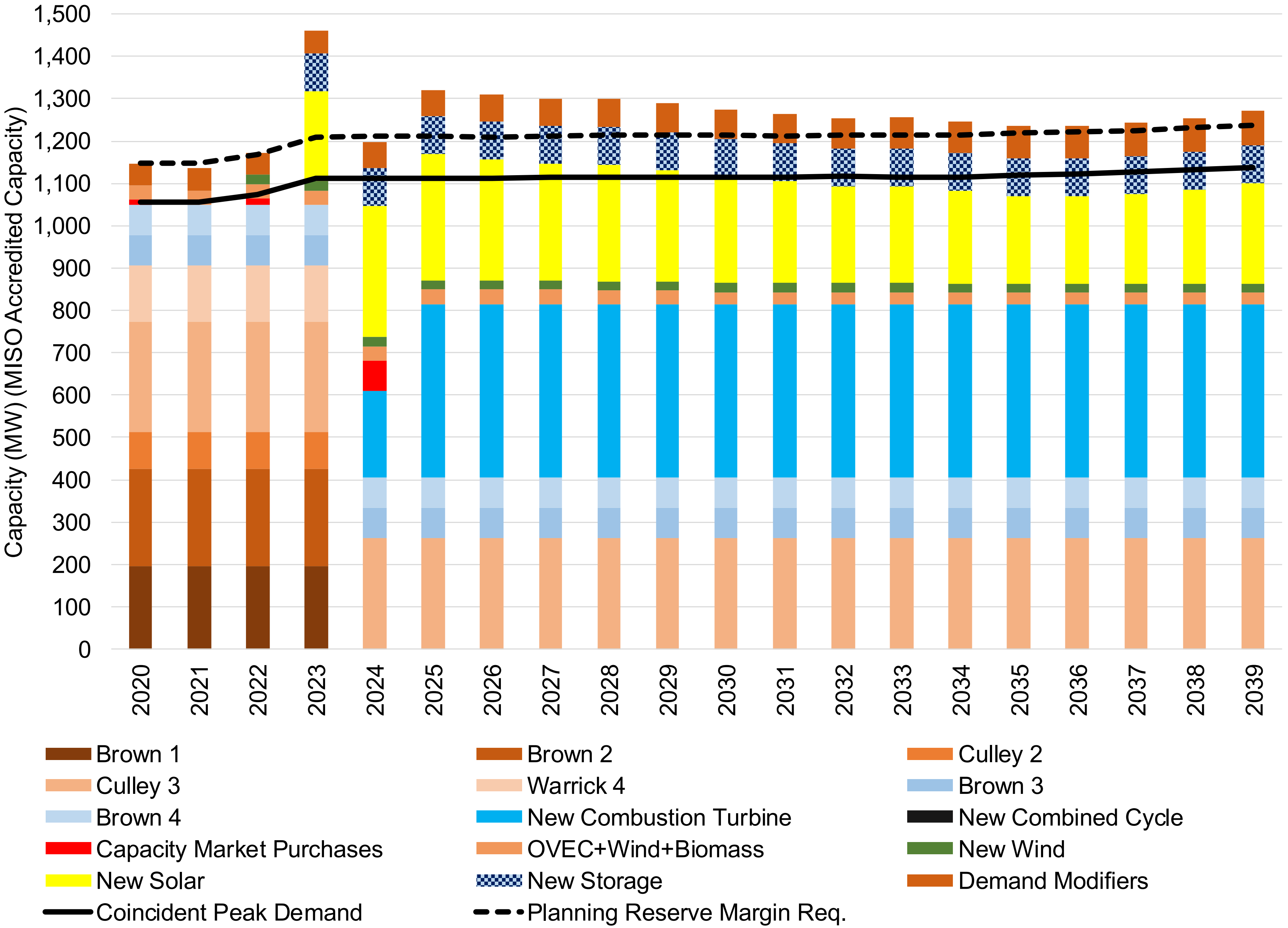



Balance of Load and Resources: Diverse Small CCGT
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.


Balance of Load and Resources: Renewables + Flexible Gas
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.


Balance of Load and Resources: All Renewables by 2030
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.

Balance of Load and Resources: High Technology (Preferred Portfolio)



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

Line	Description	Savings (Millions $)	Cost (Millions $)	Total (Millions $)
1	Expected O&M and Fuel Savings from C2, W4, ABB 1&2	($143)		
2	460 MW Combustion Turbine		$79	
3	300 MW Posey *	($5)	$37	
4	100 MW Warrick *	($2)	$10	
5	335 MW Solar PPA *	($6)	$28	
6	200 MW Wind *	($5)	$36	
7	Securitization	($68)	$23	
8	Subtotal	($229)	$213	
9	Net Cost in millions			($16)
	*REC Sale Savings			

	Day-One Monthly Bill Impact	Customers	4CP Allocations	Monthly Bill Impact 4CP
10	Residential	132,669	41%	($4)
11	Small General Service	10,118	2%	($2)
12	Demand General Service	8,204	28%	($46)
13	Off Season Service	742	2%	($39)
14	Large Power	117	26%	($3,100)
15	High Load Factor	2	1%	($6,100)

[1] Excludes temporary capacity purchases

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

Line	Description	Savings (Millions $)	Cost (Millions $)	Total (Millions $)
	Expected O&M and Fuel Savings			
1	from C2, W4, ABB 1&2	($143)		
2	460 MW Combustion Turbine		$79	
3	300 MW Posey *	($5)	$37	
4	100 MW Warrick *	($2)	$10	
5	335 MW Solar PPA *	($6)	$28	
6	130 MW Solar Owned *	($2)	$18	
7	200 MW Wind *	($5)	$36	
8	150 MW Wind *	($4)	$32	
9	Securitization	($68)	$23	
10	Subtotal	($236)	$262	
11	Net Cost in millions			$27

*REC Sale Savings

	Day-One Monthly Bill Impact	Customers	4CP Allocations	Monthly Bill Impact 4CP
12	Residential	132,669	41%	$7
13	Small General Service	10,118	2%	$4
14	Demand General Service	8,204	28%	$76
15	Off Season Service	742	2%	$65
16	Large Power	117	26%	$5,100
17	High Load Factor	2	1%	$10,000

[1] Excludes temporary capacity purchases

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

		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Line	Rate Schedule	Expected O&M and Fuel Savings from C2, W4, ABB1, and ABB2	Savings Per kWh (= A ÷ C)	2024 Budgeted Sales (kWh)	2024 Customers	Average Use Per Customer (AUPC) Per Month (kWh) (= C ÷ D ÷ 12)	Monthly C2, W4, ABB1, and ABB2 Bill Impact (= B * E * -1)	4 CP Allocations[2]	CT, Posey, & 200 MW Wind, Monthly Bill Amount (= (A9+A15+A17) * G ÷ C *E)	FAC Proxy Allocations[3] (= C ÷ C8)	Warrick & 335 MW Solar PPA Monthly Bill Amount (= (A11+A13) * I ÷ C * E)	Monthly Posey and 200 MW Wind RECs[4] (= (A10+A16) * G ÷ C * E * -1)	Monthly Warrick and 335 MW Solar PPA RECs[4] (=(A12+A14) * I ÷ C * E * -1)	Net Securitization Savings Estimate =(A18-A19)*(A ÷ A8)*-1	Securitization Estimate Monthly Bill Impact (=M ÷ C * E)	Monthly Net Bill Impact (= F + H + J + K + L + N)	Net Rate Impact ($ per kWh) (= O ÷ E)	Reference
1	Residential	$65,863,199	$ 0.04811	1,369,139,663	132,669	860	$ (41.37)	40.7467%	$ 38.75	26.4497%	$ 6.31	$ (4.71)	$ (1.27)	$ (20,662,999.22)	$ (12.98)	$ (15.27)	$(0.018)	
2	Small General Service	$2,774,336	$ 0.04270	64,974,487	10,118	535	$ (22.85)	1.8234%	$ 22.74	1.2552%	$ 3.93	$ (2.77)	$ (0.79)	$ (870,381.53)	$ (7.17)	$ (6.91)	$(0.013)	
3	Demand General Service	$43,183,320	$ 0.04100	1,053,191,507	8,204	10,698	$ (438.64)	27.9043%	$ 429.11	20.3461%	$ 78.55	$ (52.20)	$ (15.74)	$ (13,547,731.26)	$ (137.61)	$ (136.54)	$(0.013)	
4	Off Season Service	$3,380,058	$ 0.03768	89,713,357	742	10,076	$ (379.61)	2.1556%	$ 366.51	1.7331%	$ 73.98	$ (44.59)	$ (14.82)	$ (1,060,412.16)	$ (119.09)	$ (117.62)	$(0.012)	
5	Large Power	$25,785,754	$ 0.01157	2,228,821,103	117	1,587,479	$ (18,365.92)	26.4753%	$ 28,547.99	43.0575%	$ 11,655.87	$ (3,472.91)	$ (2,335.10)	$ (8,089,662.11)	$ (5,761.87)	$ 10,268.06	$ 0.006	
6	High Load Factor	$1,538,842	$ 0.00440	349,449,882	2	14,560,412	$ (64,118.41)	0.8947%	$ 56,437.52	6.7508%	$ 106,908.00	$ (6,865.71)	$ (21,417.60)	$ (482,774.73)	$ (20,115.61)	$ 50,828.18	$ 0.003	
7	Street Lighting	$0	$ -	21,096,985	42	41,859	$ -	0.0000%	$ -	0.4076%	$ 307.35	$ -	$ (61.57)	$ -		$ 245.77	$ 0.006	
8	Total	$142,525,510		5,176,386,984	151,894													
9	Posey Year 1 Estimated Cost	$ 37,172,210																Posey Solar, Line 6
10	Posey Year 1 Estimated REC Sales	$ 5,476,752																Posey Solar, Line 3 * 8 ÷ 1,000
11	Warrick Year 1 Estimated Cost	$ 9,702,116																Warrick County Solar, Line 8
12	Warrick Year 1 Estimated REC Sales	$ 1,744,992																Warrick County Solar, Line 3 * 8 ÷ 1,000
13	New Solar PPA Year 1 Estimated Cost	$ 28,304,855																335 MW Solar PPA Estimate, Line 8
14	New Solar Year 1 Estimated REC Sales	$ 5,869,200																335 MW Solar PPA Estimate, Line 3 * 8 ÷ 1,000
15	200 MW Wind Year 1 Estimated Cost	$ 35,713,256																200 MW Wind Estimate, Line 14
16	Wind Year 1 Estimated REC Sales	$ 5,326,080																200 MW Wind Estimate, Line 11 * 8
17	CTs Year 1 Estimated Cost	$ 78,506,112																CT Estimate, Line 13
18	Existing Return On and Depreciation Expense Removal	$ 68,208,792																Summary, Line 13
19	Securitization Cost	$ 23,494,831																Confidential Securitization, Line 213
20	Bill DECREASE (Line 8-9+10-11+12-13+14-15+16-17+18-19)	$ (16,257,945)																

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

Cause No. 45564

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

Line	Rate Schedule	A Expected O&M and Fuel Savings from C2, W4, ABB1, and ABB2	B Savings Per kWh (= A ÷ C)	C 2024 Budgeted Sales (kWh)	D 2024 Customers	E Average Use Per Customer (AUPC) Per Month (kWh) (= C ÷ D ÷ 12)	F Monthly C2, W4, ABB1, and ABB2 Bill Impact (= B * E * -1)	G 4 CP Allocations[2]	H CT, Posey, 200 MW Wind, 150 MW Wind, and 130 MW Owned Solar Monthly Bill Amount (= (A9+A15+A17+A18) * G ÷ C *E)	I FAC Proxy Allocations[3] (= C ÷ C8)	J Warrick & 335 MW Solar PPA Monthly Bill Amount (= (A11+A13) * I ÷ C * E)	K Monthly Posey and Wind RECs[4] (= (A10+A16+A21) * G ÷ C * E * -1)	L Monthly Warrick and New Solar RECs[4] (=(A12+A14) * I ÷ C * E * -1)	M Net Securitization Savings Estimate =(A22-A23)*(A ÷ A8)*-1	N Securitization Estimate Monthly Bill Impact =(M÷ C)*E	O Monthly Net Bill Impact (= F + H + J + K + L + N)	P Net Rate Impact ($ per kWh) (= O ÷ E)	Q Reference
1	Residential	$65,863,199	$ 0.04811	1,369,139,663	132,669	860	$ (41.37)	40.7467%	$ 51.41	26.4497%	$ 6.31	$ (4.40)	$ (1.27)	$(20,662,999.22)	$ (12.98)	$ (2.28)	$(0.003)	
2	Small General Service	$2,774,336	$ 0.04270	64,974,487	10,118	535	$ (22.85)	1.8234%	$ 30.17	1.2552%	$ 3.93	$ (2.58)	$ (0.79)	$ (870,381.53)	$ (7.17)	$ 0.71	$ 0.001	
3	Demand General Service	$43,183,320	$ 0.04100	1,053,191,507	8,204	10,698	$ (438.64)	27.9043%	$ 569.37	20.3461%	$ 78.55	$ (48.69)	$ (15.74)	$(13,547,731.26)	$ (137.61)	$ 7.24	$ 0.001	
4	Off Season Service	$3,380,058	$ 0.03768	89,713,357	742	10,076	$ (379.61)	2.1556%	$ 486.31	1.7331%	$ 73.98	$ (41.59)	$ (14.82)	$ (1,060,412.16)	$ (119.09)	$ 5.18	$ 0.001	
5	Large Power	$25,785,754	$ 0.01157	2,228,821,103	117	1,587,479	$(18,365.92)	26.4753%	$ 37,879.61	43.0575%	$ 11,655.87	$ (3,239.42)	$ (2,335.10)	$ (8,089,662.11)	$ (5,761.87)	$19,833.17	$ 0.012	
6	High Load Factor	$1,538,842	$ 0.00440	349,449,882	2	14,560,412	$(64,118.41)	0.8947%	$ 74,885.53	6.7508%	$ 106,908.00	$ (6,404.13)	$ (21,417.60)	$ (482,774.73)	$ (20,115.61)	$69,737.77	$ 0.005	
7	Street Lighting	$0	$ -	21,096,985	42	41,859	$ -	0.0000%	$ -	0.4076%	$ 307.35	$ -	$ (61.57)	$ -		$ 245.77	$ 0.006	
8	Total	$142,525,510		5,176,386,984	151,894													
9	Posey Year 1 Estimated Cost	$ 37,172,210																Posey Solar, Line 6
10	Posey Year 1 Estimated REC Sales	$ 5,476,752																Posey Solar, Line 3 * 8 ÷ 1,000
11	Warrick Year 1 Estimated Cost	$ 9,702,116																Warrick County Solar, Line 8
12	Warrick Year 1 Estimated REC Sales	$ 1,744,992																Warrick County Solar, Line 3 * 8 ÷ 1,000
13	New Solar PPA Year 1 Estimated Cost	$ 28,304,855																335 MW Solar PPA Estimate, Line 8
14	New Solar Year 1 Estimated REC Sales	$ 5,869,200																335 MW Solar PPA Estimate, Line 3 * 8 ÷ 1,000
15	200 MW Wind Year 1 Estimated Cost	$ 35,713,256																200 MW Wind Estimate, Line 14
16	200 MW Wind Year 1 Estimated REC Sales	$ 5,326,080																200 MW Wind Estimate, Line 11 * 8
17	CTs Year 1 Estimated Cost	$ 78,506,112																CT Estimate, Line 13
18	130 MW Owned Solar Year 1 Estimated Cost	$ 17,523,165																130 MW Owned Solar Estimate, Line 6
19	130 MW Owned Solar Year 1 Estimated REC Sales	$ 2,381,459																130 MW Owned Solar Estimate, Line 3 * 8 ÷ 1,000
20	150 MW Wind Year 1 Estimated Cost	$ 31,962,952																150 MW Wind Estimate, Line 14
21	150 Wind Year 1 Estimated REC Sales	$ 3,994,560																150 MW Wind 1 Estimate, Line 11 * 8 ÷ 1,000
22	Existing Return On and Depreciation Expense Removal	$ 68,208,792																Summary, Line 13
23	Securitization Cost	$ 23,494,831																Confidential Securitization, Line 213
24	Bill INCREASE (Line 8-9+10-11+12-13+14-15+16-17+18-19)	$ 26,852,153																

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

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY dba CENTERPOINT ENERGY INDIANA SOUTH

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

Line	Description		Estimated Bill Impact
1	Residential Sales - kWh		1,369,139,663
2	Residential Allocation (Capital)		40.6160%
3	Standard Residential AUPC		1,000
4	Actual AUPC		860
5	Gross Plant Investment	$	323,000,000
6	Pre-Tax Rate of Return		7.53%
7	Pre-Tax Return on Investment (Line 5 x Line 6)	$	24,321,900
8	Depreciation Rate		3.44%
9	Annual Depreciation Expense (Line 5 x Line 8)	$	11,111,200
10	Other Annual O&M Expense - Fixed and Variable[1]	$	5,622,125
11	Cost of Gas[2]	$	8,988,996
12	Cost of Firm Gas Service	$	27,300,000
13	Annual Revenue Requirement with IURT (Sum of Lines 7, 9, 10, 11, & 12 ÷ .9852)	$	78,506,112
14	Residential Rate per kWh (Line 14 x Line 12 ÷ Line 1)	$	0.023289
15	Residential Bill (Standard AUPC assumption 1,000 kWh)	$	23.29
16	Residential Bill (Actual AUPC 860 KWh)	$	20.03

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

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

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY dba CENTERPOINT ENERGY INDIANA SOUTH

BAU 2029 - Continue ABB1 & ABB2 Project
Estimated Year 1 Impact
on the Bill of a Residential Standard Customer

Line	Description		Estimated Bill Impact
1	Residential Sales - kWh		1,369,139,663
2	Residential Allocation (Capital)		40.6160%
3	Standard Residential AUPC		1,000
4	Actual AUPC		860
5	Gross Plant Investment	$	309,990,000
6	Pre-Tax Rate of Return		6.10%
7	Pre-Tax Return on Investment (Line 5 x Line 6)	$	18,909,390
8	Depreciation Rate		3.50%
9	Annual Depreciation Expense (Line 5 x Line 8)	$	10,849,650
10	Annual O&M Expense - Fixed and Variable	$	57,102,889
11	Cost of Coal	$	46,855,668
12	Annual Revenue Requirement with IURT (Sum of Lines 7, 9, 10, & 11 ÷ .9852)	$	135,726,346
13	Residential Rate per kWh (Line 14 x Line 12 ÷ Line 1)	$	0.040264
14	Residential Bill (Standard AUPC assumption 1,000 kWh) (Line 13 x Line 3)	$	40.26
15	Residential Bill (Actual AUPC 860 KWh) (Line 13 x Line 4)	$	34.63

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY dba CENTERPOINT ENERGY INDIANA SOUTH

Conversion of ABB1 & ABB2 Coal to Gas Project
Estimated Year 1 Impact
on the Bill of a Residential Standard Customer

Line	Description		Estimated Bill Impact
1	Residential Sales - kWh		1,369,139,663
2	Residential Allocation (Capital)		40.6160%
3	Standard Residential AUPC		1,000
4	Actual AUPC		860
5	Gross Plant Investment	$	165,660,000
6	Pre-Tax Rate of Return		6.10%
7	Pre-Tax Return on Investment (Line 5 x Line 6)	$	10,105,260
8	Depreciation Rate		3.50%
9	Annual Depreciation Expense (Line 5 x Line 8)	$	5,798,100
10	Annual O&M Expense - Fixed and Variable[1]	$	55,947,563
11	Cost of Gas[2]	$	14,377,357
12	Annual Revenue Requirement (Sum of Lines 7, 9, 10 & 11)	$	87,523,629
13	Residential Rate per kWh (Line 14 x Line 12 ÷ Line 1)	$	0.025964
14	Residential Bill (Standard AUPC assumption 1,000 kWh) (Line 13 x Line 3)	$	25.96
15	Residential Bill (Actual AUPC 860 KWh) (Line 13 x Line 4)	$	22.33

[1] Includes annual firm gas service cost

[2] Based on IRP assumptions

Cause No. 45564

2018 Report on the

Statewide Analysis of Future Resource Requirements for Electricity

Indiana Utility Regulatory Commission Staff

Cause No. 45564

Table of Contents

Cause No. 45564

Cause No. 45564

I. Introduction and Executive Summary

The 2018 Report (Report) on the Statewide Analysis of Future Resource Requirements for Electricity (Statewide Analysis) was prepared by Indiana Utility Regulatory Commission (IURC or Commission) staff, as delegated by the Commission, for the Governor and Indiana General Assembly. Consistent with the statutory requirements of Indiana Code § 8-1-8.5-3, Commission staff developed the Report by reviewing information provided in the Indiana electric utilities' Integrated Resource Plans from 2015 to 2017, the State Utility Forecasting Group's 2017 Forecast, and other sources in order to summarize and consolidate this information outlining the present condition landscape for all utilities and their stakeholders . Information provided from the State Utility Forecasting Group (SUFG) included results from its recent modeling update funded by the Commission.

Reports regarding the Statewide Analysis are required to be submitted each year according to Ind. Code § 8-1-8.5-3(h). In previous years, the Commission has relied on the reports and forecasts of the SUFG. The 2018 Report is the first one prepared by Commission staff. It is important to note that the Statewide Analysis is not to be construed as a statewide energy plan and does not set policy. In addition, the Statewide Analysis does not determine or predetermine individual electric utility resource decisions or Commission findings and conclusions in any pending or future proceeding before the Commission. The Statewide Analysis is intended to provide information and analysis for consideration by the Governor and the Indiana General Assembly, as well as consideration by the Commission, Indiana electric utilities, and interested stakeholders.

Indiana's electric utilities are required to provide safe and reliable service in an efficient and cost-effective manner. An Integrated Resource Plan (IRP) is a plan submitted by an electric utility to the Commission,[1] and it assists the utility in making sure it has the necessary resources to fulfill this obligation. The plan the utility submits looks forward over the next 20 years, forecasts the types and quantity of generation that the utility will need to reliably provide electricity to its customers, and evaluates resource options on both a short-term and long-term basis to meet those future electricity requirements.

Based on Commission staff review, Indiana's electricity needs will increase between 0.1 percent and 1.12 percent each year over the next 20 years. Electricity demand has shown very low projected growth rates. In the last decade, growth in electricity demand has typically been less than two percent per year. More recently, growth rates of around one percent (or even negative for some utilities) have been common.

Taking into account plant retirements, the SUFG projected generation and/or other resources required to meet Indiana's future needs are: 3,600 megawatts (MW) by 2025, 6,300 MW by 2030, and 9,300 MW by 2035. The utilities project adding combinations of natural gas, wind,

[1] IRPs are discussed in more detail on page 3. IRPs are submitted by Indiana's eight largest electric utilities on a staggered three year cycle. IRPs are intended to comprehensively evaluate a broad range of feasible and economically viable resource alternatives over at least a 20 year planning period to assure electric power will be delivered to their customers at the lowest cost reasonably possible while providing safe and reliable service.

Cause No. 45564

solar, biomass, and hydroelectric generation, as well as maintaining and improving energy efficiency and demand response programs. Generally, the utilities make their resource decisions based on the comparative costs of these resources.

II. Background

A. Overview of Statutory Requirements

This analysis of future electric resource requirements is being provided to the Governor and the Indiana General Assembly pursuant to Ind. Code § 8-1-8.5-3. In 2014, the Commission provided its recommendations in a letter to the Governor that concerned, in part, the need for generation resources in the near and long term and how energy efficiency and demand side management can help reduce that need. The Commission's recommendations focused on the importance of IRPs, in which electric utilities assess their customers' energy needs and the generation resources to meet those needs under a variety of circumstances, in both the short (3-5 years) and long term (20 years or more). In 2015, Senate Enrolled Act (SEA) 412 codified the requirement that utilities submit IRPs, as well as energy efficiency plans, and amended Ind. Code § 8-1-8.5-3 to clarify the analysis to be performed by the Commission regarding future resource requirements for electricity.

In 2015, the Commission opened a new round of stakeholder meetings to modernize and update its IRP rule, and the Commission provided additional funding to the SUFG to update modeling software for more robust forecasts. Since 2014, the electric utilities have submitted IRPs in accordance with the additional requirements in the Commission's draft IRP proposed rules. In December 2017, SUFG issued its "Indiana Electricity Projections: The 2017 Forecast," using its new modeling software. The Commission's updated IRP and energy efficiency rules are expected to be fully promulgated and in effect before the end of the 2018 calendar year.

On April 11, 2018, the Commission issued a General Administrative Order (GAO), GAO 2018-2, delegating the authority to perform this annual analysis to Commission staff. GAO 2018-2 also set forth the approximate timelines and procedures for an open, transparent process to receive comments and hold a public hearing on a draft analysis, prior to the completion and submission of the final analysis each year.

Ind. Code § 8-1-8.5-3(a) states that this analysis must include an estimate of the following:

(1) The probable future growth of the use of electricity;
(2) The probable needed generating reserves;
(3) The optimal extent, size, mix, and general location of generating plants:
(4) The optimal arrangements for statewide or regional pooling of power and arrangements with other utilities and energy suppliers to achieve maximum efficiencies for the benefit of the people of Indiana; and
(5) The comparative costs of meeting future growth by other means of providing reliable, efficient, and economic electric service, including purchase of power, joint ownership

Cause No. 45564

of facilities, refurbishment of existing facilities, conservation (including energy efficiency), load management, distributed generation, and cogeneration.

In preparing this analysis, and through the Commission's regular involvement in regional and federal energy issues, Commission staff utilized information from the utilities' IRPs, the Midcontinent Independent System Operator (MISO), the PJM Interconnection, LLC (PJM), the Federal Energy Regulatory Commission (FERC), and the U.S. Energy Information Administration (EIA).

B. Integrated Resource Plans

1. What is an Integrated Resource Plan?

Indiana's electric utilities are required to supply power at the lowest reasonable cost while providing safe and reliable service. The integrated resource planning process results in a range of resource portfolios and a preferred plan submitted by each electric utility on a staggered three year cycle to the Commission. The IRP assists the utility in its resource planning, making sure it has the necessary resources to fulfill future obligations. The IRP looks forward over at least the next 20 years to estimate the amount of resources the utility will need to reliably provide electricity to its customers, and evaluates resource alternatives on both a short-term and long-term basis to meet those future electricity requirements on a reliable and economic basis.

2. IRP History and Evolution

During the 1970s and early 1980s, Indiana's utilities, like utilities throughout the United States, built enormous amounts of generating capacity to meet the expected burgeoning demand for more electricity. Unfortunately, the utilities' forecasts were overly optimistic, which resulted in the construction of excessive generating capacity. The excess capacity, in turn, led to rapidly escalating electric rates for customers in Indiana and across the country. Prudence investigations became common-place, which resulted in financial stress on electric utilities. Several electric utilities across the country went into default and, in extreme cases, bankruptcy. This era, and the ramifications of rapidly escalating costs, was transformational for the electric utility industry and for utility regulation, including the widespread adoption of IRP processes and added emphasis on energy efficiency and demand response (collectively referred to as "Demand-Side Management"). Demand response is the reduction in electricity usage for limited periods of time, such as during peak electricity usage or emergency conditions

In 1983, the Indiana General Assembly responded by enacting Ind. Code chapter 8-1-8.5, which established the need for planning and the requirement that utilities petition the Commission for approval of new electric generation facilities prior to their construction, lease, or purchase. A "certificate of public convenience and necessity" (CPCN) is now required and can only be issued by the Commission upon specific findings, including that the proposed additional capacity is necessary and consistent with planning. In 1985, this chapter was amended to establish the SUFG to provide an independent forecast and analysis of future electricity requirements.

Cause No. 45564

In 1995, the Commission promulgated the Integrated Resource Plan Rule (IRP Rule), located in the Indiana Administrative Code at 170 IAC 4-7, which established the requirement that certain electric utilities in Indiana submit an IRP to the Commission every two years. The IRP Rule also set out in great detail what should be included in a utility's IRP. The following utilities were (and are) required to submit IRPs:

- Duke Energy Indiana (Duke)
- Hoosier Energy
- Indianapolis Power & Light Company (IPL)
- Indiana Michigan Power Company (I&M)
- Indiana Municipal Power Agency (IMPA)
- Northern Indiana Power Service Company (NIPSCO)
- Southern Indiana Gas & Electric Company (SIGECO)
- Wabash Valley Power Association (Wabash Valley)

Much has changed in the electric industry since 1995, specifically resource planning. Integrated resource planning has become increasingly sophisticated over the years with new computer modeling and other technologies. In 2001, FERC approved MISO and PJM as regional transmission operators (RTO). Together, these two RTOs cover the entire State of Indiana. The RTOs control the transmission of electricity at the bulk transmission or wholesale level, in contrast to the Indiana utilities who control the distribution or retail level of electricity delivery. Because of the existence of RTOs, some aspects of Indiana utilities' IRPs are no longer performed by the utilities. For instance, although the transmission grid is now operated by the RTOs, the 1995 IRP rule, which is still in effect, assumed the utilities maintained operational control of their own transmission system.

As a result of these changes at the regional and federal level, the Commission started an investigation in 2009 (IURC Cause No. 43643) to assess the need to reformulate the IRP Rule, taking the modern day grid context into account. In an order issued October 14, 2010, the Commission determined the need existed to update the 1995 IRP rule. Commission staff performed extensive research and facilitated an inclusive stakeholder process. That process resulted in a proposed IRP rule in 2012. The 2012 proposed rule was not officially promulgated due in part to the rulemaking moratorium, Indiana Executive Order 13-03. Nevertheless, starting with the IRPs that were due in 2013, utilities voluntarily agreed to follow the 2012 draft proposed rule requirements, including:

- A public advisory process to educate and seek input from customers and other interested stakeholders;
- Contemporary Issues Technical Conference, sponsored annually by Commission staff, to provide information on new technologies, computer models, and planning methods;
- Using information reported to and from the relevant RTOs;
- Upgrades to modeling risk and uncertainty; and
- A report on each utility's IRP by the director designated by the Commission (currently the Director of the Research, Policy, and Planning Division).

Following the passage of SEA 412 in 2015, Commission staff again facilitated an inclusive stakeholder process to further update the 2012 draft proposed rule. After numerous public

Cause No. 45564

meetings and rounds of comments in which stakeholders participated, the Commission developed another proposed rule. The utilities began voluntarily complying with this updated proposed rule in their 2016 IRPs, including:

- Remodeling the procedural schedule for the submission of IRPs and energy efficiency plans so the filings are now made every three years;
- Removing obsolete requirements;
- Adding a checklist specifying all the required content in the integrated resource plans and energy efficiency plans;
- Updating the transparent stakeholder processes utilities must use to allow stakeholder and public input into the development of the plans; and
- Reframing the resource selection criteria to better reflect modern forecasting models and the modern electricity market.

The most-recent proposed IRP rule (IURC RM #15-06; LSA #18-127) was granted an exception to the rulemaking moratorium by the Office of Management and Budget on February 12, 2018. The Notice of Intent to Adopt a Rule was published in the Indiana Register on March 14, 2018, and on May 25, 2018, the State Budget Agency approved the fiscal impact of this rulemaking. The rulemaking is expected to be completed, and the updated IRP Rule fully promulgated, before the end of 2018. Information regarding this rulemaking can be found on the Commission's website at: https://www.in.gov/iurc/2842.htm.

3. IRP Contents (2015 – 2017)

The fundamental building blocks of an IRP include researching customer electricity needs (i.e. load research), forecasting future electricity needs (i.e., load forecasting) over a number of circumstances or scenarios, assessing existing generation resources, and systematically considering all forms of resources needed to satisfy short-term and long-term (at least 20 years) requirements under the various scenarios. Increasingly, IRPs include planning for generation, transmission, and the distribution system. IRPs assess various risks and their ramifications. It is important to note that the IRP process typically takes more than one year to complete. In addition to developing appropriate data inputs, inputting the data into the planning models, and conducting the necessary analysis, the stakeholder engagement process entails a significant time commitment. The Commission considers a robust stakeholder process essential to understanding and expediting cases by narrowing a number of contentious issues.

Long-term resource planning starts with a forecast of customers' electricity needs well into the future. Planning the lowest cost resources to provide reliable service over that time horizon is the objective of IRPs. Most states, including Indiana, that review utilities' IRPs require a 20-year load forecast and resource planning horizon. The length of the planning horizon is to better ensure that the planning analysis objectively considers all resources.

A key consideration in long-term resource planning is the need to retain maximum flexibility in utility resource decisions to minimize risks. An IRP developed by a utility should be regarded as illustrative and not a commitment for the utility to undertake. Essentially, IRPs are a snapshot in time based on the best available information.

Cause No. 45564

Perhaps the greatest benefit of an IRP is that it can provide utilities with an objective and comprehensive assessment of the potential risks and costs associated with forecasting customer needs and the requisite resources to meet those needs. The risk and uncertainties facing Indiana utilities, like other utilities throughout the nation, may be more significant than at any other time in the industry's history with the possible exception of the Great Depression and the energy crisis of the 1970s and 1980s. The most obvious risk confronting Indiana utilities, and utilities nationwide, involves the economics of retiring existing facilities and the economic choice of alternative resources to replace retired generating resources. Since perfect prescience is not possible, utilities have a variety of risk factors to consider, such as:

- Short and long-term projections for the comparative costs of fuels;
- Short and long-term projections for market purchases;
- The range of potential costs for renewable resources;
- The potential for future technologies (e.g., increased efficiencies of renewable resource, energy efficiency, battery storage, distributed energy, continued improvements to combined cycle capabilities, microgrids, fuel cells, future nuclear, coal) to be transformational (such as electrification of transportation); and
- Whether load forecasts are unduly optimistic or pessimistic, among other factors.

Integrated resource planning considers all resources. In addition to traditional resources such as coal, natural gas, and nuclear, an effective IRP also objectively considers energy efficiency, demand response, wind, solar, customer-owned generation resources including combined heat and power and battery storage, as well as the abilities of the transmission system. These many and varying resources are studied on a comparable basis as reasonably possible to give greater assurance that the portfolios of resources considered and selected by the utilities are sufficiently robust and flexible to allow for alterations as conditions warrant.

4. Limitations of this Report

This report summarizes the most recent utility IRPs projecting possible future load growth and resource needs over the 20-year planning horizon. Each utility-specific IRP describes the process used to determine what the utility believes is the best mix of generation, distributed energy resources, and energy efficiency resources to meet their customers' needs for reliable, low-cost, and environmentally acceptable power over the next 20 years. Taken together, the IRPs allow the Commission to better understand how the utilities, both individually and as a group, see the general direction for future load growth needs and resource options. However, as a precaution, because each year only about one-third of the utilities submit an IRP due to the new three-year cycle, it is difficult to compare one utility's IRP analysis and results in 2015 with another utility's resource analysis in 2017. Four years ago, for example, utilities were planning for the Clean Power Plan. Natural gas price projections due to fracking seemed to solidify more than expected by experts. Some utilities lost significant loads. It must also be noted that each utility in the development of its IRP uses different methodologies, computer models, and data inputs and assumptions, so any comparisons of utility IRPs, even those prepared within the same year, must keep these considerations in mind.

This report includes not only the utilities' IRPs, but also analysis by the SUFG, the RTOs, and a national perspective. Similar qualifications must be kept in mind when comparing long-term

Cause No. 45564

resource planning analysis prepared by these organizations with each other and Indiana electric utilities.

Even though Indiana utilities over the last several years have significantly improved their IRP methodologies, data, risk and uncertainty analysis, and the presentation of their written reports, there is still considerable disagreement among various stakeholders as to all aspects of IRP development and presentation of the results. The flavor or tenor of these debates are reflected in the annual Director's IRP Report, the stakeholder and utility comments provided on the draft Director's report, and the stakeholder comments on each of the utility IRPs. These documents can be found at https://www.in.gov/iurc/2630.htm.

C. State Utility Forecasting Group

The SUFG's projection for Indiana's resource requirements provides a useful perspective as a snapshot in time based on information from Indiana's utilities and using current models. However, the SUFG's analysis is not intended to suggest that it is an *optimal* long-term resource plan, as changing circumstances warrant continued review. Retirements of existing resources and other factors may accelerate or decelerate resource decisions. The SUFG is resource agnostic. Moreover, the SUFG does not assign the capacity requirement to specific utilities; rather, it is a statewide perspective.

1. SUFG History

The SUFG was created in 1985 when the Indiana legislature mandated, as a part of the CPCN statute, that a group be formed to develop and keep current a methodology for forecasting the probable future growth of electricity usage within Indiana. The Commission works with Purdue and Indiana Universities to accomplish this goal. The SUFG, currently housed on Purdue University's West Lafayette campus, produced its first projection in 1987 and has updated these projections periodically, usually biennially. The SUFG released its most recent forecast in December 2017.

2. SUFG Modeling Update

Under Ind. Code § 8-1-8.5-3.5(b), the SUFG must keep its modeling system current. In the 2015-2017 contract with the Commission, the SUFG acquired a new production costing and resource expansion program (AURORAxmp) and integrated the program in the modeling system. This was a major undertaking that resulted in increased efficiency in producing future forecasts and analyses. AURORAxmp has been populated with data specific to the Indiana utilities and the validation process is ongoing. New programs and modeling updates were part of the SUFG's December 2017 report.

In addition, updates to different components of the modeling system are done regularly on an as-needed basis. Expected areas of focus in 2017-2019 include a re-estimation of the industrial sector models for the investor-owned utilities by supplementing information from the utilities with updated information about various Indiana industries (steel, manufacturing, foundries, etc.).

Cause No. 45564

This includes production output, and local, state, and national economic information that can provide additional insights into the energy usage patterns of industrial customers, and a conversion of historical data from the Standard Industrial Classification system to the North American Industry Classification System.

III. Statutorily Required Information

A. Probable Future Growth of the Use of Electricity

Since the 1980s, forecasts for electricity demand by Indiana utilities and utilities across the nation have shown reductions in projected growth rates. More recently, growth rates of around one percent (or even negative for some utilities) have been common. While much of the low-growth rates and projected growth are attributed to increasing efficiency of electrical appliances (including LED lighting and improved appliance technologies) and industrial and commercial efficiencies for larger electricity users, low growth is also affected by economic swings and demographic changes. While recent history is instructive, it is not necessarily indicative of the future sales of electricity. Because of the significant costs and risks associated with either over- or under-forecasting electricity requirements, increasingly sophisticated mathematical models and databases are employed to improve the accuracy and credibility of load forecasting. Regardless of the analytical rigor, long-term forecasts of future electric needs cannot always predict unanticipated events (e.g., recessions, inflation, and technological change). As a result, the goal is to have a credible forecast with plausible explanations for the factors that determine electric use, and provide decision makers with a reasonable understanding of factors (e.g., scenarios or sensitivities) that, if changed, would alter the forecast and resource decisions.

Because uncertainties in load forecasting are a significant driving force for the long-term resource planning decisions of utilities, it is imperative that utilities continue to improve the rigor of their analyses, utilize state-of-the-art planning tools, and develop enhanced databases that include more information on their customers' current and future usage characteristics. The relatively rapid evolution of televisions, especially from cathode ray tubes to LEDs, provides an imperfect but reasonable corollary. Unexpected demographic trends, new industries (or closures of existing industries), technological changes, and recessions or more rapid economic growth are all factors that could significantly change the load forecast trajectories of Indiana utilities. It is for this reason that load forecasts and the entire IRP need to be redone on a three-year basis to incorporate new information and developments.

This section of the report shows projections of load growth developed by the SUFG, Indiana electric utilities, MISO, and the EIA. Each organization's load forecast was completed at different points in time and is based on different methodologies, data, and assumptions.

Cause No. 45564

1. Indiana Utilities' Forecasts

Indiana utilities project relatively low load growth and adequate resources to satisfy reliability requirements.

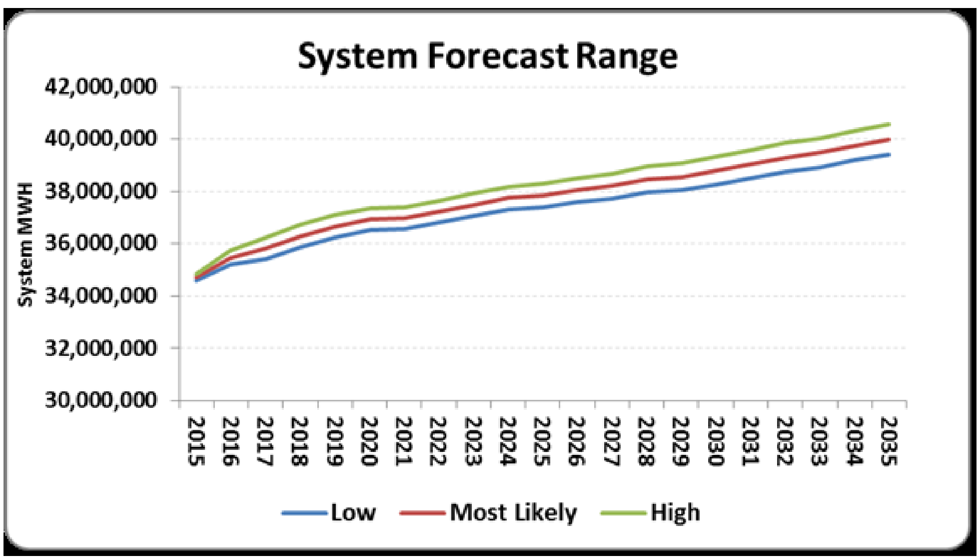
Projected Growth Rate of Energy and Peak Demand over the Planning Period*

Utility	Annual Energy	Peak Demand
Duke Energy (2016-2035)	0.7%	0.8%
Hoosier Energy (2018-2037)	0.7%	0.7%
Indiana Michigan Power Co. (2016-2035)	0.1%	0.2%
IMPA (2018-2037)	0.5%	0.5%
IPL (2016-2037)	0.5%	0.4%
NIPSCO (2017-2037)	0.3%	0.4%
SIGECO South (2016-2036)	0.5%	0.5%
Wabash Valley (2018-2036)	0.8%	0.8%

*The percentages are compound annual growth rates over the company-specific planning period.

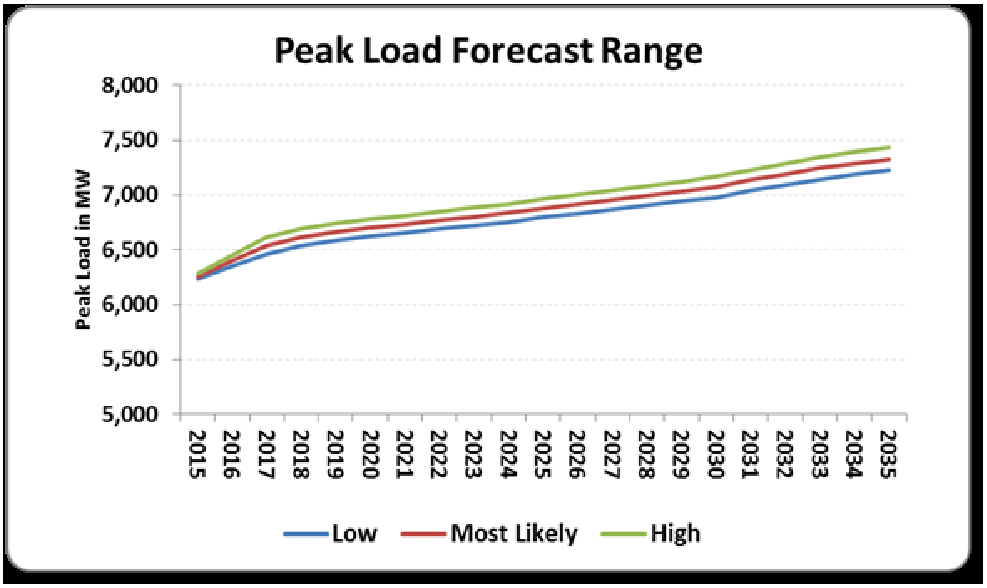
a) Duke Energy Indiana – 2015 IRP

Duke Energy notes that 2015 energy usage has not returned to pre-2007 (pre-recession) levels. Summer peak demand is forecast to grow at just under one percent per year, which is a little faster than energy use.



Source: Duke Energy Indiana 2015 IRP. Pg. 44

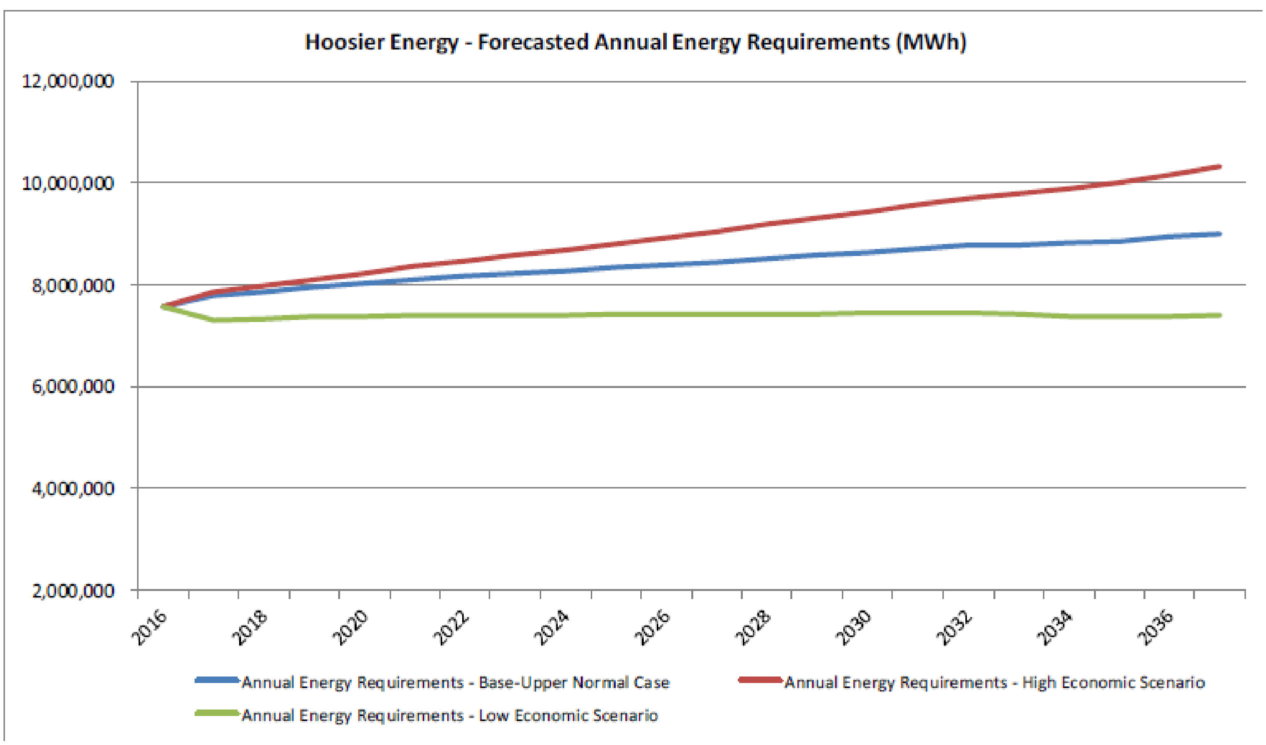
Cause No. 45564



Source: Duke Energy Indiana 2015 IRP. Pg. 44

b) Hoosier Energy – 2017 IRP

Hoosier Energy's 20-year projection shows both energy and annual peak growing at an annual average of 0.7 percent. Hoosier Energy noted that load growth has slowed due to a combination of energy efficiency gains, economic slowdown, and a decline in the energy intensity of gross domestic product.



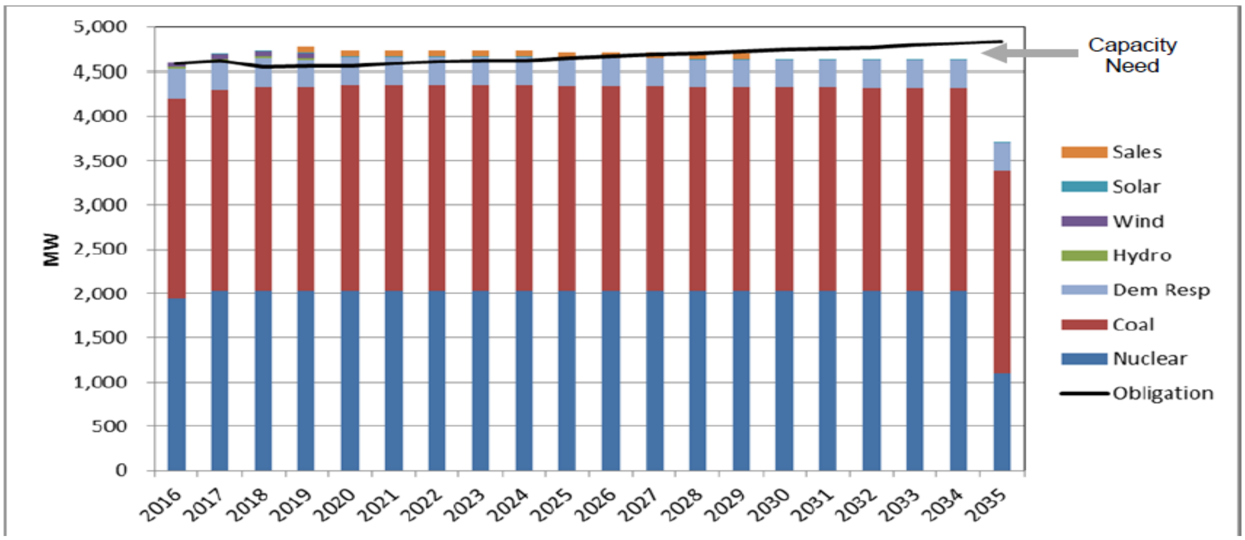
Source: Hoosier Energy 2017 IRP. Pg. 35

Cause No. 45564

c) Indiana Michigan Power – 2015 IRP

According to its 2015 IRP, I&M is forecasting energy and peak demand requirements to increase at a compound average growth rate of 0.2 percent through 2035. In 2015, I&M did not anticipate the need for additional capacity until 2035. I&M is reevaluating this assumption as it prepares its 2018 IRP. Energy efficiency and demand response were projected to reduce I&M's retail load by eight percent over the 2016-2035 planning horizon.

Indiana Michigan Power - Forecasting Energy and Peak Demand Requirements

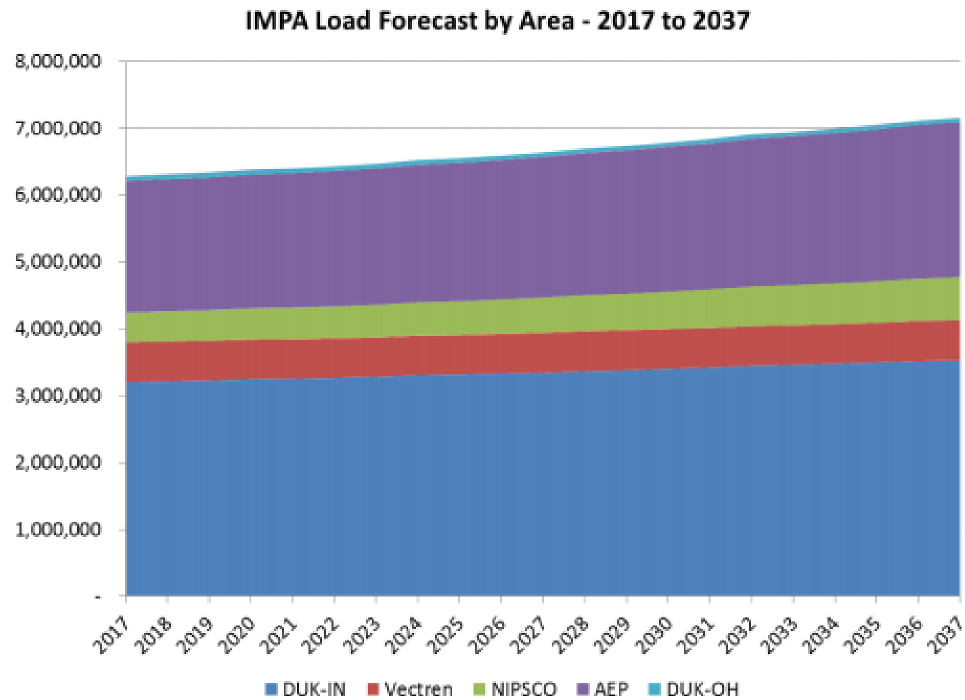


Source: Indiana Michigan Power 2015 IRP. Pg. ES-5

d) Indiana Municipal Power Agency – 2017 IRP

In 2017, IMPA's coincident peak demand for its 61 communities was 1,128 MW, and the annual member energy requirements during 2017 were 6,098,477 Megawatt hours (MWh). IMPA projects that its peak and energy demand will grow at approximately 0.6 percent per year. These projections do not include the addition of any new members or customers beyond those currently under contract. Since the last IRP was filed, IMPA has added one new member, the Town of Troy, Indiana. Additionally, in August of 2017, the Village of Blanchester, Ohio, which had been an IMPA customer since 2007, became an IMPA member. Members in the Duke, NIPSCO, and I&M areas are expected to experience growth, while those in the SIGECO and Duke Ohio region are expected to contract somewhat.

Cause No. 45564



Source: Indiana Municipal Power Agency 2017 IRP. Pg. 5-40

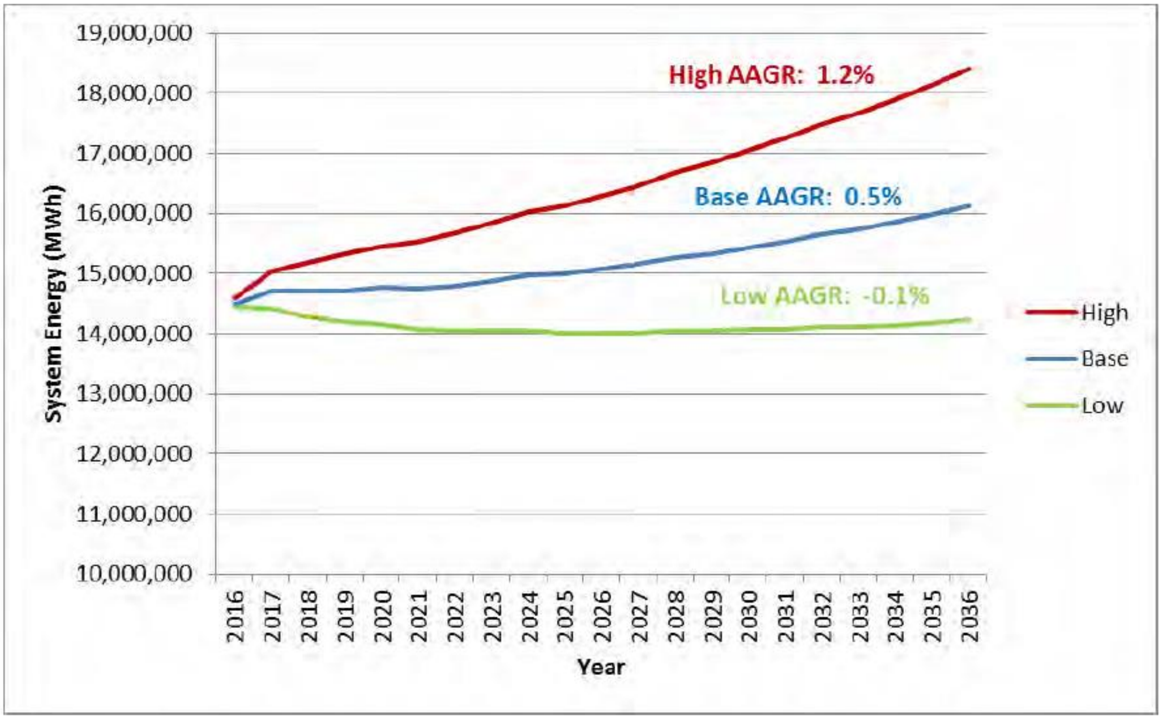
e) Indianapolis Power & Light Company – 2016 IRP

Since 2005, IPL's system energy requirements have been trending down. System energy requirements in 2015 were 14,471 GWh compared with 16,006 GWh in 2005. Energy use, on average, declined one percent annually over this period. IPL attributes the decline in customer usage to significant energy efficiency improvements in lighting, appliances, and end-use efficiency. In its IRP, IPL notes:

> [P]art of the decline can be [attributed] to the 2008 recession and the slow economic recovery. Between 2007 and 2011 customer growth actually declined 0.1% per year. Since 2011, customer growth bounced back with residential customer growth averaging 0.8% per year and non-residential customer growth averaging 0.4% per year. But despite increase in customer growth and business activity, sales have still been falling 1.0% per year. *Over the next twenty years, energy requirements are expected to increase 0.5% annually and system peak demand 0.4% annually, before adjusting for future DSM program savings* (emphasis added) (pg. 40).

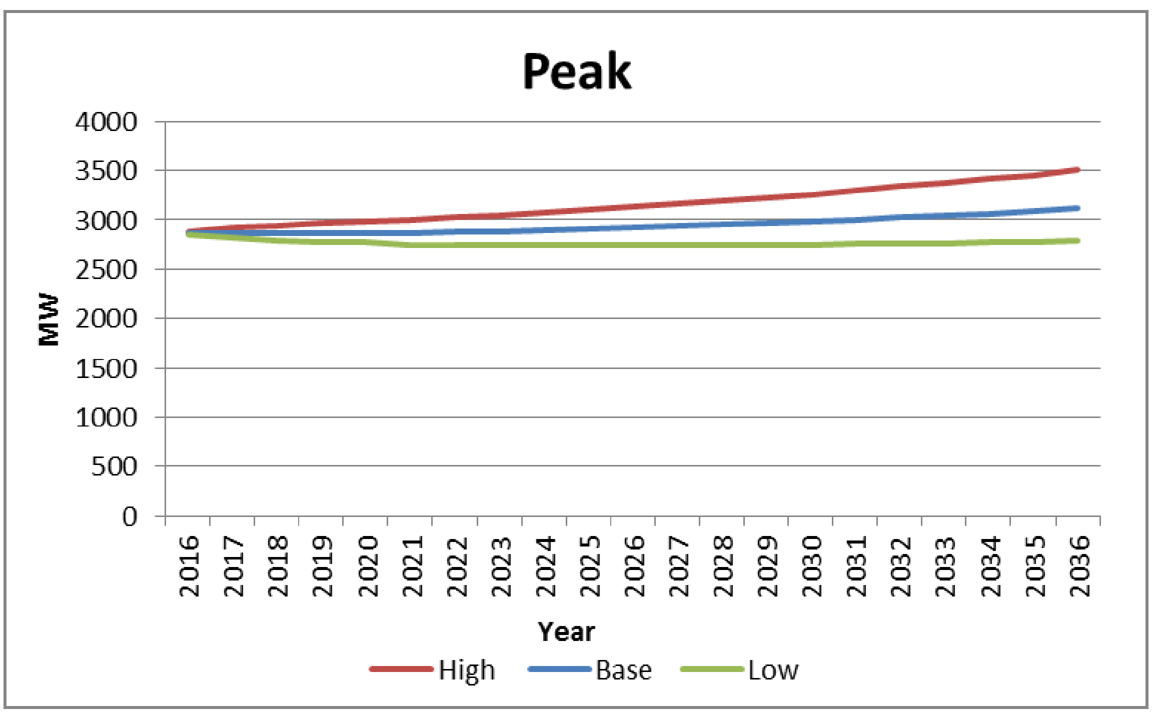
Cause No. 45564

IPL Forecasted Energy Requirements



** "AAGR" means "average annual growth rate."*
Source: Indianapolis Power & Light 2016 IRP. Pg. 141

IPL Forecasted Peak Demand



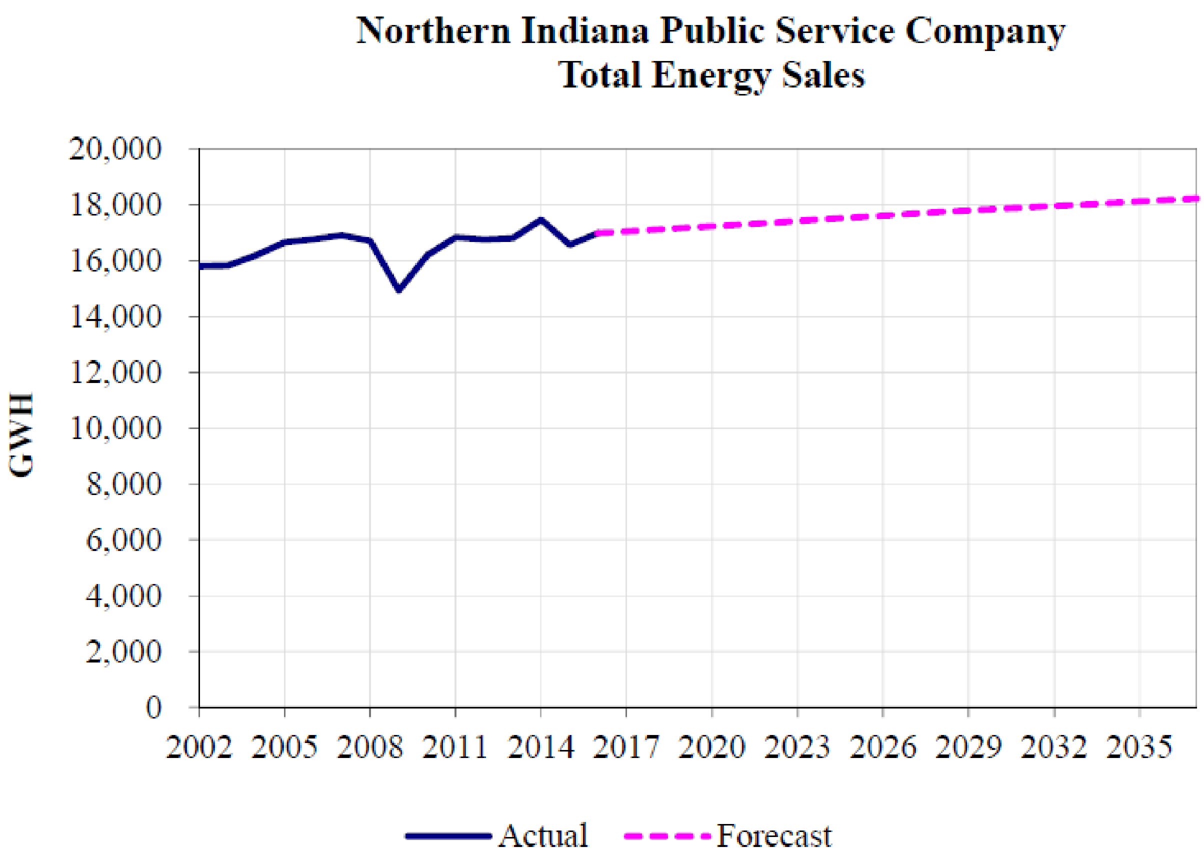
Source: Indianapolis Power & Light 2016 IRP. Pg. 142

Cause No. 45564

f) Northern Indiana Public Service Company – 2016 IRP

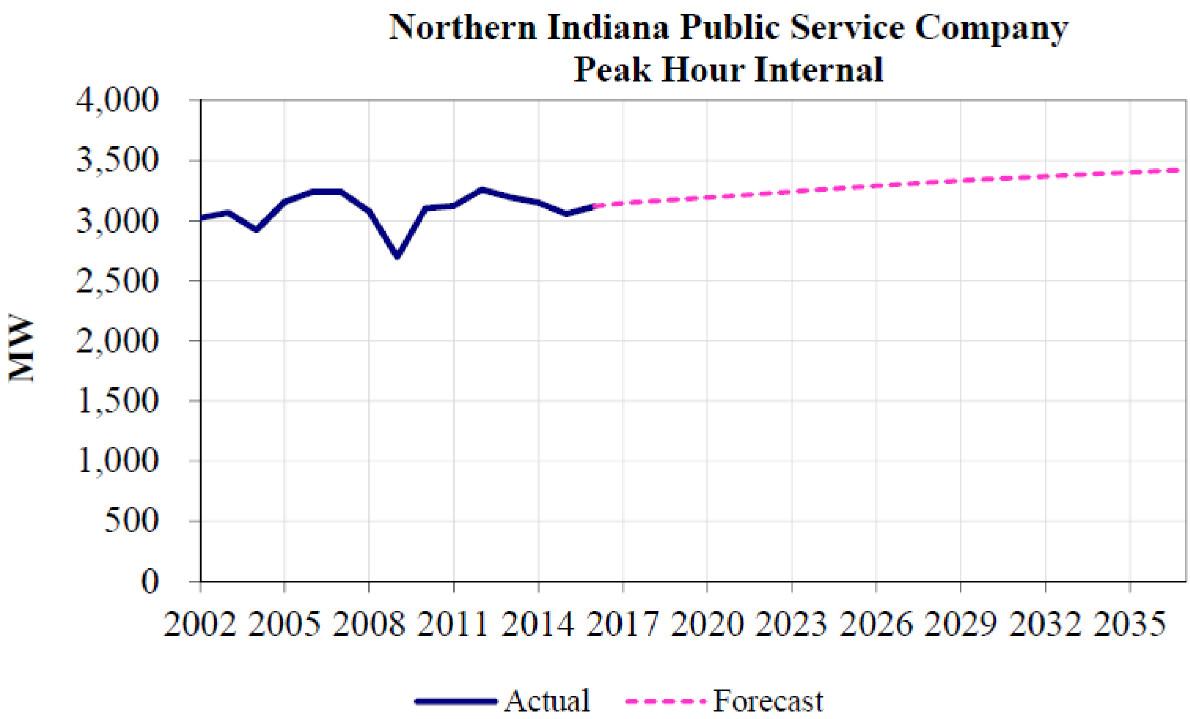
NIPSCO's forecast of its customers' electric requirements "project an increase in overall customer energy usage of 0.33% compound annual growth rate (CAGR) for the period of the IRP (2017 to 2037), while the peak demand for the base case is 0.45%. The total number of NIPSCO electric customers is projected to increase from approximately 464,000 today to about 511,000 by 2037".

Industrial load is particularly significant for NIPSCO. NIPSCO is projecting no growth for industrial load over the planning period. The potential addition or loss of a major customer and the ripple effects, or significant reductions in use due to technological change, could pose significant risks. Some of those risks could be beneficial, but others would not be. The following two graphs depict the low growth in energy sales and demand:



Source: Northern Indiana Public Service Company 2016 IRP. Pg. 28

Cause No. 45564

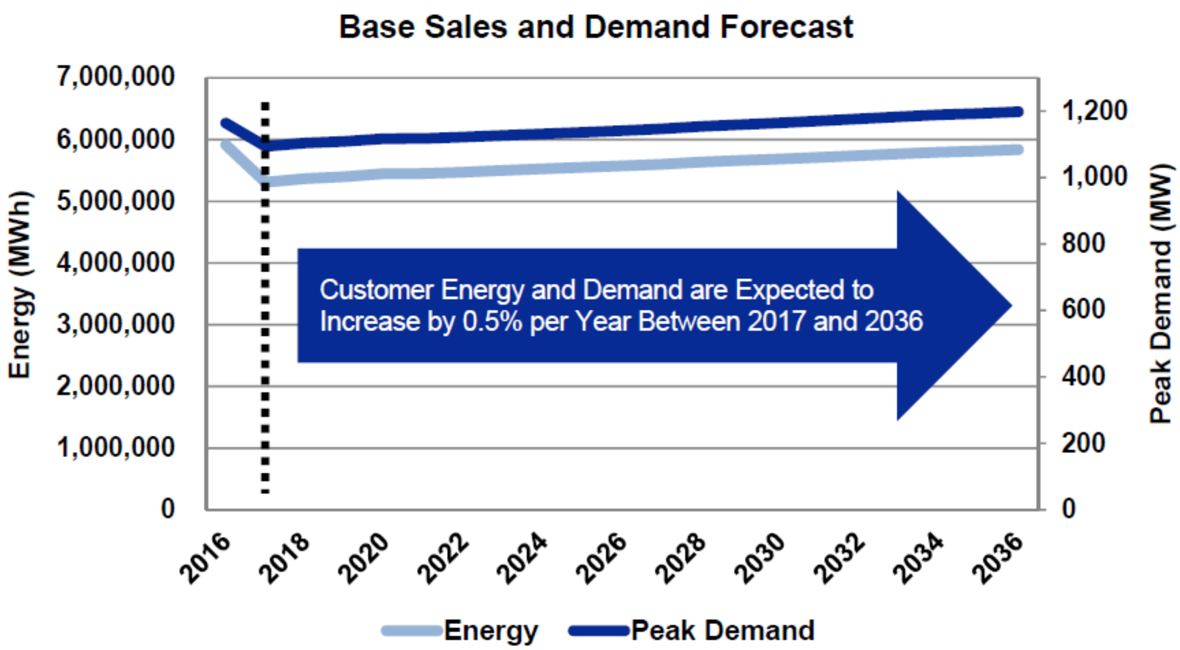


Source: Northern Indiana Public Service Company 2016 IRP. Pg. 30

g) Southern Indiana Gas & Electric Company – 2016 IRP

SIGECO has experienced very little load growth, and projections are showing this trend to continue through the planning horizon of 2036. Moreover, SIGECO has experienced significant loss of industrial load when a customer decided to meet much of its electricity needs by installing a customer-owned, large combined heat and power facility.

Cause No. 45564



Source: Southern Indiana Gas & Electric Company 2016 IRP. Pg. 36

h) Wabash Valley Power Association – 2017 IRP

Wabash Valley is forecasting 0.9 percent growth in energy sales demand for the 2018-2036 planning horizon. Each Wabash Valley Member serves a variety of residential, commercial and industrial loads. The majority of the load is residential in nature. The Company's winter peak usually occurs at 8:00 p.m. and the summer peak generally occurs in the evening around 7:00 p.m. These peak times reflect the highly residential nature of Wabash Valley's load. Wabash Valley has two large customers whose demand may be interrupted.

Cause No. 45564

Base Case Load Forecast Energy Sales and Summer Coincident Peak Forecast (Net of Pass-Through Loads)

Year	Energy Sales (GWh)	% Change	Summer Coincident Peak (MW)	% Change
2017	7,401		1,475	
2018	7,277	-1.7%	1,472	-0.2%
2019	7,347	1.0%	1,476	0.3%
2020	7,382	0.5%	1,482	0.4%
2021	7,391	0.1%	1,489	0.5%
2022	7,435	0.6%	1,499	0.7%
2023	7,500	0.9%	1,512	0.9%
2024	7,590	1.2%	1,525	0.9%
2025	7,628	0.5%	1,537	0.8%
2026	7,696	0.9%	1,551	0.9%
2027	7,782	1.1%	1,568	1.1%
2028	7,895	1.5%	1,586	1.1%
2029	7,964	0.9%	1,605	1.2%
2030	8,034	0.9%	1,620	0.9%
2031	8,105	0.9%	1,635	0.9%
2032	8,205	1.2%	1,652	1.0%
2033	8,260	0.7%	1,668	1.0%
2034	8,336	0.9%	1,684	1.0%
2035	8,422	1.0%	1,702	1.1%
2036	8,531	1.3%	1,719	1.0%
18-36		0.9%		0.9%

Source: Wabash Valley Power Association 2017 IRP. Pg. 39

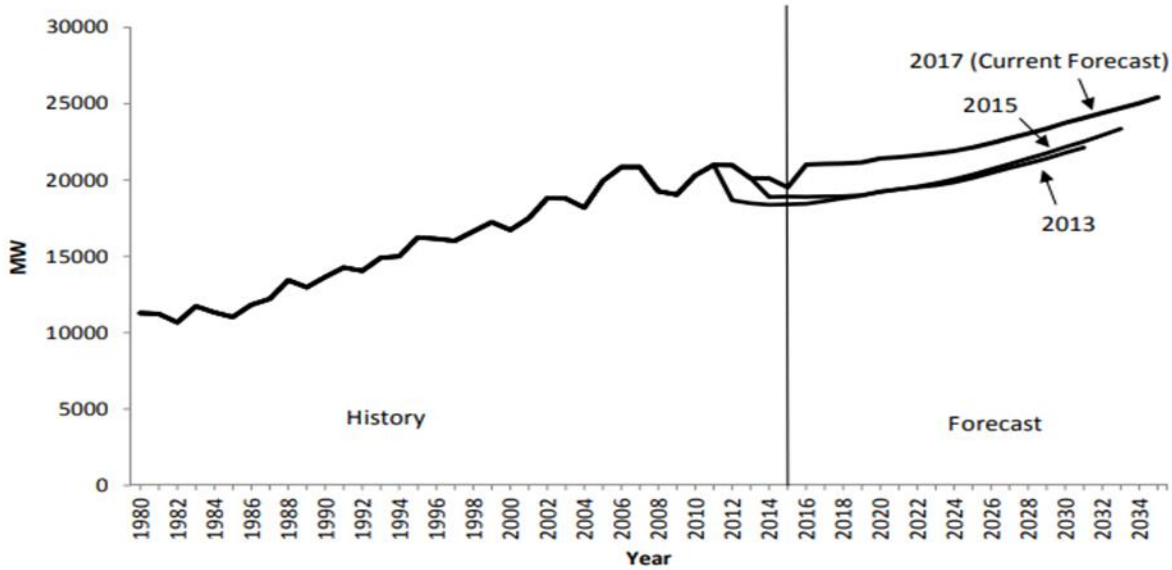
2. State Utility Forecasting Group Forecast

The SUFG summarized its forecast of projected customer electric power needs in its *Indiana Electricity Projections: The 2017 Forecast* as follows:

> The projections in this forecast are lower than those in the 2015 forecast, primarily due to increases in energy efficiency and less optimistic economic projections, compared to the earlier projections. This forecast projects electricity usage to grow at a rate of 1.12 percent per year over the 20 years of the forecast. Peak electricity demand is projected to grow at an average rate of 1.01 percent annually. This corresponds to about 230 megawatts (MW) of increased peak demand per year. The growth in the second half of the forecast period (2026-2035) is stronger than the growth in the first ten years (pg. 1-1).

The 2017 forecast predicts Indiana electricity prices to continue to rise in real (inflation adjusted) terms through 2023 and then slowly decrease afterwards. A number of factors determine the price projections. These include costs associated with future resources required to meet future load, costs associated with continued operation of existing infrastructure, and fuel costs. Costs are included for the transmission and distribution of electricity, in addition to production.

Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



Source: State Utility Forecasting Group's 2017 Electricity Projections. Pg. 1-4

Indiana Peak Demand Requirements Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2017	1.01	2016-2035
2015	1.13	2014-2033
2013	0.90	2012-2031

Source: State Utility Forecasting Group's 2017 Electricity Projections. Pg. 3-1

Annual Electricity Sales Growth (Percent) by Sector (Current Forecast vs. 2015 Projections)

Sector	Current (2016-2035)	2015 (2014-2033)
Residential	0.48	0.64
Commercial	0.36	0.59
Industrial	2.04	1.90
Total	1.12	1.17

Source: State Utility Forecasting Group's 2017 Electricity Projections. Pg. 3-3

Cause No. 45564

3. Regional Forecast

The SUFG also conducts a load forecast for MISO. Like the SUFG's load forecast for Indiana, the MISO region is projecting very low growth rates in energy usage and demand. PJM and other regions are also expecting low load growth.

SUFG State Retail Sales (without EE Adjustments) for the MISO Region Compound Annual Growth Rates (2018-2037)

State	CAGR
Arkansas	1.06
Illinois	0.51
Indiana	1.28
Iowa	1.55
Kentucky	0.87
Louisiana	0.80
Michigan	0.88
Minnesota	1.52
Mississippi	1.46
Missouri	0.97
Montana	1.14
North Dakota	0.99
South Dakota	1.65
Texas	1.86
Wisconsin	1.36

LRZ Metered Load Annual Growth Rates (2018-2037)

LRZ	CAGR (without EE Adjustments)	CAGR (with EE Adjustments)
1	1.45	1.34
2	1.32	1.32
3	1.51	1.18
4	0.51	0.31
5	0.81	0.64
6	1.12	1.03
7	0.88	0.76
8	1.06	1.05
9	1.05	0.99
10	1.46	1.46

Source: State Utility Forecasting Group's MISO Independent Load Forecast Update. Pg. ES-2

The maximum peak demand experienced by MISO and PJM is more relevant to resource planning than the maximum demand incurred by their member systems. Specifically, MISO and PJM *coincident peak demand* [2]become the primary basis for determining the operating and planning reserve requirements (Resource Adequacy) for their regions. The MISO and PJM system wide reliability requirements are, in turn, allocated to their member utilities (in Load Resource Zones) based on their contributions to the MISO and PJM systems' coincident peak demand (*coincidence factor*).

[2] **Coincident Peak Demand (CP):** For example, in regions served by RTOs / ISOs, the relevant peak is the RTOs / ISOs peak demand rather than the peak demand of any utility or other entity. In regions not served by RTOs / ISOs, the relevant peak is the contribution of each customer to their utility's peak demand. For retail ratemaking CP typically refers to the utility's peak demand since the timing of the RTO / ISO peak is difficult to predict, most Indiana utilities experience a peak that is close to the MISO's and PJM's peak. Therefore, Indiana utilities have a high coincidence factor with MISO and PJM.

Cause No. 45564

LRZ Non-Coincident Summer and Winter Peak Demand (with EE Adjustments) Compound Annual Growth Rates for MISO (2018-2037)

LRZ	CAGR (with EE Adjustments on Non-Coincident Peak)	
	Summer	Winter
1	1.34	1.32
2	1.32	1.32
3	1.19	1.12
4	0.33	0.29
5	0.67	0.64
6	1.03	1.02
7	0.78	0.74
8	1.05	1.05
9	0.99	0.98
10	1.46	1.46

Source: State Utility Forecasting Group's MISO Independent Load Forecast Update. Pg. ES-2

4. National Forecast

According to the EIA and consistent with the experience of Indiana utilities and the region, electricity demand is largely driven by economic growth and increasing efficiency of the production and usage of electricity. Nationally, electricity demand growth was negative in 2017 but is projected to rise slowly through 2050. From 2017–2050, the average annual growth in electricity demand reaches about 0.9 percent in the Annual Energy Outlook 2018 Reference case. Through the projection period, the average electricity growth rates in the High and Low Economic Growth cases deviate from the Reference case the most—where the High Economic Growth case is about 0.3 percentage points higher than in the Reference case, and electricity growth in the Low Economic Growth case is about 0.3 percentage points lower than in the Reference case.

Cause No. 45564

B. Future Resource Needs

With all the utilities, the predicted need for additional resources begins with the predicted annual energy and peak demand requirements. Future resource needs will therefore vary with the predicted energy and peak demand requirements. IRPs typically will analyze multiple scenarios, or possible states of the world, to bracket differences between forecasts. The utilities may, for example, include low-growth, base-growth, and high economic-growth scenarios. Energy use changes with the economy, and so too will the need for additional resources. As was noted earlier, each assessment or forecast was prepared at different times with different methodologies, models, data, and assumptions regarding key inputs such as natural gas prices and the impact of technological change on renewables, DERs, and storage. Any analysis is a snapshot in time. The following summaries of the needs for future resources are therefore only applicable under the specific scenario to which it applies.

Cause No. 45564

1. State Utility Forecasting Group Projections

In its *Indiana Electricity Projections: The 2017 Forecast*, the SUFG summarized its 2017 forecast regarding future resource needs as follows:

> For this forecast, SUFG has incorporated significant revisions to its modeling system. As a result, unlike in previous forecasts, future resource needs are identified by a specific technology rather than by generic baseload, cycling and peaking types. The new utility simulation model can select the lowest cost mix of a number of different supply and demand options. Due to time and data limitations, demand-side resources were modeled as fixed quantities based on utility-provided information rather than allowing the model to select the amounts.
>
> This forecast indicates that additional resources are not needed until 2021. This forecast identifies a need for about 3,600 MW of additional resources by 2025, 6,300 MW by 2030 and 9,300 MW at the end of the forecast period in 2035. In the long term, the projected additional resource requirements are higher than in previous forecasts. This is due to the retirements of additional existing generators that have been announced by Indiana utilities since the previous forecast report (pg. 1-1).

2. Indiana Utilities' Projections of Resource Needs

a) Duke Energy Indiana – 2015 IRP

Duke's IRP for the 2015-2035 planning horizon is shown in the following table. The IRP includes the addition of two combined cycle facilities of 448 MW each – one in 2020 and the other in 2031. The IRP also determined a number of regular additions of wind and solar in relatively small increments, approximately 50 MW a year and 30 MW a year, respectively, from about 2020 through 2030. These additions come mostly after a number of anticipated retirements: five units at Wabash River (668 MW) in 2016; Connersville 1&2 combustion turbines (86 MW) in 2018, Gallagher units 2 & 4 (280 MW) in 2019, and Gibson 5 (310 MW) in 2031.

Cause No. 45564

Duke Energy Indiana Integrated Resource Plan
Portfolio and Recommended Plan (2015-2035)

Year	Retirements	Additions	Renewables (Nameplate MW) [1]			Notable, Near-term Environmental Control Upgrades [2]
			Wind	Solar	Biomass	
2015						
2016	Wabash River 2-6 (668 MW)			20		
2017				20		Ash handling/Landfill upgrades: Cayuga 1-2 & Gibson 1-5
2018	Connersville 1&2 CT (86 MW) Mi-Wabash 1-3,5-6 CT (80 MW)					
2019	Gallagher 2 & 4 (280 MW)					
2020		CC 448 MW Cogen 15MW		10	2	
2021				10	2	
2022			50	20		
2023			50	30	2	
2024			50	30	2	
2025				30		
2026			50	20	2	
2027			50	30		
2028			100	30	2	
2029			50	30	2	
2030				10		
2031	Gibson 5 (310 MW)	CC 448 MW				
2032						
2033		CT 208 MW				
2034						
2035			50			
Total MW	1424	1119	450	290	14	

1: Wind and solar MW represent nameplate capacity.
2: Additional likely or potential control requirements include additives for mercury control, water treatment and intake structure modifications in the 2016 -2023 time frame.

Source: Duke Energy Indiana 2015 IRP. Pg. 158

b) Hoosier Energy – 2017 IRP

Hoosier Energy's IRP does not show a resource deficit until 2024. The Capacity Expansion Plan below shows Hoosier Energy's intention of adding a significant amount of renewable resources beginning in 2020.

Cause No. 45564

Capacity Expansion Plan - Summer Peak

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Peak Demand										
Demand Forecast (1)	1,524	1,544	1,562	1,578	1,599	1,628	1,642	1,656	1,670	1,682
Demand Response/Energy Efficiency	(46)	(47)	(46)	(45)	(46)	(47)	(49)	(50)	(50)	(50)
Reserve Requirement (2)	124	126	127	129	130	133	134	135	136	137
Peak Requirement	1,602	1,623	1,643	1,662	1,683	1,714	1,727	1,741	1,756	1,769
Resources (MW)										
Merom	983	983	983	983	983	983	983	983	983	983
Power Purchase	150	150	150	150	150	150	50	50	0	0
Holland	307	307	307	307	307	307	307	307	307	307
Worthington	169	169	169	169	169	169	169	169	169	169
Lawrence	175	175	175	175	175	175	175	175	175	175
Renewables (3)	122	97	247	347	347	347	347	347	347	347
Adj. per MISO RAR (4)	(196)	(171)	(294)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
Total Resources Adjusted	1,709	1,709	1,736	1,755	1,755	1,755	1,655	1,655	1,605	1,605
Total Resources minus Peak Req.										
Excess / (Deficit)	107	87	93	94	72	42	(71)	(86)	(151)	(164)

Source: Hoosier Energy 2017 IRP. Pg. 57

c) Indiana Michigan Power – 2015 IRP

I&M is a case study in how quick and significant market dynamics, combined with legal and regulatory circumstances, can change a utility's resource decisions. Based on I&M's 2018 IRP that is under development, I&M is assessing potentially significant changes beyond those contemplated in its 2015 IRP. According to the 2015 IRP, I&M did not anticipate the need for large scale additional capacity until 2035, when it forecast the need for 1,253 MW of natural gas combined cycle generation coupled with a reduction in energy needs based on its energy efficiency programs. It also anticipated the addition of 600 MW of new solar generation throughout the 20 year period.

I&M's 2018 IRP is being developed with a target completion date of February 1, 2019. I&M is planning to thoroughly review the potential for terminating the Rockport Unit 2 contract as early as 2023 and the closing of Rockport 1 by 2028. Economic, legal, and regulatory considerations are driving exploration of these options, among other considerations. It is important to keep in mind that the analysis is not complete and many factors will be considered prior to any decisions being made.

d) Indiana Municipal Power Agency – 2017 IRP

IMPA anticipates a need for market purchases through 2025 to provide a small amount of capacity and energy needed due to the expiration of a 100 MW power purchase agreement in 2021. From 2018 through 2027, IMPA anticipates much of its new resources will be solar and wind. After 2026, IMPA expects to have adequate resources with the addition of one or more combined cycle units.

Cause No. 45564

Year	Capacity Losses MW Lost	Resource	Capacity Additions MW Added	Resource	Net MW
2018	(50)	PPA Expires	12 100	Solar Bilateral Capacity (18-20)	62
2019	(50)	Wind PPA Expires	12 50	Solar Wind PPA	12
2020			12	Solar	12
2021	(100) (100)	PPA Expires Bilateral Capacity Expires	12 200	Solar Bilateral Capacity (21-25)	12
2022			12	Solar	12
2023			12	Solar	12
2024			12	Solar	12
2025			12	Solar	12
2026	(90) (200)	WWVS Retires Bilateral Capacity Expires	12 200 50	Solar Advanced CC Wind PPA	(28)
2027			12	Solar	12
2028			12	Solar	12
2029					
2030					
2031					
2032					
2033					
2034	(190)	PPA Expires	260	Advanced CC	70
2035					
2036					
2037					
Total	(780)		992		212

Source: Indiana Municipal Power Agency 2017 IRP. Pg. 1-13

e) Indianapolis Power & Light Company – 2016 IRP

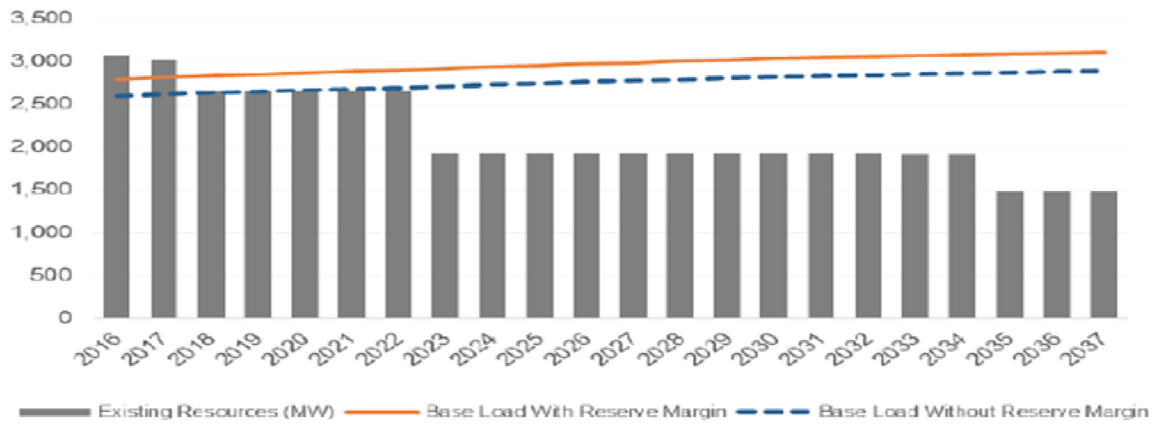
IPL's IRP includes a table showing all generation retirements and reductions under its six different scenarios.

Cause No. 45564

Annual Supply-Side Capacity Additions and Retirements

YEAR	Base Case	Robust Economy	Recession Economy	Strengthened Environmental Rules	High Customer Adoption of Distributed Generation	Quick Transition
2017						
2018	**Upgrade Pete 1-4**	**Upgrade Pete 1-4**	**Refuel Pete 1 - 4**	**Retire Pete 1 (-234 MW) Coal, Refuel Pete 2-3&4 (1495 MW) to NG**	**Upgrade Pete 1-4**	**Upgrade Pete 1-4**
2019						
2020				Wind 500 MW PV 280 MW		
2021						
2022				Wind 100 MW PV 50 MW	PV 65 MW Wind 10 MW CHP 75 MW	**Retire Pete 1 (-234 MW) Coal, Refuel Pete 2-3&4 (1495 MW) to NG**
2023	**Retire HS GT 1&2 (-32 MW) Oil**	**Retire HS GT 1&2 (-32 MW) Oil**	**Retire HS GT 1&2 (-32 MW) Oil**	**Retire HS GT 1&2 (-32 MW) Oil** PV 10 MW	**Retire HS GT 1&2 (-32 MW) Oil**	**Retire HS GT 1&2 (-32 MW) Oil**
2024				PV 10 MW		
2025					PV 65 MW Wind 10 MW CHP 75 MW	
2026				PV 10 MW		
2027				PV 10 MW		
2028				PV 10 MW Comm Solar 1 MW		
2029				PV 10 MW Comm Solar 5 MW		
2030	**Retire HS 5&6 (-200MW) NG**	**Retire HS 5&6 (-200MW) NG** Wind 500 MW	**Retire HS 5&6 (-200MW) NG**	**Retire HS 5&6 (-200MW) NG** Wind 500 MW	**Retire HS 5&6 (-200MW) NG**	**Retire Pete 2-4 (-1495 MW) NG, HS GT4-6 (294 MW) NG, HS 5&6 (-200 MW) NG, HS IC1 (3 MW) Oil, Pete IC1-3 (8 MW) Oil** Wind - 6000 MW Solar - 1146 MW Battery - 600 MW
2031		Wind 500 MW Market 200 MW		Wind 500 MW		
2032	**Retire Pete 1 (-234 MW) Coal**	**Retire Pete 1 (-234 MW) Coal** Wind 500 MW PV 370 MW	**Retire Pete 1 (-234 MW) Coal**	Wind 500 MW Comm Solar 3 MW	**Retire Pete 1 (-234 MW) Coal** PV 65 MW Wind 510 MW CHP 75 MW	
2033	**Retire HS7 (-428 MW) NG** Wind 250 MW Market 50 MW PV 90 MW Battery 100 MW	**Retire HS7 (-428 MW) NG** Wind 500 MW PV 440 MW	**Retire HS7 (-428 MW) NG**	**Retire HS7 (-428 MW) NG** Wind 500 MW Comm Solar 5	**Retire HS7 (-428 MW) NG** Wind 500 MW	**Retire HS7 (-428 MW) NG**
2034	**Retire Pete 2 (-417 MW) Coal** H-Class CC 450 MW Wind 250 MW	**Retire Pete 2 (-417 MW) Coal** H-Class CC 450 MW Wind 500 MW	**Retire Pete 2 (-417 MW) NG** H-Class CC 450 MW	**Retire Pete 2 (-417 MW) NG** H-Class CC 450 MW Wind 500 MW Comm Solar 5 MW	**Retire Pete 2 (-417 MW) Coal** H-Class CC 450 MW Wind 500 MW	H-Class CC 450 MW
2035	Wind 250 MW Battery 250 MW Market 150 MW	Wind 500 MW PV 190 MW Battery 250 MW Market 50 MW Comm Solar 1 MW	H Class CC 200 MW	Wind 500 MW PV 70 MW Market 50 MW Comm Solar 5 MW	Wind 500 MW Battery 50 MW Market 50 MW	
2036	Wind 250 MW Battery 150 MW PV 10 MW	Wind 500 MW Battery 50 MW Comm Solar 5 MW		Wind 500 MW PV 60 MW Comm Solar 5 MW	Wind 500 MW PV 60 MW Comm Solar 1 MW	
* Upgrades for Pete 1-4 for NAAQS SO2 and CCR						

Cause No. 45564



Source: Northern Indiana Public Service Company 2016 IRP. Pg. 55

In September 2018, NIPSCO's IRP update suggests that all four Schahfer units may be retired by year-end 2023 due to being uneconomic in the current wholesale power market. The IRP also indicates that Michigan City may also be retired in 2028 for economic reasons. The preliminary plan is for the retired capacity to be replaced by a combination of renewables based on a competitive bidding process.

g) Southern Indiana Gas & Electric Company – 2016 IRP

In IURC Cause No. 45052, SIGECO is proposing to diversify its generation fleet based on its 2016 IRP by investing in a new combined cycle gas turbine, sized to replace certain coal-fired units that will be retired at the end of 2023. SIGECO is seeking a CPCN to construct the combined cycle gas turbine, with the capacity of 800-900 MW, adjacent to SIGECO's Brown Generating Station.

Consistent with its 2016 IRP, SIGECO plans to retire Culley Unit 2 and the Brown Units 1 and 2 once the new plant is operational. According to SIGECO, Culley Unit 2's age and efficiency will not justify further capital investment to allow it to continue to operate in the future. Brown Units 1 and 2 would require significant capital investment, including construction of a new scrubber, to allow them to continue to operate in the future. Although SIGECO has agreed to continue its joint operation of Warrick Unit 4 through December 31, 2023, the continued operation of that unit is not economical and is further complicated because ALCOA, following its recent organizational and operational changes, is not able to unconditionally commit to use of the jointly-owned unit as part of its future operations.[3] Based on the 2016 IRP and updated IRP modeling completed in 2017, SIGECO plans to retire 73 percent of its current coal-fired generation fleet and diversify its generation portfolio by adding the combined cycle gas turbine at the end of 2023.

[3] ALCOA owns and operates four coal-fired generating units that provide electricity to its aluminum operations. SIGECO owns half of unit 4. The uncertainty of the continued operation of Warrick 4 depends on ALCOA's decision to continue its aluminum operations. No final determination has been made but is subject to on-going review.

Cause No. 45564

h) Wabash Valley Power Association – 2017 IRP

For the 2017-2036 IRP period, Wabash Valley's IRP indicates capacity needs starting in 2018, and Wabash Valley anticipates meeting these needs in a diversified manner. Wabash Valley, unlike most utilities in Indiana and the MISO region, has winter peak demands that sometimes exceed its summer peak demand.

From 2018 to 2020, Wabash Valley expects to meet its incremental capacity needs primarily by purchasing capacity through MISO's capacity auctions or bilateral transactions. Wabash Valley will purchase output from three wind projects from 2018 to 2020. After 2020, Wabash Valley's resource plan anticipates building 600 MW of baseload combined cycle resources and 350 MW of peaking combustion turbine resources along with 50 MW of energy efficiency. The expiration of existing power purchase agreements drives the need for these resources.

C. Resource Mix and Location

The location of new resources is dependent on the specific utility's transmission topology, fuel sources, type and size of generation, and other factors. The location of current generation resources will change over time as generating units are retired and new generating units are built. The location of new generating units may also be influenced by energy efficiency, demand response, distributed energy resources and future transmission, distribution, and generation technologies. A map of the current location of generation resources is found in Appendix 7.

1. Indiana Utilities' Projected Resource Mix

When analyzing the generation resource mix in Indiana, retirements of existing coal resources are of primary focus. Within the last 20 years, environmental regulations have imposed significant costs on coal-fired generation, in particular. The capital costs associated with environmental retrofits and equipment necessary to comply with U.S. EPA requirements, including fixed operations and maintenance expenses, were significant. Beginning around 2010, however, hydraulic fracturing (fracking) has resulted in a paradigm change in the natural gas markets that resulted in lower prices and reduced price volatility. Significant improvements also occurred in the engineering performance and economics of renewable energy resources, distributed energy resources, energy storage, and energy efficiency. As a result, the comparative economics of different energy resources requires closer examination before any resource commitments are made.

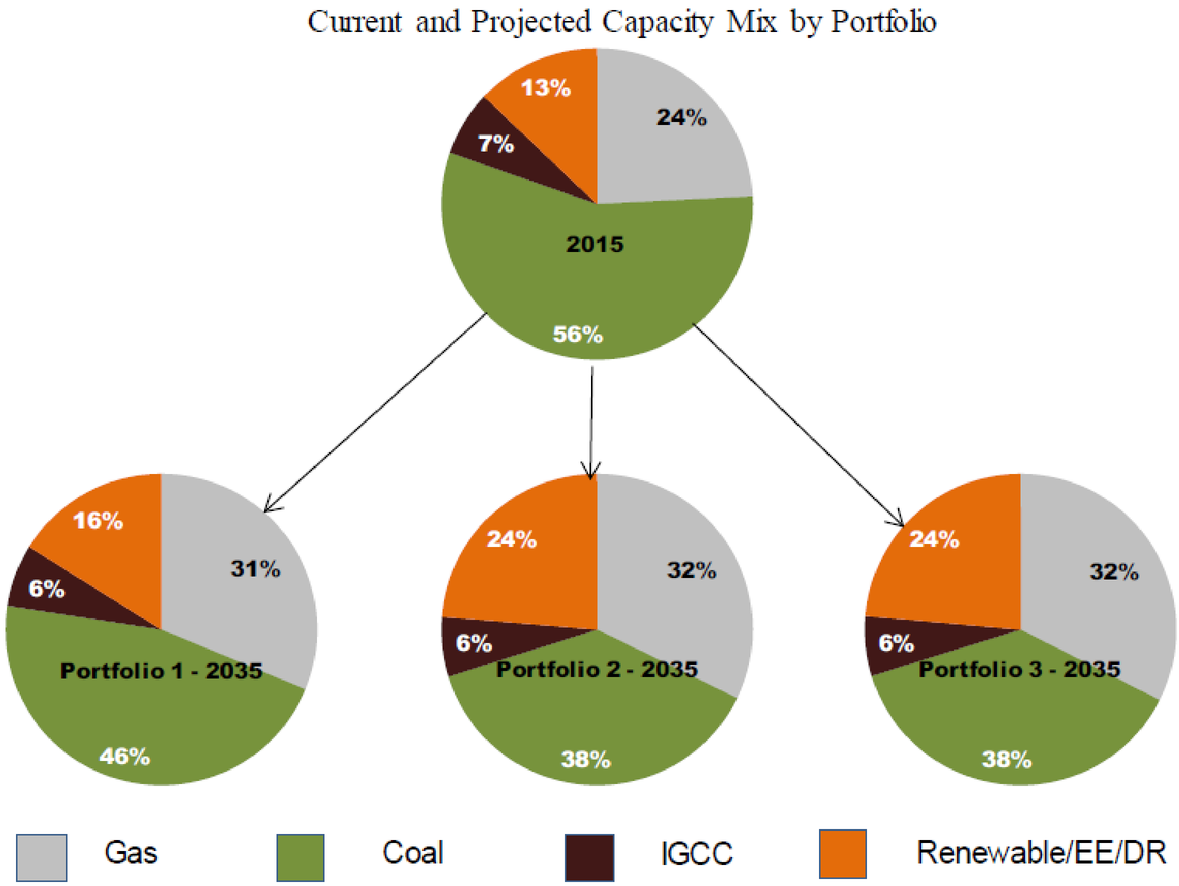
a) Duke Energy Indiana – 2015 IRP

Duke Energy's total installed net summer generation capability owned or purchased by Duke Energy is currently 7,507 MW. This capacity consists of 4,765 MW of coal-fired steam capacity, 595 MW of syngas/natural gas combined cycle capacity, 285 MW of natural gas-fired combined cycle capacity, 45 MW of hydroelectric capacity, and 1,804 MW of natural gas-fired or oil-fired peaking capacity. Also included is a power purchase agreement with Benton County Wind Farm (100 MW, with 13 MW contribution to peak modeled).

Cause No. 45564

Duke Energy's recommended plan for the 2015-2035 planning horizon is shown in the following table. The plan includes the retirement of five combustion turbines at Wabash River (668 MW) in 2016, Connersville 1&2 combustion turbines (86 MW) in 2018, Gallagher units 2 & 4 (280 MW) in 2019, and Gibson 5 (310 MW) in 2031. The plan also included the addition of two combined cycle facilities of 448 MW each – one in 2020 and the other in 2031. Resource additions also included regular additions of wind and solar in relatively small increments.

Duke Energy's Generation Mix 2015 and 2035



Source: Duke Energy Indiana 2015 IRP. Pg. 16

b) Hoosier Energy – 2017 IRP

Hoosier Energy does not show a resource deficit until 2024-25. Hoosier Energy's preferred capacity expansion plan suggests adding 891 MW of additional solar and wind over the planning period, as well as 205 MW of combustion turbines in 2024. The preferred plan also shows 208 MW of retirements of contracts through the 2018 – 2037 planning horizon.

Cause No. 45564

Hoosier Energy Projected Resource Requirements

Year	Retirements	Additions
2018		Meadow Lake Wind (25 MW); Orchard Hills LFG (16 MW)
2019	Story County PPA (25 MW)	
2020		Meadow Lake Wind (50 MW); Solar PPA (100 MW)
2021		Solar PPA (100 MW)
2022		
2023		
2024	Duke Energy PPA (100 MW)	Combustion Turbine (205 MW)
2025		
2026	Duke Energy PPA (50 MW)	
2027		
2028	Clark-Floyd LFG (4 MW)	
2029	Rail Splitter PPA (25 MW)	
2030		
2031		
2032	Dayton Hydro (4 MW)	
2033		
2034		
2035		Solar PPA (200 MW)
2036		Solar PPA (200 MW)
2037		Solar PPA (200 MW)
Total MW	**208**	**1,096**

Source: Hoosier Energy 2017 IRP. Pg. 92

c) Indiana Michigan Power – 2015 IRP

I&M's resource mix will be highly dependent on a decision regarding the Rockport generating units and its resource alternatives. I&M's 2015 IRP is being updated in 2018 and the future resource mix is likely to be different than predicted in 2015. The 2015 IRP, however, remains the most recently submitted information. It describes the change in its generation mix during its 20 year IRP period based on its preferred resource portfolio. It notes the energy output attributable to coal-based assets decreases from 40 percent to 33 percent, while nuclear generation shows a decrease from 53 percent to 38 percent over the period. Likewise, in addition to energy from a new natural gas combined cycle plant, which would comprise 15 percent of its resource portfolio, renewable energy would be anticipated to increase from 6 percent to 13 percent over the planning period.

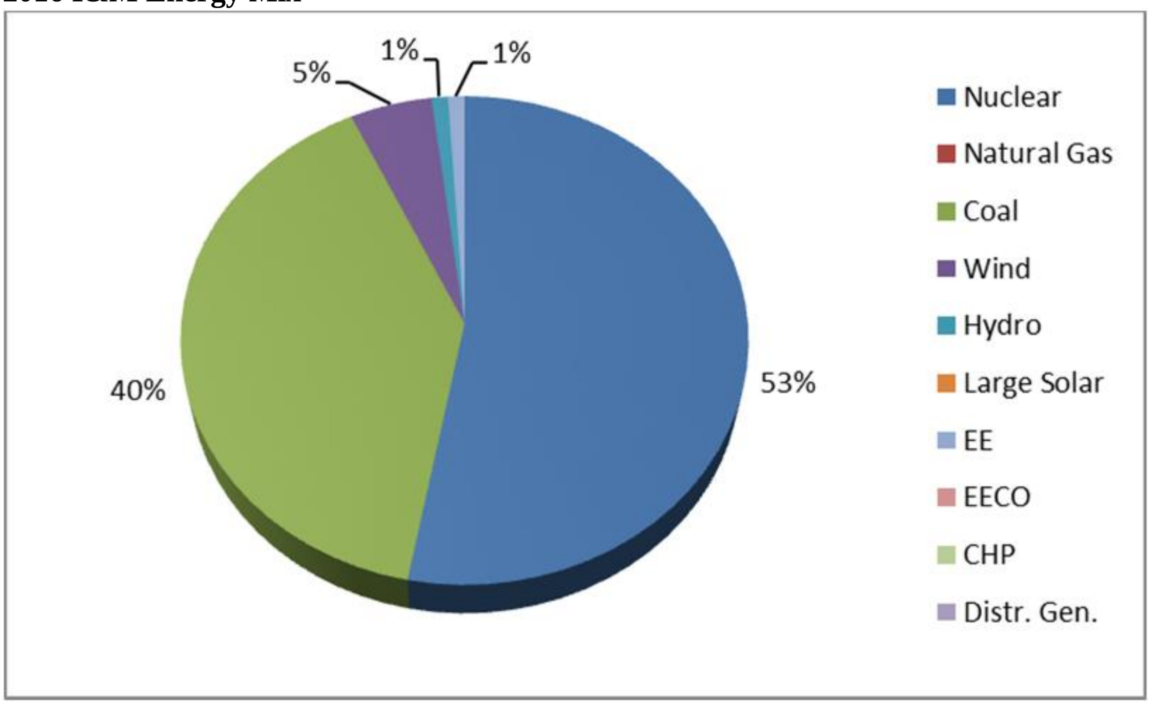
Cause No. 45564

I&M's Preferred Portfolio

- Maintains I&M's two units at Rockport Plant, including the addition of Selective Catalytic Reduction (SCR) systems in 2017 and 2019; as well as FGD systems in 2025 and 2028
- Continues operation of I&M's carbon free nuclear plant through, minimally, its current license extension period
- Add 600MW (nameplate) of large-scale solar resources
- Add 1,350MW (nameplate) of wind resources
- Adds 1,253MW of NGCC generation in 2035
- Implements end-use energy efficiency programs so as to reduce energy requirements by 914GWh and capacity requirements by 70MW in 2035
- Adds 27MW of natural gas CHP generation
- Recognizes additional distributed solar capacity will be added by I&M's customers, starting in 2016, and ramping up to 5MW (nameplate) by 2035

Source: Indiana Michigan Power 2015 IRP. Pg. ES-6

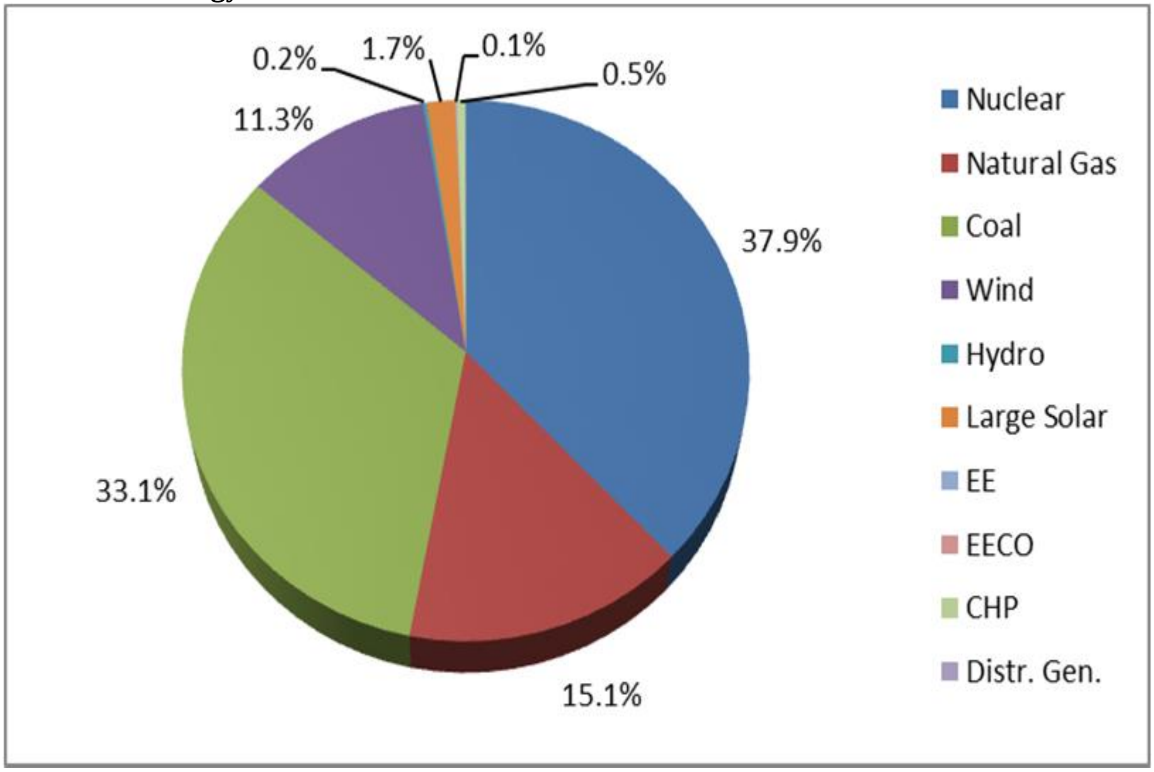
2016 I&M Energy Mix



Source: Indiana Michigan Power 2015 IRP. Pg. ES-10

Cause No. 45564

2035 I&M Energy Mix



Source: Indiana Michigan Power 2015 IRP. Pg. ES-10

Energy efficiency and demand response is projected in the 2015 IRP to reduce I&M's retail load by 8 percent over the 2016-2035 planning horizon. (Page 50). In addition, DSM programs implemented by I&M in 2015-2018 were expected to result in 37 MW of reduced demand.

I&M's 2018 IRP is being developed with a target completion date of November 1, 2018. I&M is planning to thoroughly review the potential for terminating the Rockport Unit 2 contract as early as 2023 and the closing of Rockport Unit 1 by 2028. Numerous factors are driving exploration of these options including economics, legal, and regulatory considerations. It is important to keep in mind that the analysis is not complete and many factors will be considered prior to any decisions being made.

d) Indiana Municipal Power Agency – 2017 IRP

IMPA anticipates a need for market purchases through 2025 to provide a small amount of capacity and energy needed due to the expiration of a 100 MW purchase power agreement in 2021. From 2018 through 2027, IMPA anticipates much of its new resources will be solar and wind. After 2026, IMPA expects to have adequate resources with the addition of one or more combined cycle units. The following graphics show IMPA's resource needs and the resources required to serve its member cities' electrical requirements.

Cause No. 45564

IMPA Future Resource Changes

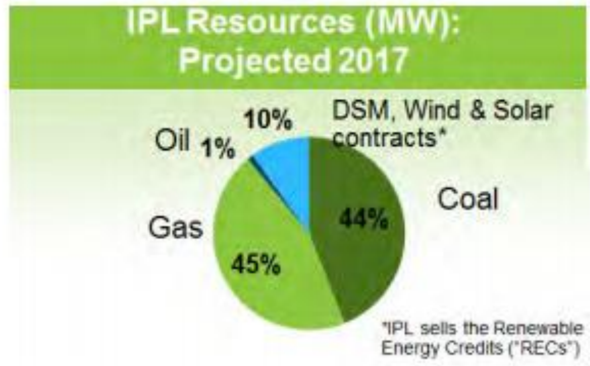
Year	Capacity Losses MW Lost	Resource	Capacity Additions MW Added	Resource	Net MW
2018	(50)	PPA Expires	12 100	Solar Bilateral Capacity (18-20)	62
2019	(50)	Wind PPA Expires	12 50	Solar Wind PPA	12
2020			12	Solar	12
2021	(100) (100)	PPA Expires Bilateral Capacity Expires	12 200	Solar Bilateral Capacity (21-25)	12
2022			12	Solar	12
2023			12	Solar	12
2024			12	Solar	12
2025			12	Solar	12
2026	(90) (200)	WWVS Retires Bilateral Capacity Expires	12 200 50	Solar Advanced CC Wind PPA	(28)
2027			12	Solar	12
2028			12	Solar	12
2029					
2030					
2031					
2032					
2033					
2034	(190)	PPA Expires	260	Advanced CC	70
2035					
2036					
2037					
Total	(780)		992		212

Source: Indiana Municipal Power Association 2017 IRP. Pg. 1-13

e) Indianapolis Power & Light Company – 2016 IRP

IPL retired 260 MW of coal-fired generation in 2015 and 2016, converted 630 MW of coal-fired generation to gas the spring of 2015, and completed the 671 MW Eagle Valley Combined Cycle Gas Turbine (CCGT) on April 28, 2018. The following table shows how IPL's resource mix changed over the period 2007-2017.

Cause No. 45564



Source: Indianapolis Power & Light 2016 IRP. Pg. 3

In the IRP, IPL embraced flexibility for future resources:

> Optionality will take us many places, but at its core, an option is what makes you antifragile and allows you to benefit from the positive side of uncertainty, without a corresponding serious harm from the negative side (Page 2).
>
> IPL has been a leader in Indiana in taking steps to change its portfolio, moving toward cleaner resource options through offering Demand Side Management ("DSM") programs, replacing coal-fired generation with natural gas-fired generation, securing wind and solar long-term contracts known as Purchased Power Agreements ("PPAs"), and building the first battery energy storage system in the Midcontinent Independent System Operator's ("MISO's") region. IPL plans to continue this transition proactively while simultaneously maintaining high reliability and affordable rates (Page 1).

In the 2016 IRP, IPL contended, given the information available in 2015 and 2016, the *hybrid preferred resource portfolio* in the last column is a more appropriate solution. IPL cited technology costs that may decrease more quickly than currently projected, which would likely drive changes in renewable and distributed generation penetration (Page 9). The below table details the four primary scenarios that were considered by IPL.

Cause No. 45564

IPL Summary of IRP Scenarios and Potential Future Resources

	Final Base Case	Strengthened Environmental	Distributed Generation	Hybrid
Coal	1078	0	1078	1078
Natural Gas	1565	2732	1565	1565
Petroleum	11	11	11	0
DSM and DR	208	218	208	212
Solar	196	645	352	398
Wind with ES*	1300	4400	2830	1300
Battery	500	0	50	283
CHP	0	0	225	225
totals	4858	8006	6319	5060

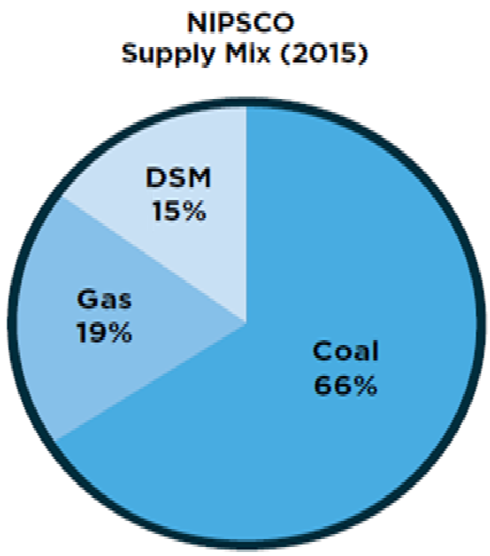
It should also be noted that IPL has been a leader in the deployment of Advanced Metering Infrastructure (AMI) that provides IPL with customers' sub-hourly usage information. This very discrete data can be used to enhance the credibility of IPL's load forecasting. Opportunities to establish more precise rates that recognize the cost of providing electricity vary continuously and aid in the evaluation, measurement, and valuation (EM&V) of energy efficiency programs, demand response, distributed energy resources, and renewable resources. It enables IPL to evaluate non-utility resources on a more comparable basis to utility resources, provides information needed to integrate new technologies such Energy Storage (e.g., batteries) and Electric Vehicles (EV), and improves the information needed for distribution system planning which may result in improved distribution reliability.

f) Northern Indiana Public Service Company – 2016 IRP

NIPSCO's 2015 coal-fired generation accounted for 66 percent of its resource mix, which was a 24 percent decrease from 2010. Natural gas generation constituted 19 percent in 2015. DSM, particularly the industrial interruptible program, accounted for about 15 percent of the resource mix in 2015.

NIPSCO retired Bailly Generating Station ("Bailly") Units 7 and 8 in May 2018. The replacement capacity necessary to meet the customer demand during the short-term action plan period would range from approximately 150-200 MW and would be addressed with either short-term power purchase agreements and/or market capacity purchases, whichever provides the best alignment of costs and mitigation of risks for customers.

Cause No. 45564



Source: Northern Indiana Public Service Company 2016 IRP. Pg. 4

NIPSCO, in the 2018 IRP under development, issued an "all source Request for Proposals" as a means of securing future resources. According to NIPSCO in its September 2018 IRP stakeholder meeting, its IRP update suggests that all four Schahfer units may be retired by year-end 2023 due to being uneconomic in the current wholesale power market. The IRP also indicates that Michigan City may be retired in 2028 for economic reasons. The preliminary plan is for the retired capacity to be replaced by a combination of renewables based on a competitive bidding process.

g) Southern Indiana Gas & Electric Company – 2016 IRP

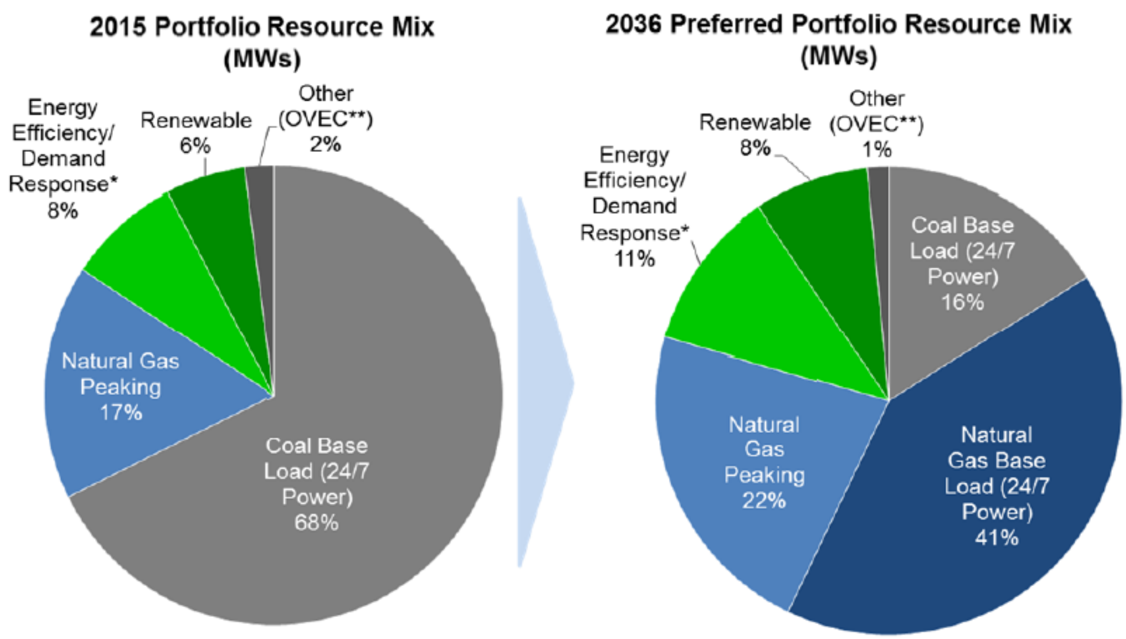
SIGECO's current generation mix consists of approximately 1,360 MW of installed capacity. This capacity consists of approximately 1,000 MW of coal fired generation (68 percent), 245 MW of gas-fired generation, 3 MW of landfill gas generation, 80 MW of wind from power purchase agreements, and a 1.5 percent ownership share of Ohio Valley Electric Corporation (OVEC), which equates to 32 MW. SIGECO's preferred resource plan would have the mix of natural gas and coal essentially swapping places in its generation resource mix. Natural gas would end the 20 year planning period at 63 percent of the resource portfolio, and coal would account for 16 percent. The small difference is made up through small increases in energy efficiency and renewable resources.

SIGECO noted on page 9 of the Non-Technical Summary that the cost of renewable resources continue to decline but are still expected to be more expensive in the Midwest over the next several years. SIGECO also expressed the concern that they need to learn more about integrating solar resources in its territory:

> Based on the IRP planning process, SIGECO has selected a preferred portfolio plan that balances the energy mix for its generation portfolio with the addition of a new combined cycle gas turbine facility and solar power plants and significantly reduces its reliance on coal-fired electric generation. SIGECO's preferred portfolio reduces its cost of providing

Cause No. 45564

service to customers over the next 20 years by approximately $60 million as compared to continuing with its existing generation fleet… SIGECO will continue to evaluate its preferred portfolio plan in future IRPs to ensure it remains the best option to meet customer needs (Page 2 and graph on page 5).



Source: Southern Indiana Gas & Electric Company 2016 IRP. Pg. 46

SIGECO is proposing in Cause No. 45052 to diversify its generation fleet based on its 2016 Integrated Resource Plan by investing in a new CCGT sized to replace certain coal-fired units that will be retired at the end of 2023. SIGECO is seeking a CPCN to construct a 2x1 F-class technology CCGT with capacity of 800 to 900 MW, to be constructed on the ground adjacent to SIGECO's Brown Generating Station.

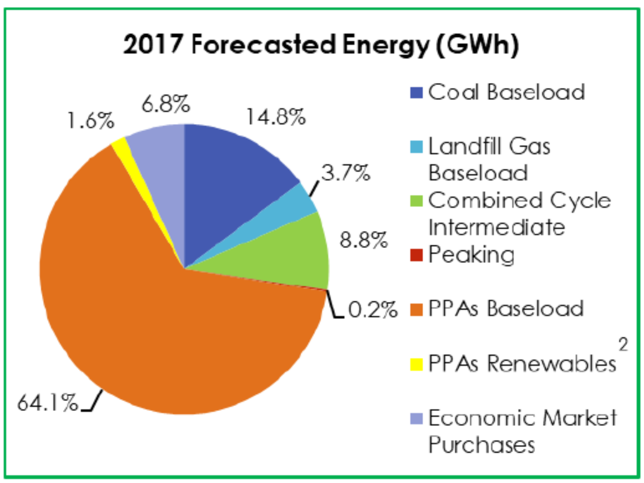
Consistent with the 2016 IRP, SIGECO plans to retire Culley Unit 2 and the Brown Units 1 and 2 once the CCGT is operational. According to SIGECO Culley Unit 2's age and efficiency will not justify further capital investment to allow it to continue to operate in the future. Brown Units 1 and 2 would require significant capital investment, including construction of a new scrubber, to allow them to continue to operate in the future. While SIGECO has agreed to continue its joint operation of Warrick Unit 4 through December 31, 2023, the continued operation of that unit is not economic and is further complicated because ALCOA, following its recent organizational and operational changes, is not able to unconditionally commit to use of the jointly owned unit as part of its future operations. Based on the 2016 IRP and updated IRP modeling completed in 2017, SIGECO plans to retire 73 percent of its current coal-fired generation fleet and diversify its generation portfolio by adding the CCGT at the end of 2023.

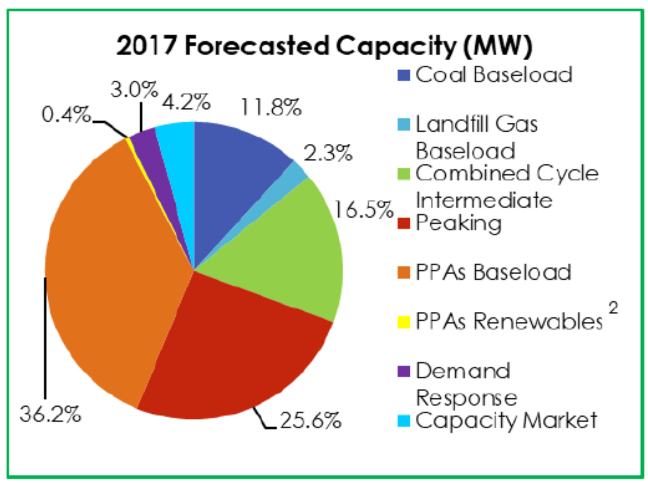
Cause No. 45564

h) Wabash Valley Power Association – 2017 IRP

From 2018 to 2020, Wabash Valley expects to meet its incremental capacity needs primarily by purchasing capacity through MISO's capacity auctions or bilateral transactions. After 2020, Wabash Valley will seek a resource mix that closely aligns with its average load factor of approximately 55-65 percent. That is, Wabash Valley plans to attain a power supply resource ratio of approximately 60 percent baseload/intermediate capacity to 40 percent peaking capacity with a move toward a greater percentage of natural gas units (e.g. combined cycle gas turbines and peaking plants) (Page 5).

Wabash Valley will purchase output from three wind projects from 2018 to 2020. Wabash Valley members will continue to run and enhance its energy efficiency programs and may choose to continue to build demand response resources in the near term. Past 2020, Wabash Valley's resource plan anticipates building 600 MW of baseload combined cycle resources and 350 MW of peaking combustion turbine resources along with 50 MW of energy efficiency. The expiration of existing power purchase agreements drives the need for these resources. At the end of the 20-year plan horizon in 2036, Wabash Valley's current base expansion plan forecasts that its energy and capacity needs will be served as depicted in the following charts.

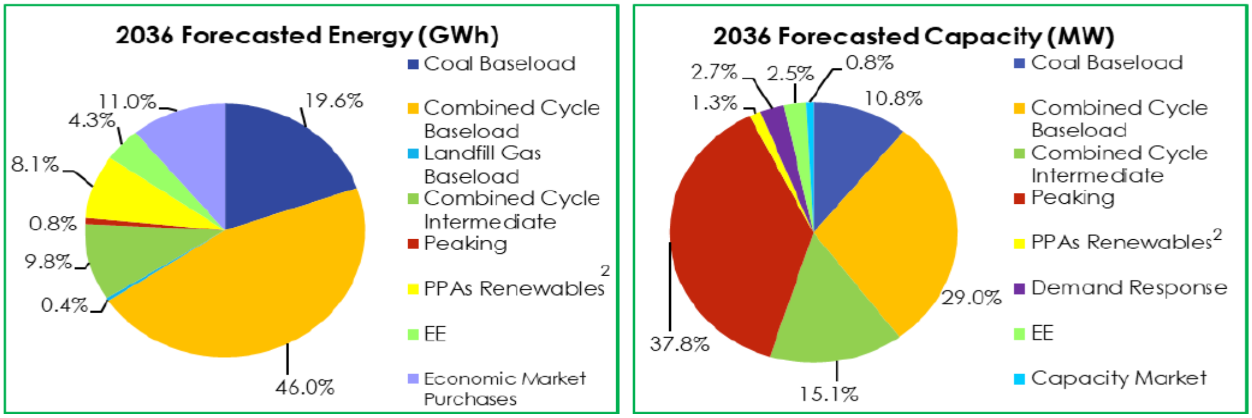




Source: Wabash Valley Power Association 2017 IRP. ES-Page 3

Cause No. 45564

2036 Resources[1]



Source: Wabash Valley Power Association 2017 IRP. ES-Page 7

Each year, Wabash Valley works with its Members to evaluate the power supply environment and to determine how to incorporate demand response programs into the overall power supply portfolio. Demand response programs continue to be an integral part of Wabash Valley's power supply portfolio with the primary purpose to keep power supply costs as low as possible. The company now approaches demand response programs as a resource, just like a peaking plant. (Page 24.)

In 2011, Wabash Valley created two rate riders that allowed end use commercial and industrial customers the ability to participate in MISO's Emergency Demand Response Initiative and PJM's Emergency Load Response Program. Since 2012, Wabash Valley has offered the PowerShift® program, an updated Direct Load Control program. To date, 19 of the 23 Members have signed agreements to participate in the PowerShift® program. The PowerShift® program includes participants' water heaters, air conditioners, pool pumps, field irrigators, entire homes, ditch pumps, and grain dryers. Please see the table below for details as of June 1, 2017. (Page 23 of IRP.)

Wabash Valley started offering energy efficiency programs to its member cooperatives in 2008 with the Touchstone Energy® Home Program, a residential new construction program focused on helping builders and homeowners construct a high performance, comfortable, durable, and low energy cost home. Since 2008, the company has worked jointly with member cooperatives, retail members and power supply staff to develop attainable savings goals that lessen baseload power supply costs and increase retail member satisfaction throughout its service territory (Page 27). In Wabash Valley's 2017 IRP, the generation and transmission cooperative (G&T) said its members realized the following savings from energy efficiency. (Page 21.)

Cause No. 45564

Energy Efficiency MWh Savings 2010-2017

Wabash Valley EE Savings (MWh)								
	2010	2011	2012	2013	1/2014 – 6/2015	7/1/2015 – 3/31/2016	4/2016 – 12/2016	1/2017 – 12/2017 (As of 8/2017)
MWh Savings	5,043	4,898	13,579	22,717	27,330	23,488	64,604	25,192
					Verified	Verified	Verified	Goal: 34,277

Source: Wabash Valley Power Association 2017 IRP. Pg. 31

Energy Efficiency Cumulative Program Highlights 2008-2017 (As of 8/2017)

Cumulative Program Highlights	
Residential Member Participants	41,481
C&I Member Participants	1,312
Total Amount of Incentives Paid	$14,299,000
Avoided Power Supply Cost @ $40/MWh	$17,268,000

The savings goal for 2017 is 34,277 MWh.

Source: Wabash Valley Power Association 2017 IRP. Pg. 31

2. Renewable Resources in Resource Mix

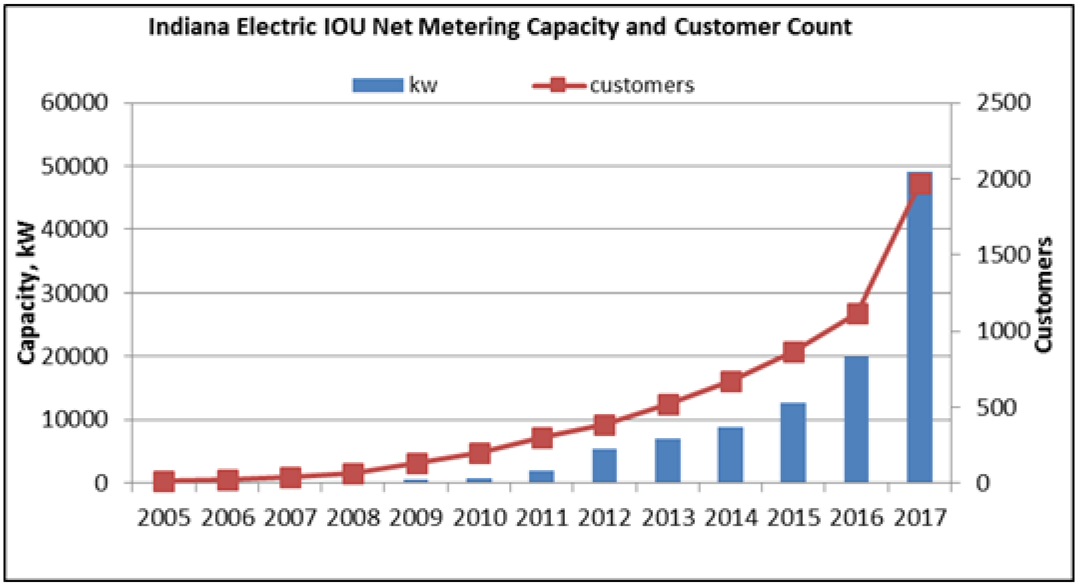
Indiana utilities' resource mix show an increase in renewable resources, particularly wind. As the growth rate of wind and solar has been significant, the total amount of renewable resources, as a percent of all resources in Indiana is still very small but an increasing part of utility resource portfolios.

The total amount of installed wind capacity in Indiana is about 2,114 MW. This constitutes about 85 percent of all renewable installed resource capacity in Indiana. Much of this power is sold out of state. The amount of wind power under purchase power agreements by Indiana utilities is about 1,098 MW with about 301 MW purchased from out-of-state wind generators. As of May 2018, Indiana utilities have about 797 MW of power purchased agreements for wind. Based on the IRPs, total wind resources are expected to grow as utilities build or contract for utility-scale wind resources as indicated in their most recent IRPs.

Net metering allows customers with small renewable facilities to receive a credit for excess electricity produced at the retail rate. As the following graph demonstrates, net metering has grown significantly, especially in terms of number of customers, but provides only a small percentage of the generation capacity in Indiana. In 2017, SEA 309 became law, limiting how long eligible customers could qualify for net metering and created a new compensation rate when net metering will no longer be available. The 2017 increase in both customer participation and

Cause No. 45564

net metering capacity is likely due to the new legislation, which created a cutoff date for being grandfathered in.



Another option for renewable resources is the Feed-in-Tariff or FIT [4]. However, as evidenced by the table below, this has a very limited application in Indiana. New customers cannot join IPL's FIT, and NIPSCO's FIT is available until participation limits are reached.

Summary of Resources Participating in the Feed-In-Tariff Option

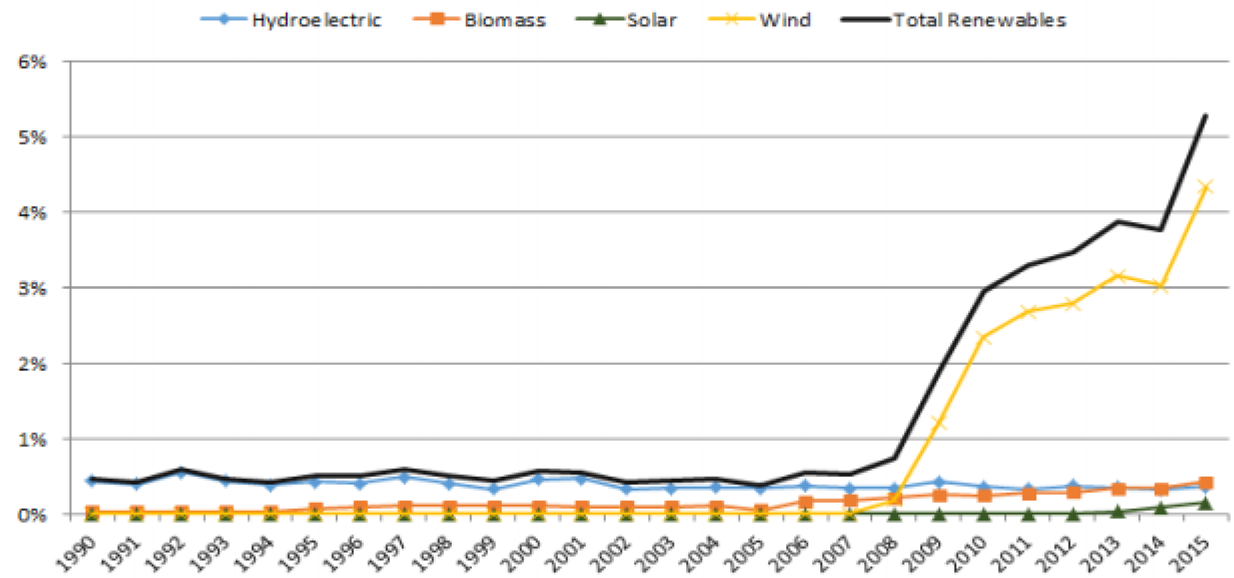
	Wind (kW)	Photovoltaic (kW)	Biomass (kW)	Total (kW)
IPL	0	94,384	0	94,384
NIPSCO	180	16,488	14,348	31,016
Total	**180**	**110,872**	**14,348**	**125,400**

The following graph illustrates the rapid growth in wind generation in Indiana as a share of the total electricity generation in the state through 2015. It should be noted this graph includes energy for total wind energy generated in Indiana, not just the energy from Indiana wind facilities with long-term power purchase contracts with Indiana utilities. Despite the rapid growth in solar, it contributes a very small share to the total electricity generated in Indiana.

[4] A FIT is a policy tool designed to encourage the development of renewable electricity generation by typically offering above market prices for output as well as the assurance that the utility will purchase the output. FITs are typically designed for small-scale renewable energy technologies that use solar, wind, and/or biomass.

Cause No. 45564

Renewables share of Indiana electricity generation (1960-2014) EIA May 2017



Utilities expect roof top and utility-scale solar resources to increase (this includes Community Solar and concentrated photovoltaic).

Percent of Solar Total 1 MW and Larger		
Utility	**MW**	**Percent**
IPL	**91.94**	**46.8%**
IMPA	**39.10**	**19.9%**
Duke	**37.25**	**18.9%**
Hoosier	**11.84**	**6.0%**
NIPSCO	**11.50**	**5.8%**
IM	**5.00**	**2.5%**
WVPA	**-**	**0.0%**
Vectren	**-**	**0.0%**
Total	**196.63**	

In addition, there is an expectation that distributed energy resources (DERs), including Combined Heat and Power, as well as battery and other storage technologies, will increase their penetration over the 20 year planning horizon, which could be used to improve the reliable capacity of renewable resources. Newer technologies (such as fuel cells) may become economically feasible in the long run. In the short term, uncertainty about tax incentives may hinder growth in some technologies. In the longer run, several projections suggest that increases in efficiency, combined with coupling intermittent technologies with back-up generation or storage, will overcome the cost-effectiveness hurdle. Based on the IRPs, Indiana's utilities are expecting DERs to be an increasing factor in future years.

Cause No. 45564

3. Energy Efficiency and Demand Response

Collectively referred to as Demand Side Management (DSM), energy efficiency and demand response have a relatively small but important percentage of the total resource mix. The level of energy efficiency savings achieved by a utility in a year generally ranges from 0.7 percent to around one percent by those customers participating in energy efficiency programs. Energy efficiency also results in some demand reduction. According to the SUFG, demand response is expected to increase from about 1,000 MW to almost 1,200 MW over the 20-year forecast horizon (SUFG's 2017 Electricity Projections. Pg. 3-1). These resources add important resource diversity and reliability. That is, DSM reduces risks for the utility and customer. Moreover, in addition to lowering the cost to customers, these resources give customers greater control over their electric use and the attendant costs. As the sophistication and credibility of all aspects of the IRP evolve, it seems certain that these resources will be increasingly essential to the operations of the electric power system.

Under Indiana law, the five investor-owned electric utilities must submit three-year energy efficiency plans to be approved by the Commission. All five utilities have energy efficiency plans that have been approved by the Commission or are in the review process. One of the basic determinations required by the law is that the Commission must find that the proposed three-year energy efficiency plan is reasonably achievable, consistent with the utility's integrated resource plan, and designed to achieve an optimal balance of energy resources in the utility's service territory.

Hoosier Energy, IMPA, and WVPA are not required to submit three-year energy efficiency plans under state law, but each organization offers a spectrum of DSM programs to their customers.

The following graphs are from the SUFG's 2017 statewide load forecast report and shows their projection of the kW impact of energy efficiency programs and demand response programs implemented through 2016.

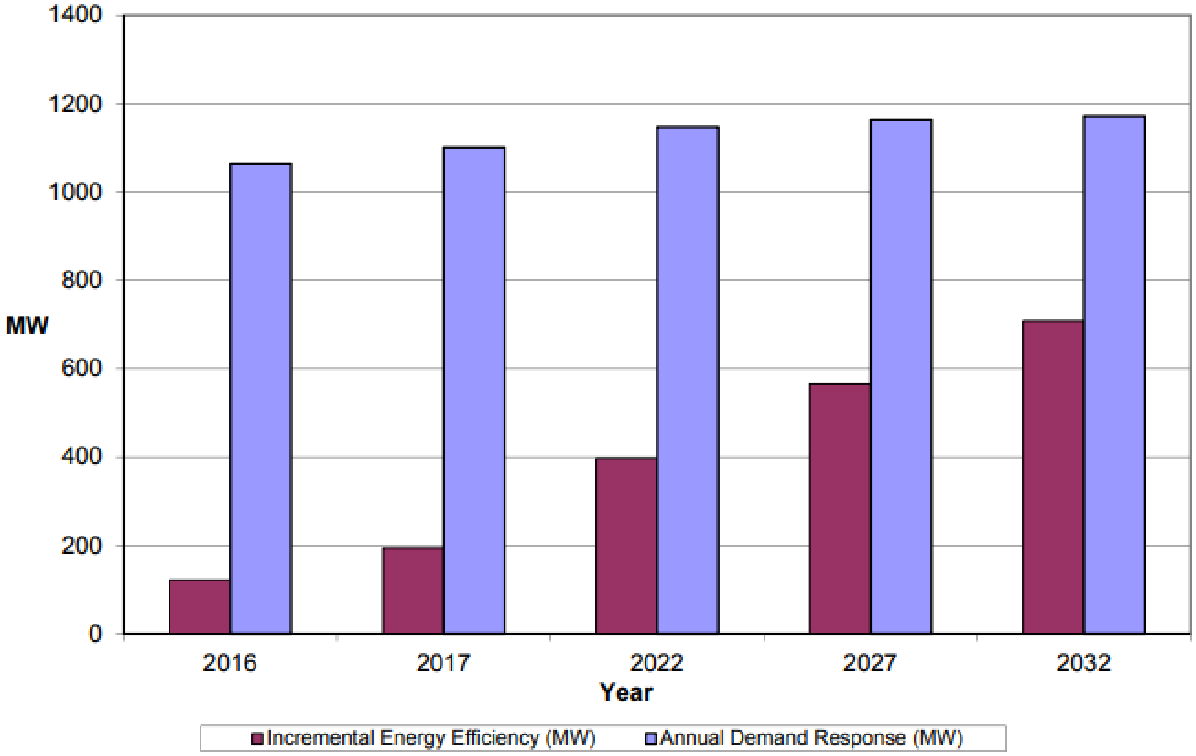
2015 Embedded DSM and 2016 Incremental Peak Demand Reductions from Energy Efficiency and Annual Demand Response Program (MW)

2015 Embedded DSM	2016 Incremental Energy Efficiency	2016 Annual Demand Response
3,421	121	1,063

Source: State Utility Forecasting Group's 2017 Electricity Projections. Pg. 4-5

Cause No. 45564

Projections of Incremental Peak Demand Reductions from Energy Efficiency and Demand Response



Source: State Utility Forecasting Group's 2017 Electricity Projections. Pg. 4-5

D. Resource and Operational Efficiencies Gained Through RTOs

With the reformation of the wholesale power markets in the late 1990s that resulted in the establishment of RTOs and Independent System Operators (ISOs) like MISO in Carmel, Indiana, and PJM, it became possible to efficiently trade power over great distances due to elimination of artificial anticompetitive barriers and pricing reform. This provided for more efficient and reliable operation of the electric system that tempered retail price increases. Today, all the large investor owned utilities with rates regulated by the Commission have joined, with Commission approval, an RTO. I&M is a member of PJM and the others (Duke, IPL, SIGECO, and NIPSCO) are members of MISO. Hoosier Energy is a member of MISO, and IMPA and WVPA are members of both RTOs given the dispersion of their members across the two RTOs. The following graphics illustrate the geographic scope of these RTOs.

Cause No. 45564

Fair and competitive access to a broadly diverse power supply meant that Indiana utilities no longer needed to plan their resources as if they were not interconnected to a vast and growing electrical grid. Understanding the current and future regional supply and demand for electric power is now an integral part of the Indiana IRP process.

Among other important functions, MISO and PJM facilitate the operations of the competitive wholesale power markets in a number of ways:

(1) Providing for regional control of generation resources that is much more cost effective than having individual utilities only use their own generation resources, which occurred before the RTOs.
(2) Transmission of electric power over vast distances, which is essential for reliability and the economic operation of the power system.
(3) A transmission planning process that allocates costs of new or upgraded transmission based on the principle that those that benefit pay their fair share of the costs.
(4) Increase in grid reliability, including assurances that utilities will have sufficient resources to meet their customers' needs even in unexpected circumstances.
(5) Informing their member utilities of the short- and long-term regional resource availability, which, in turn, enables Indiana utilities to alter their resource decisions to reduce costs for their customers and provide increased diversity of resources.

1. MISO Region

MISO's Value Proposition documents how the region benefits from its operation. In 2017, MISO calculated that its efforts provided between $2.9 billion and $3.7 billion in regional benefits, driven by enhanced reliability, more efficient use of the region's existing transmission and generation assets, and a reduced need for new assets. This collective, region-wide approach to grid planning and management delivers efficiencies that could not be achieved through statewide power pooling alone.

The MISO region is undergoing a significant change in the generating fleet composition. This is due to the cumulative cost effects of environmental controls, the aging of the coal and nuclear generating fleets, the greater than expected penetration of renewable resources due to declining

Cause No. 45564

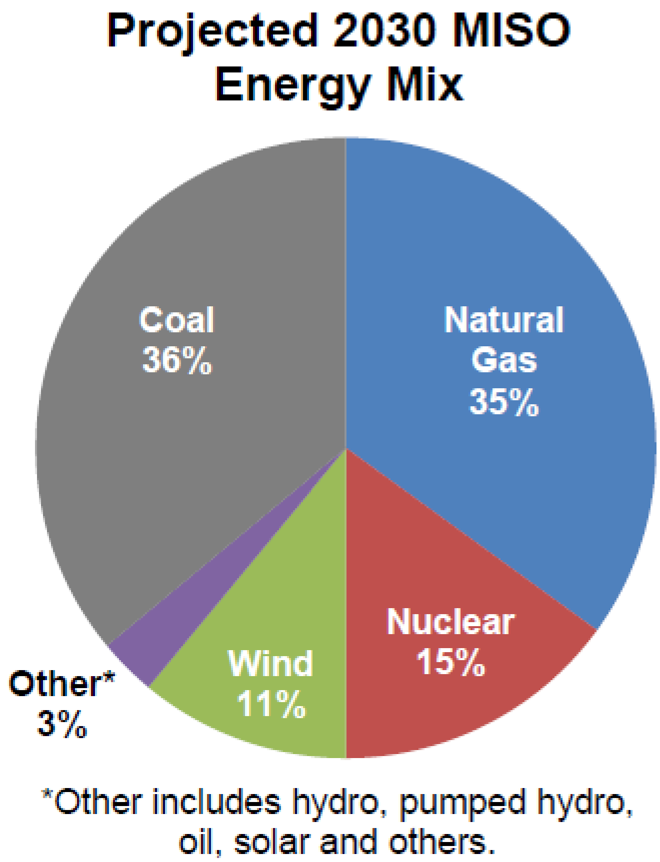
costs, declining cost of energy efficiency, and the declining cost of natural gas and projections for low natural gas prices for several years.

MISO had adequate electricity resources to meet demand for the 2018 summer. The regional transmission operator, whose grid covers 15 states in the Midwest and southern U.S., expects, beyond this summer and for the next several years, that it will satisfy the reliability requirements promulgated by the North American Electric Reliability Corporation and approved by the Federal Energy Regulatory Commission to assure adequate supply to satisfy the forecasted demand and meet unforeseen contingencies.[5]

Within the MISO region, coal-fired generation constituted 75 percent of total energy production in 2010 and is projected to decline to about 36 percent in 2030. From 2000 until April 2016, approximately 9.1 GW of coal-fired capacity has been retired in MISO, according to SNL. By 2030, natural gas-fired generation is projected to increase from 15 percent in 2014 to 35 percent in 2030. Increasingly, natural gas sets the market price (i.e., the Locational Marginal Price, or LMP). As the graphic below illustrates, the amount of gas-fired generation is expected to constitute 35 percent by 2030 compared to 36 percent for coal-fired power plants.

[5] Prior to RTOs, individual utilities were responsible for meeting their Resource Adequacy (RA includes adequate resources to meet expected needs and a *reserve margin* (RM) above the expected needs in the event of a contingency such as an unexpected outage at a large power plant). Reserve margins in excess of 20% were typical. The amount of reserve margins were based on a *rule of thumb* rather than rigorous analysis. With RTOs, the RA was based primarily on more rigorous mathmatical calcuations for the entire region. Setting RA for a large region afforded greater resource, fuel, and load diversity than was achievable by individual utilities. This reduced need for capacity due to RTO operations, results in savings for utilities and their customers. Generation resources located in the MISO region currently exceed the target level of RA. The current level of resources reflects the resource decisions made by the MISO market participants. These decisions are in reponse to a wide range of market forces and operational decisions besides the target level of RA set by the MISO on an annual basis.

Cause No. 45564



The majority of MISO states are traditionally regulated and the jurisdictional utilities are *vertically integrated.* Statutory authorities of most states in MISO require jurisdictional utilities to provide assurances to their respective regulatory commissions that they have adequate resources and plan to have sufficient resources to meet their customers' electric needs reliably and economically.

Despite the significant changes in generation resource composition and the anticipated changes as projected by MISO, the Midwest should have a well balanced portfolio of generation resources and technologies, thus avoiding undue reliance on any one technology or fuel type for the foreseeable future.

2. PJM Region

In contrast, PJM is characterized by predominately *restructured states* that have little, if any, regulatory authority over the operation, construction, and planning of generating resources. As a result, generation owners in those states are subject to market prices for economic viability. With the sharp decline in natural gas prices, projections for continued low-cost natural gas, and the relatively high capital cost of coal-fired (and nuclear) generating facilities, compared to natural gas generating facilities, a substantial amount of the coal-fired (and nuclear generation) is

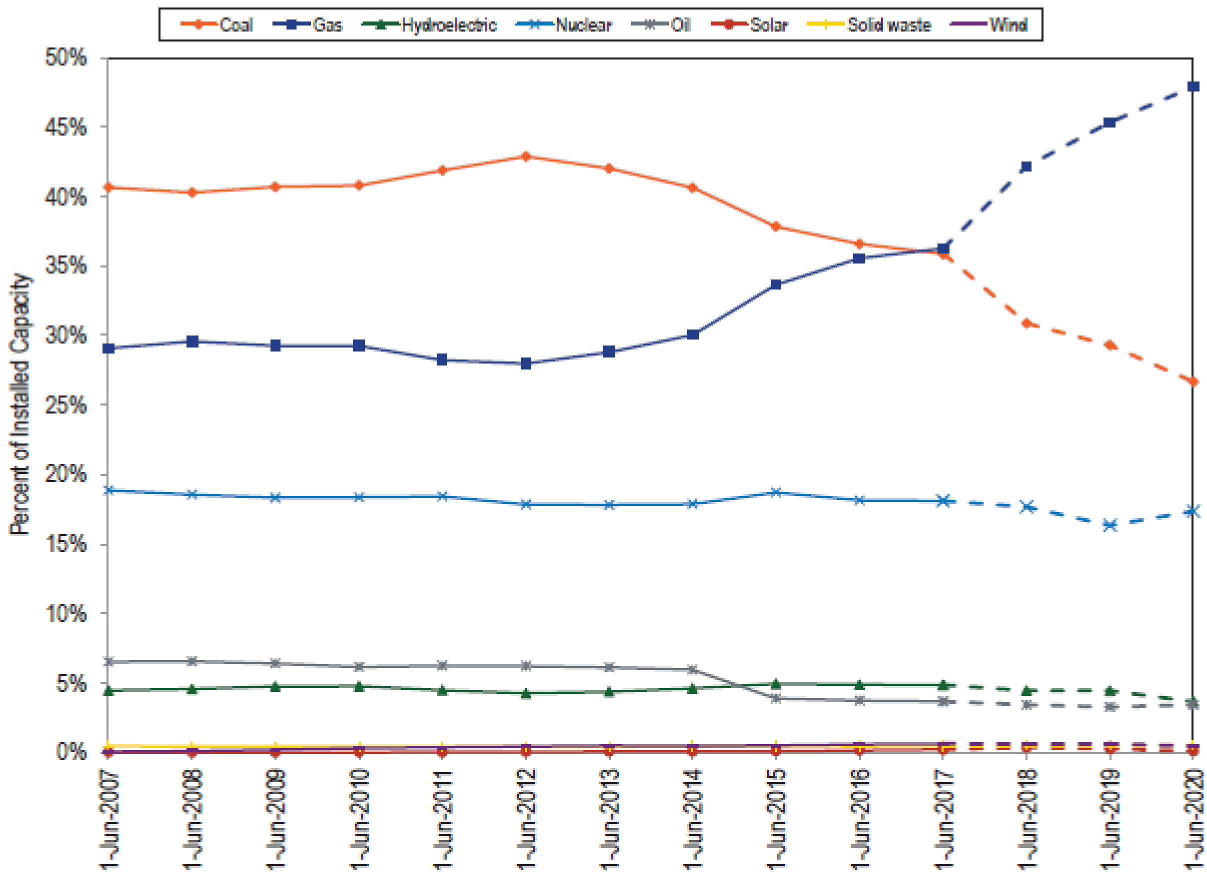
Cause No. 45564

at considerable risk for continued economic viability. As a result, some states have or are considering additional out-of-market actions to subsidize the operations of coal and nuclear power plants. These PJM market issues do not affect I&M or its parent company, American Electric Power (AEP), as they do not participate in PJM's capacity auction. Instead, AEP meets PJM's Fixed Resource Requirement (FRR), in which AEP assures that it has sufficient resources to more than meet its customers' needs.

Similar to MISO, PJM provides an annual value proposition, summarizing the benefit of a regional grid and market operations in ensuring reliability, providing the needed generating capacity and reserves, managing the output of generation resources to meet demand and procuring specialized services that protect grid stability. As with all RTOs, PJM reacts to changes in demand in real time, adjusting generation to be in balance with demand and maintain the transmission system at safe operating levels. PJM seeks to manage transmission constraints, limitations on the ability of the transmission system to move power, by adjusting the output of generators whenever possible to promote efficiency. PJM's large footprint makes the transmission planning process more effective by considering the region as a whole, rather than individual states. The fact that PJM plans for resource adequacy over a large region results in a lower reserve margin than otherwise would be necessary.

Like MISO, PJM is undergoing a significant change in the generating fleet composition. This is also due to the cumulative cost effects of environmental controls, the aging of the coal and nuclear generating fleets, the greater than expected penetration of renewable resources, declining cost of energy efficiency, and the declining cost of natural gas and projections for low natural gas prices for several years. Increasingly, DERs are expected to be a factor in future years.

The following graph shows the percentage of PJM installed capacity (by fuel source) for June 1, 2007 through June 1, 2020



Source: PJM State of the Market Report 2018, Monitoring Analytics. Section 5, Page 240.

PJM is also expected to meet their anticipated demand without major concerns. Beyond this summer and for the next several years, PJM expects to have sufficient resources to satisfy the reliability requirements promulgated by the North American Electric Reliability Corporation and approved by the Federal Energy Regulatory Commission to assure adequate supply to satisfy the forecasted demand and meet unforeseen contingencies.

E. Comparative Costs of Other Means of Meeting Future Needs

Integrated resource planning considers all possible resources, including traditional resources such as coal, natural gas, and nuclear, as well as energy efficiency, demand response, wind, solar, customer-owned combined heat and power, hydroelectric, and battery storage. An IRP considers all these resource options on a comparable basis as reasonably possible.

A useful first way of estimating and comparing the potential cost of new resources is to consider the Levelized Cost of Electricity (LCOE). LCOE represents the MWh cost (in discounted real dollars) of building and operating a generating plant over an assumed financial life of the facility. The LCOE includes capital costs, fuel costs, fixed and variable operations and maintenance costs, financing costs, and an assumed utilization rate for different types of resources. The

Cause No. 45564

importance of these factors varies among the technologies. For technologies such as solar and wind generation that have no fuel costs and relatively small variable O&M costs, LCOE changes in rough proportion to the estimated capital cost of generation capacity. The availability of various incentives, including state or federal tax credits (e.g., the Production Tax Credit for new wind, geothermal, and biomass and Investment Tax Credit for new solar photovoltaic and thermal plants), also affect the calculation of LCOE. For technologies with significant fuel cost, both fuel cost and overnight construction cost estimates significantly affect LCOE.

As with any cost factors forecast over a long period, 20 years for IRPs in Indiana, there is uncertainty about all of these factors, and their values can vary as technologies evolve and as fuel prices change. The projected utilization rate (e.g., capacity factor) depends on the forecasted demand for electricity and the existing resource mix in an area where additional capacity is to be added. For Indiana utilities, the expected RTO dispatch will affect the utilization rate. That is, the existing and projected comparison between resources in a region can directly affect the economic viability of those resources. The direct comparison of LCOE across technologies is, therefore, difficult and can be misleading as a method to assess the economic competitiveness of various generation alternatives. Still, in each IRP, the cost comparison over time of all resources is inherent in the modeling process. The IRP models go beyond an analysis of potential resource choices on the basis of LCOE by reflecting the value of different resource choices within the context of the utility and regional resource portfolio and how these portfolios might evolve over time. With this background, below is a table showing comparisons among different generating resources using the LCOE.

Cause No. 45564

Estimated Levelized Cost of Electricity (Capacity-Weighted Average) for New Generating Resources Entering Service in 2022 (2017 $/ MWh)

Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmission cost	Total system LCOE	Levelized tax credit[2]	Total LCOE including tax credit
Dispatchable technologies								
Coal with 30% CCS[3]	NB	NB	NB	NB	NB	NB	NA	NB
Coal with 90% CCS[3]	NB	NB	NB	NB	NB	NB	NA	NB
Conventional CC	87	13.0	1.5	32.8	1.0	48.3	NA	48.3
Advanced CC	87	15.5	1.3	30.3	1.1	48.1	NA	48.1
Advanced CC with CCS	NB	NB	NB	NB	NB	NB	NA	NB
Conventional CT	NB	NB	NB	NB	NB	NB	NA	NB
Advanced CT	30	22.7	2.6	51.3	2.9	79.5	NA	79.5
Advanced nuclear	90	67.0	12.9	9.3	0.9	90.1	NA	90.1
Geothermal	91	28.3	13.5	0.0	1.3	43.1	-2.8	40.3
Biomass	83	40.3	15.4	45.0	1.5	102.2	NA	102.2
Non-dispatchable technologies								
Wind, onshore	43	33.0	12.7	0.0	2.4	48.0	-11.1	37.0
Wind, offshore	45	102.6	20.0	0.0	2.0	124.6	-18.5	106.2
Solar PV[4]	33	48.2	7.5	0.0	3.3	59.1	-12.5	46.5
Solar thermal	NB	NB	NB	NB	NB	NB	NB	NB
Hydroelectric[5]	65	56.7	14.0	1.3	1.8	73.9	NA	73.9

Source: Energy Information Administration – Annual Energy Outlook 2018

1. Fuel Price Projections Influence Comparative Costs

As the SUFG stated:

> SUFG's current assumptions are based on the January 2017 projections produced by the Energy Information Administration (EIA) for the East North Central Region. SUFG's fossil fuel real price projections are as follows: Natural Gas Prices: Natural gas prices decreased significantly in 2009 relative to the high prices of 2008. Prices then rebounded somewhat in 2010 before declining again through 2012 before increasing back to 2010 levels by 2014. However, natural gas prices dropped again in 2015 to a level lower than that of 2012, followed by a slight decrease in 2016. They are projected to increase gradually for the remainder of the forecast horizon. Utility Price of Coal: Coal price projections are relatively flat in real terms throughout the entire forecast horizon as coal consumption decreases due to more natural gas and renewable generation observed in the electric power sector (Page 1-3).

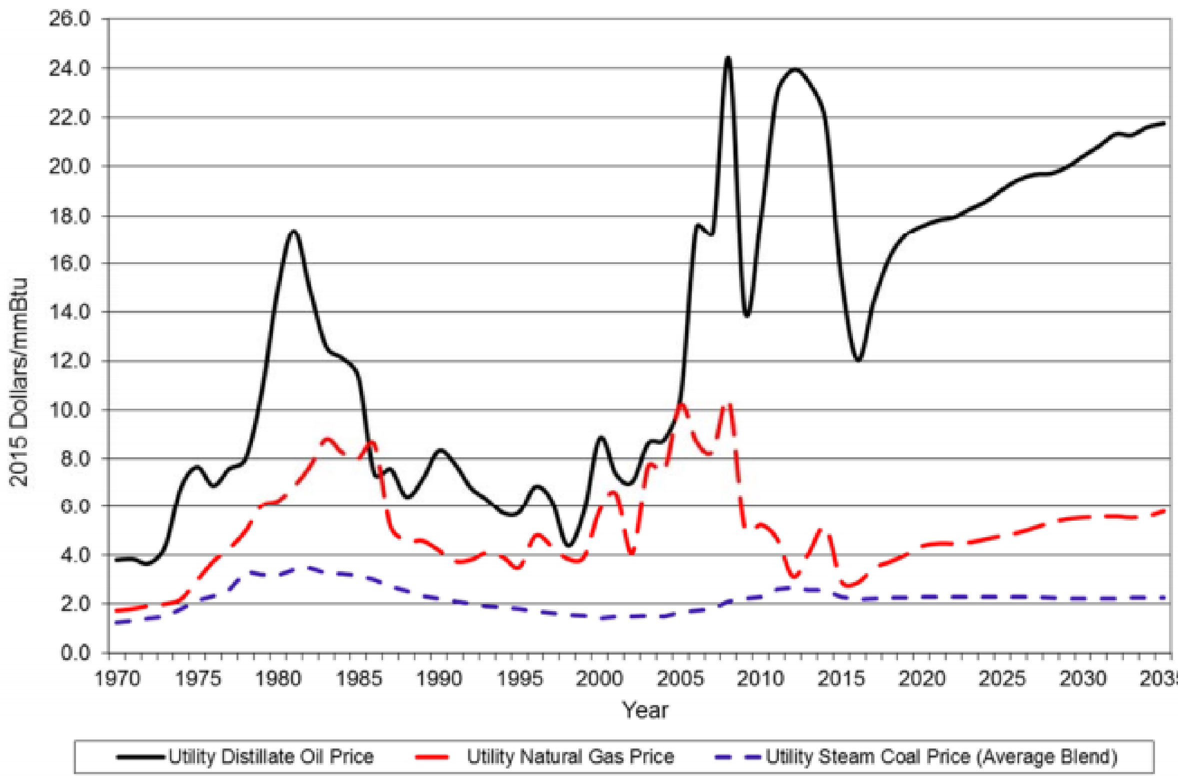
Similarly in the EIA's Annual Energy Outlook 2018, March 26, 2018:

> Future growth in U.S. crude oil and natural gas production is projected to be driven by the development of tight oil [1] and shale gas [2] resources. However, a great deal of

Cause No. 45564

uncertainty surrounds this result. In particular, future domestic tight oil and shale gas production depends on the quality of the resources, the evolution of technological and operational improvements to increase productivity per well and to reduce costs, and the market prices determined in a diverse market of producers and consumers, all of which are highly uncertain. [D]omestic dry natural gas production increases rapidly (more than 5% annually) through 2021 and then slows to an annual average growth rate of 1% through 2050, reaching 43.0 trillion cubic feet (Tcf) per year in 2050 in the Reference case.

Utility Real Fossil Fuel Prices



As noted by the SUFG:

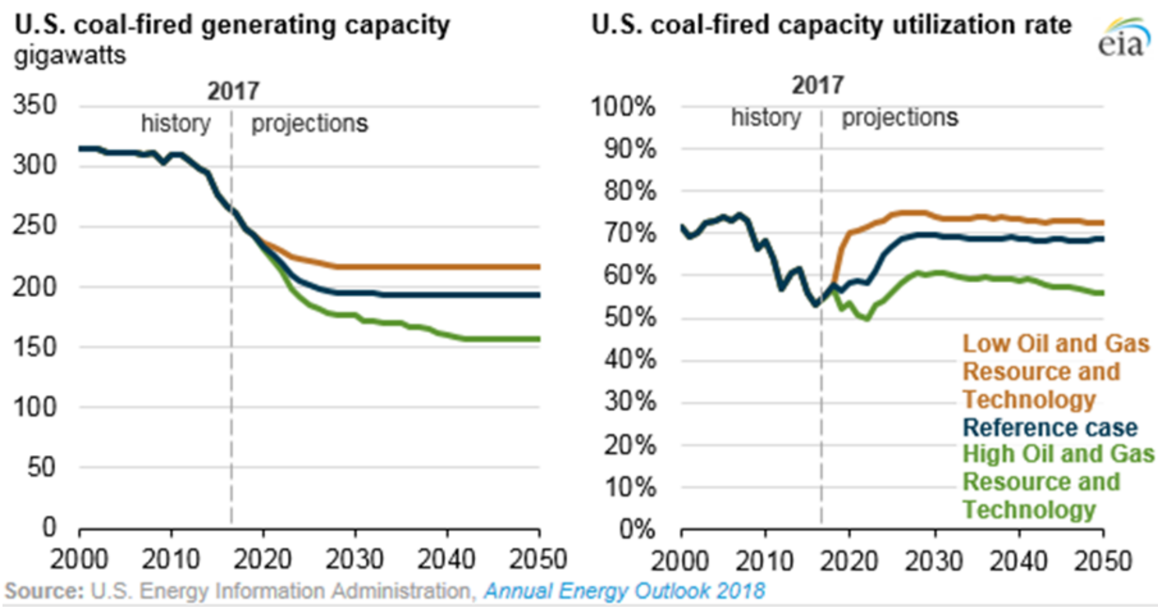
The prices of fossil fuels such as coal, natural gas and oil affect electricity demand in separate and opposing ways. To the extent that any of these fuels are used to generate electricity, they are a determinant of average electricity prices. Around 65% of electricity generation for Indiana consumers was fueled by coal in 2016. Thus, when coal prices increase, electricity prices in Indiana rise and electricity demand falls, all else being equal. On the other hand, fossil fuels compete directly with electricity to provide end-use services, i.e., space and water heating, process use, etc. When prices for these fuels increase, electricity becomes relatively more attractive and electricity demand tends to rise, all else being equal. As fossil fuel prices change, the impacts on electricity demand are somewhat offsetting. The net impact of these opposing forces depends on their

Cause No. 45564

impact on utility costs, the responsiveness of customer demand to electricity price changes and the availability and competitiveness of fossil fuels in the end-use services markets (SUFG page 4-3).

2. The Changing Fuel used in Generation Resources in the United States

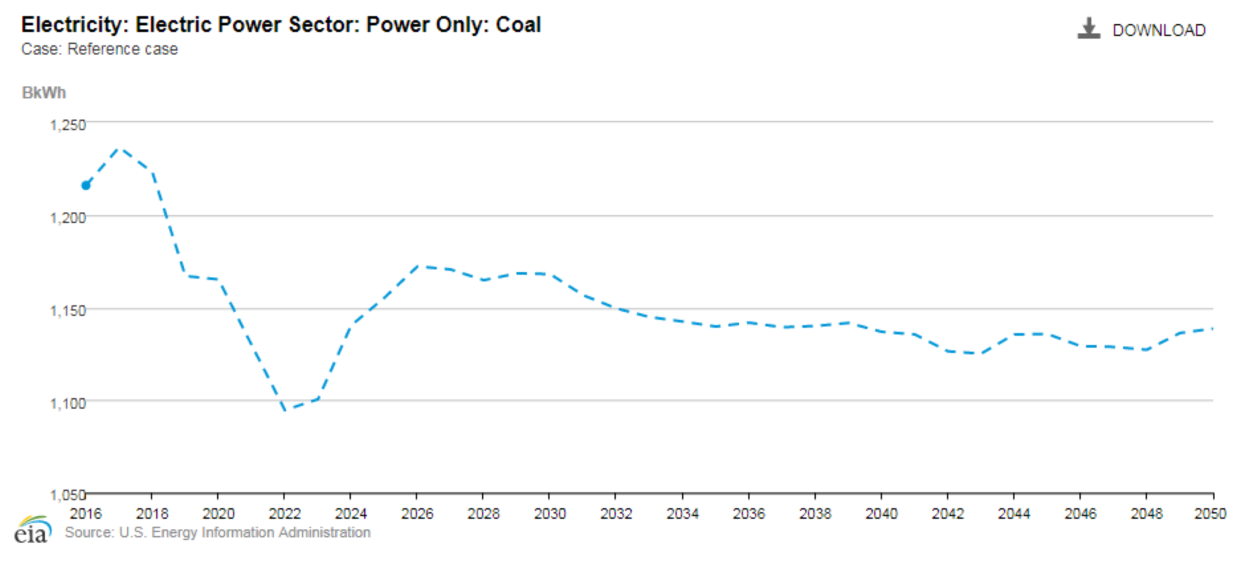
The following graphic prepared by the EIA projects three different scenarios or possible futures. Specifically, to better understand the potential risks, EIA constructed a "base case" (or "reference case" or "most expected case"), a high case that shows fewer coal retirements, and a lower case with more significant retirements of coal-fired generation. In these three potential outcomes, there are still significant decreases in the amount of coal-fired generating capacity in the United States in the first graph. In the second graph, while the utilization rate for coal-fired generation is lower than it was prior to the fracking boom, the remaining coal-fired power plants *may* have higher utilization rates than in the recent past, in large part depending on the price of natural gas relative to coal. In other words, the remaining coal-fired fleet may be run more in 2019 and beyond even though the aggregate amount of coal-fired generation will be diminished due to retirements. It is worth noting, however, that the low scenario shows a long-term decline in coal generation utilization (not being as frequently dispatched) if natural gas prices are lower than the base case projections.



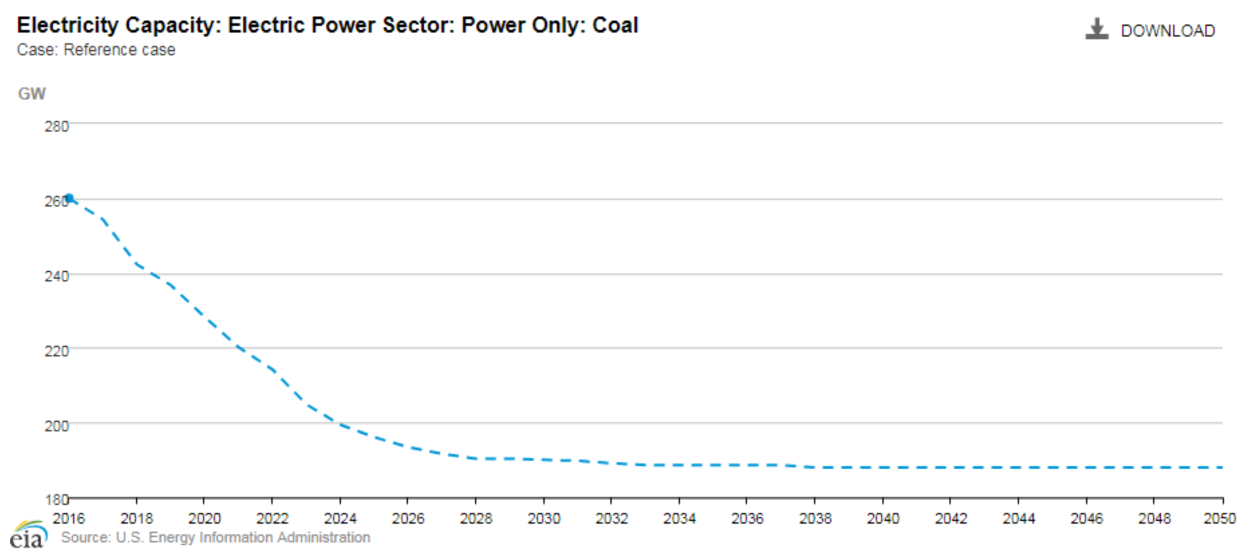
The following graph is EIA's Annual Energy Outlook 2018 reference case (or base case) showing the dynamics caused primarily by retirements of older and smaller coal-fired generating units and the continuing effect of environmental regulations. This graph is a projection of the change in baseload coal-fired generation (billion kWh) over the 2016-2050 planning horizon. While the production of electricity from coal-fired generation drops precipitously until 2022 the remaining coal-fired generating units shows a marked increase in projected output through 2026

Cause No. 45564

and a gradual decline thereafter due to the high cost of operating coal-fired generating facilities relative to the other resource alternatives. Of course, this scenario is just one of several possible future outcomes.

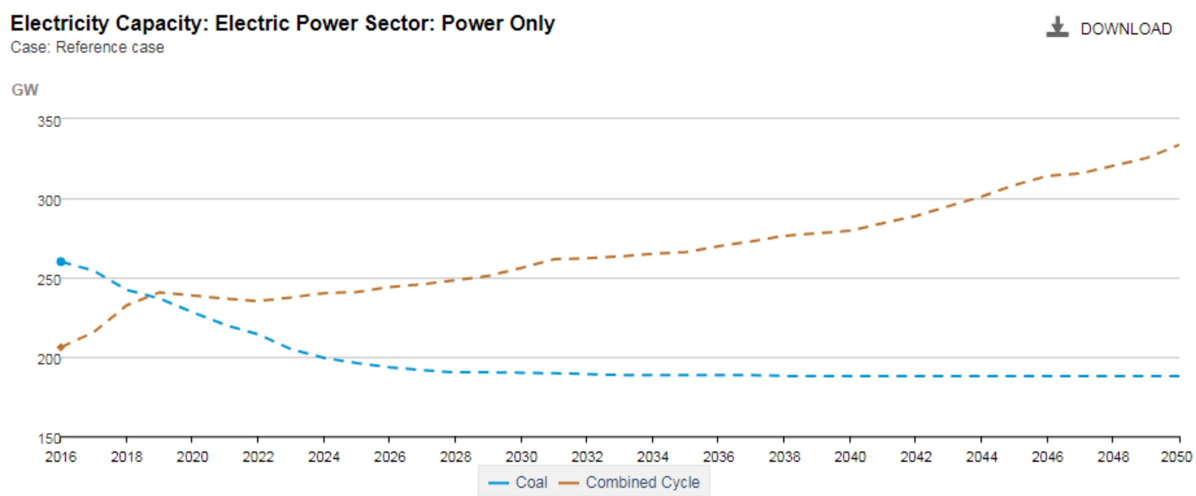


The following EIA "Reference Case" (or "Base Case") graph shows a precipitous decline in the amount of coal-fired capacity (in MW) of the entire 2016-2050 planning horizon. Subsequent graphs layer in other resources to show the relative changes in the nation's resource mix over the 2016-2050 planning horizon.



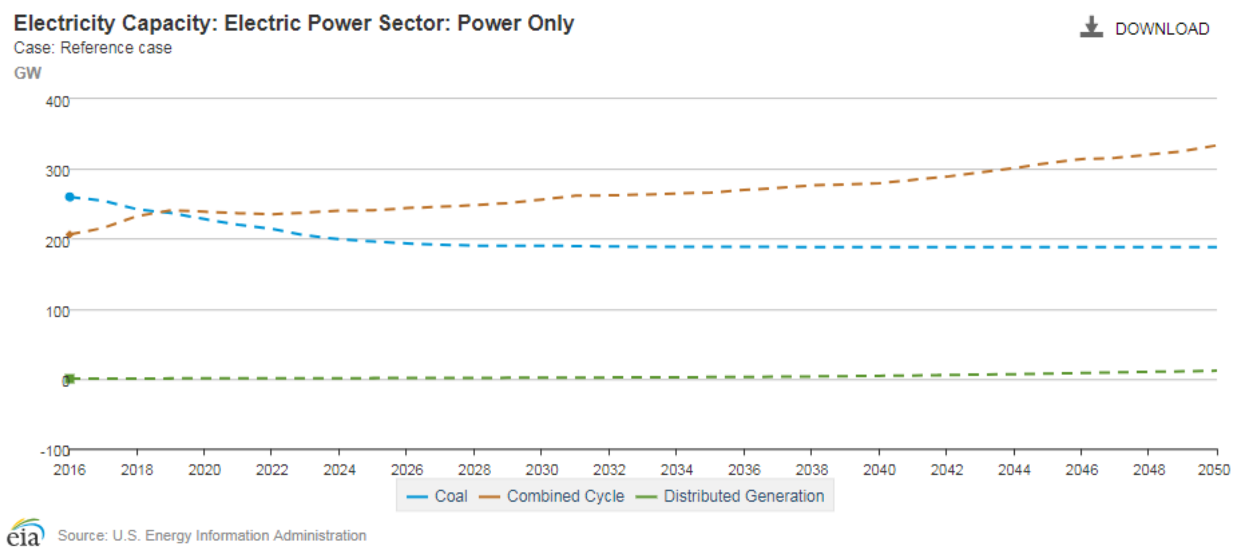
The graph below represents EIA's reference scenario to depict the projected increases in the capacities (MW) of natural gas combined cycle generation compared to coal-fired generation over the 2016-2050 planning horizon.

Cause No. 45564



The following graph depicts the EIA's reference case for the projected capacity (MW) supplied by several resources including coal, natural gas combined cycle, nuclear, and distributed generation.

Projections for Future Generation Capacity by Fuel Type for the U.S.



Cause No. 45564

F. Conclusion

The importance of well-developed and thoughtful long-term planning cannot be overstated given the long-lived nature of electric resource decisions and the extensive degree of uncertainty impacting the industry. The IRPs are intended to serve as objective guides for utilities, policymakers, and stakeholders to anticipate possible futures rather than a definitive plan of action. The credibility of the IRP analysis necessitates the use of state-of-the-art planning tools to construct a broad range of scenarios that reflect the dynamic nature of the environment for the electric utility industry. These scenarios, and the resulting resource portfolios, are intended to inform decision-makers of the risks and uncertainties inherent in the planning of future resources and the costs and benefits. The credibility of the analysis is critical to the efforts of Indiana utilities to maintain as many options as possible, which includes *off ramps,* to react quickly to changing circumstances and make appropriate changes in the resources.

Based on the 2015 through 2017 IRPs, the SUFG report, information from MISO, PJM, and the EIA, the expectation is that Indiana's electric needs, as well as the electric requirements of the region and the nation will increase gradually over the next 20 years. Due in large part to the likely retirement of additional coal-fired power plants, new resources (including traditional generation, energy efficiency, demand response, customer-owned resources / distributed energy resources, and new technologies) will be needed in the 2025-2035 timeframe. Indiana utilities' procurement of future resources and maintaining as many options as possible will be facilitated by MISO and PJM.

Cause No. 45564

IV. Appendices

APPENDIX 1
Cost and Performance Characteristics of New Central Station Electricity Generating Technologies
Overnight Construction Costs

Technology	First available year[1]	Size (MW)	Lead time (years)	Base overnight cost (2017 $/kW)	Project Contin-gency Factor[2]	Techno-logical Optimism Factor[3]	Total overnight cost[4,10] (2017 $/kW)	Variable O&M[5] (2017 $/MWh)	Fixed O&M (2017$/ kW/yr)	Heat rate[6] (Btu/kWh)	nth-of-a-kind heat rate (Btu/kWh)
Coal with 30% carbon sequestration (CCS)	2021	650	4	4,641	1.07	1.03	5,089	7.17	70.70	9,750	9,221
Coal with 90% CCS	2021	650	4	5,132	1.07	1.03	5,628	9.70	82.10	11,650	9,257
Conv Gas/Oil Combined Cycle (CC)	2020	702	3	935	1.05	1.00	982	3.54	11.11	6,600	6,350
Adv Gas/Oil CC	2020	429	3	1,026	1.08	1.00	1,108	2.02	10.10	6,300	6,200
Adv CC with CCS	2020	340	3	1,936	1.08	1.04	2,175	7.20	33.75	7,525	7,493
Conv Combustion Turbine[7]	2019	100	2	1,054	1.05	1.00	1,107	3.54	17.67	9,880	9,600
Adv Combustion Turbine	2019	237	2	648	1.05	1.00	680	10.81	6.87	9,800	8,550
Fuel Cells	2020	10	3	6,192	1.05	1.10	7,132	45.64	0.00	9,500	6,960
Adv Nuclear	2022	2,234	6	5,148	1.10	1.05	5,946	2.32	101.28	10,460	10,460
Distributed Generation - Base	2020	2	3	1,479	1.05	1.00	1,553	8.23	18.52	8,969	8,900
Distributed Generation - Peak	2019	1	2	1,777	1.05	1.00	1,866	8.23	18.52	9,961	9,880
Battery Storage	2018	30	1	2,067	1.05	1.00	2,170	7.12	35.60	N/A	N/A
Biomass	2021	50	4	3,584	1.07	1.00	3,837	5.58	112.15	13,500	13,500
Geothermal[8,9]	2021	50	4	2,615	1.05	1.00	2,746	0.00	119.87	9,271	9,271
MSW - Landfill Gas	2020	50	3	8,170	1.07	1.00	8,742	9.29	417.02	18,000	18,000
Conventional Hydropower[9]	2021	500	4	2,634	1.10	1.00	2,898	1.33	40.05	9,271	9,271
Wind	2020	100	3	1,548	1.07	1.00	1,657	0.00	47.47	9,271	9,271
Wind Offshore[8]	2021	400	4	4,694	1.10	1.25	6,454	0.00	78.56	9,271	9,271
Solar Thermal[8]	2020	100	3	3,952	1.07	1.00	4,228	0.00	71.41	9,271	9,271
Solar PV - tracking[8,11]	2019	150	2	2,004	1.05	1.00	2,105	0.00	22.02	9,271	9,271
Solar PV - fixed tilt[8,11]	2019	150	2	1,763	1.05	1.00	1,851	0.00	22.02	9,271	9,271

Source: Energy Information Administration – Annual Energy Outlook, April 2018

Cause No. 45564

APPENDIX 2
Coal Fleet Retirements

	Retired Coal Units Since 1-1-2010				
	Coal Unit (Year In-Service)	**Owner**	**Summer Rating (MW)**	**Retire Date**	**Age at Retire Date**
1	Edwardsport Unit 7 (1949)	Duke	45	01-01-10	61
2	Edwardsport Unit 8 (1951)	Duke	75	01-01-10	59
3	Mitchell Unit 5 (1959)	NIPSCO	125	09-01-10	51
4	Mitchell Unit 6 (1959)	NIPSCO	125	09-01-10	51
5	Gallagher Unit 1 (1959)	Duke	140	01-31-12	53
6	Gallagher Unit 3 (1960)	Duke	140	01-31-12	52
7	State Line Unit 1 (1929)	Merchant	197	01-31-12	83
8	State Line Unit 2 (1929)	Merchant	318	01-31-12	83
9	Ratts Unit 2 (1970)	Hoosier	121	12-31-14	44
10	Ratts Unit 1 (1970)	Hoosier	42	03-10-15	45
11	Tanners Creek Unit 1 (1951)	I&M	145	06-01-15	64
12	Tanners Creek Unit 2 (1952)	I&M	142	06-01-15	63
13	Tanners Creek Unit 3 (1953)	I&M	195	06-01-15	62
14	Tanners Creek Unit 4 (1956)	I&M	500	06-01-15	59
15	Eagle Valley 3 (1951)	IPL	40	04-15-16	65
16	Eagle Valley 4 (1953)	IPL	55	04-15-16	63
17	Eagle Valley 5 (1955)	IPL	61	04-15-16	61
18	Eagle Valley 6 (1956)	IPL	100	04-15-16	60
19	Wabash River Unit 2 (1953)	Duke	85	04-15-16	63
20	Wabash River Unit 3 (1954)	Duke	85	04-15-16	62
21	Wabash River Unit 4 (1955)	Duke	85	04-15-16	61
22	Wabash River Unit 5 (1956)	Duke	95	04-15-16	60
23	Wabash River Unit 6 (1968)	Duke	318	04-15-16	48
24	Bailly Unit 7 (1962)	NIPSCO	160	05-31-18	56
25	Bailly Unit 8 (1968)	NIPSCO	320	05-31-18	50

Cause No. 45564

Coal Fleet Changes Since 2010 - Total MW				
	Operating	**Retired**	**Total**	**Pct. Red.**
1-1-2010	18,018	---	18,018	---
1-1-2013	16,853	1,165	18,018	6.5%
8-23-2018	14,624	3,394	18,018	18.8%

Coal Fleet Changes Since 2010 - Number of Units				
	Operating	**Retired**	**Total**	**Pct. Red.**
1-1-2010	60	---	61	---
1-1-2013	53	8	61	13.1%
8-23-2018	36	25	61	41.0%

Conversions from Coal to Natural Gas			
Unit	**Owner**	**MW**	**Date**
Harding Street Unit 5 (1958)	IPL	97	12-31-15
Harding Street Unit 6 (1961)	IPL	97	12-31-15
Harding Street Unit 7 (1973)	IPL	421	06-01-16

TOTAL MW: 615

Cause No. 45564

APPENDIX 3
Coal Fleet Currently in Operation

	Coal Units in Operation - In State				
	Coal Unit	**Ownership**	**Summer Rating (MW)**	**Age in 2020**	**Year In-Service**
1	Edwardsport IGCC	Duke	595.0	8	2012
2	Rockport 2	Investor Group	1,300.0	31	1989
3	Petersburg 4	IPL	537.4	34	1986
4	Schafer 18	NIPSCO	361.0	34	1986
5	Brown 2	SIGECO	233.1	34	1986
6	Rockport 1	I&M	1,300.0	36	1984
7	Merom 1	Hoosier	501.0	37	1983
8	Schafer 17	NIPSCO	361.0	37	1983
9	Gibson 5	Duke, IMPA, WVPA	620.0	38	1982
10	Merom 2	Hoosier	482.0	38	1982
11	Gibson 4	Duke	622.0	41	1979
12	Schafer 15	NIPSCO	472.0	41	1979
13	Brown 1	SIGECO	227.8	41	1979
14	Gibson 3	Duke	630.0	42	1978
15	Petersburg 3	IPL	549.0	43	1977
16	Gibson 1	Duke	630.0	44	1976
17	Michigan City 12	NIPSCO	469.0	44	1976
18	Schafer 14	NIPSCO	431.0	44	1976
19	Gibson 2	Duke	630.0	45	1975
20	Culley 3	SIGECO	257.3	47	1973
21	Whitewater Valley 2	IMPA	60.0	47	1973
22	Cayuga 2	Duke	495.0	48	1972
23	Cayuga 1	Duke	500.0	50	1970
24	Warrick 4 (ALCOA)	SIGECO	134.8	50	1970
25	Petersburg 2	IPL	396.2	51	1969

Cause No. 45564

26	Petersburg 1	IPL	232.0	53	1967
27	Culley 2	SIGECO	88.3	54	1966
28	Gallagher 4	Duke	140.0	59	1961
29	Gallagher 2	Duke	140.0	62	1958
30	Whitewater Valley 1	IMPA	30.0	47	1973
31	Clifty Creek 1	Various	211.0	65	1955
32	Clifty Creek 2	Various	200.0	65	1955
33	Clifty Creek 3	Various	212.0	65	1955
34	Clifty Creek 4	Various	193.0	65	1955
35	Clifty Creek 5	Various	220.0	65	1955
36	Clifty Creek 6	Various	191.0	65	1955
Coal Units in Operation - Out of State					
	Prairie State 1	IMPA Share	103.0	8	2012
	Prairie State 2	IMPA Share	103.0	8	2012
	Prairie State 1	WVPA Share	41.5	8	2012
	Prairie State 2	WVPA Share	41.5	8	2012
	Trimble County 2	IMPA Share	96.0	9	2011
	Trimble County 1	IMPA Share	66.0	30	1990

Cause No. 45564

APPENDIX 4
Coal Units in Operation with Status Notes based on IRPs

	Coal Units in Operation - In State					
	Coal Unit	Ownership	Summer Rating (MW)	Age in 2020	Year In-Service	
1	Edwardsport IGCC	Duke	595.0	8	2012	
2	Rockport 2	Investor Group	1,300.0	31	1989	
3	Petersburg 4	IPL	537.4	34	1986	
4	Schafer 18	NIPSCO	361.0	34	1986	*NIPSCO's preliminary 2018 IRP update indicates unit retirement in 2023
5	Brown 2	SIGECO	233.1	34	1986	*Vectren plans to retire the unit on 12-31-23, Cause No. 45052 - pending
6	Rockport 1	I&M	1,300.0	36	1984	
7	Merom 1	Hoosier	501.0	37	1983	
8	Schafer 17	NIPSCO	361.0	37	1983	*NIPSCO's preliminary 2018 IRP update indicates unit retirement in 2023
9	Gibson 5	Duke, IMPA, WVPA	620.0	38	1982	
10	Merom 2	Hoosier	482.0	38	1982	
11	Gibson 4	Duke	622.0	41	1979	
12	Schafer 15	NIPSCO	472.0	41	1979	*NIPSCO's preliminary 2018 IRP update indicates unit retirement in 2023
13	Brown 1	SIGECO	227.8	41	1979	*Vectren plans to retire the unit on 12-31-23, Cause No. 45052 - pending
14	Gibson 3	Duke	630.0	42	1978	
15	Petersburg 3	IPL	549.0	43	1977	
16	Gibson 1	Duke	630.0	44	1976	
17	Michigan City 12	NIPSCO	469.0	44	1976	*NIPSCO's preliminary 2018 IRP update indicates unit retirement in 2028
18	Schafer 14	NIPSCO	431.0	44	1976	*NIPSCO's preliminary 2018 IRP update indicates unit retirement in 2023
19	Gibson 2	Duke	630.0	45	1975	
20	Culley 3	SIGECO	257.3	47	1973	*Vectren in CN 45052 requests $90M to make unit EPA compliant beyond 12-31-23 - pending
21	Whitewater Valley 2	IMPA	60.0	47	1973	
22	Cayuga 2	Duke	495.0	48	1972	
23	Cayuga 1	Duke	500.0	50	1970	
24	Warrick 4 (ALCOA)	SIGECO	134.8	50	1970	*Vectren plans to end the joint operating agreement with ALCOA on 12-31-23, CN 45052- pending
25	Petersburg 2	IPL	396.2	51	1969	
26	Petersburg 1	IPL	232.0	53	1967	
27	Culley 2	SIGECO	88.3	54	1966	*Vectren plans to retire the unit on 12-31-23, Cause Number 45052 - pending
28	Gallagher 4	Duke	140.0	59	1961	
29	Gallagher 2	Duke	140.0	62	1958	
30	Whitewater Valley 1	IMPA	30.0	47	1973	
31	Clifty Creek 1	Various	211.0	65	1955	
32	Clifty Creek 2	Various	200.0	65	1955	
33	Clifty Creek 3	Various	212.0	65	1955	
34	Clifty Creek 4	Various	193.0	65	1955	
35	Clifty Creek 5	Various	220.0	65	1955	
36	Clifty Creek 6	Various	191.0	65	1955	

Cause No. 45564

APPENDIX 5
Status of Indiana Wind Farms

Operating Indiana Wind Farms

IURC Cause No.	Wind Project	County	Nameplate Capacity (MW)	Completion Year
43068	Benton County Wind Farm	Benton	130.5	2008
43338	Fowler Ridge Wind Farm I	Benton	301.3	2009
43443	Fowler Ridge Wind Farm II-A	Benton	199.5	2009
43444	Fowler Ridge Wind Farm III	Benton	99.0	2009
43484	Hoosier Wind Farm	Benton	106.0	2009
43602	Meadow Lake Wind Farm I	White	199.7	2009
43678	Meadow Lake Wind Farm II	White	99.0	2010
43747	Meadow Lake Wind Farm III	White	110.4	2010
43758	Meadow Lake Wind Farm IV	White	98.7	2010
44044	Wildcat Wind Farm I	Madison/Tipton	200.0	2012
44358	Headwaters Wind Farm	Randolph	200.0	2014
44438	Fowler Ridge IV Wind Farm (Amazon)	Benton	150.0	2015
43876	Meadow Lake Wind Farm V	White	100.8	2017
44299	Bluff Point Wind Farm	Jay/Randolph	119.0	2017

TOTAL MW: 2,113.9

Indiana Wind Farms Under Construction

45010	Meadow Lake Wind Farm VI	White	200.4	2018
44978	Jordan Creek Wind Farm	Warren	400.0	2019

+TOTAL UNDER CONSTRUCTION IN 2018: 600.4

Indiana Wind Farms Approved - Construction Not Started

43781	Spartan Wind Farm	Newton	100.0	
45047	West Fork Wind Farm	Fayette	102.0	2019

+ TOTAL WITHOUT CONSTRUCTION START: 202.0

=TOTAL APPROVED WIND FARMS: 2916.3 MW

Cause No. 45564

APPENDIX 6
Wind Purchased Power Agreements by Indiana's Utilities

Wind Energy Power Purchase Agreements (PPAs) by Indiana Utilities			PPAs for Indiana Wind Only (in MW)								
Utility	**Wind Farm**	**Power Purchase Agreement (MW)**	**Total IN Only**	**NIPSCO**	**Duke**	**Vectren**	**I&M**	**IPL**	**IMPA**	**WVPA**	**Hoosier**
NIPSCO	Barton (IA)	50.0									
Duke Indiana	Benton County (IN)	110.7	110.7		110.7						
Vectren	Benton County (IN)	30.0	30.0			30.0					
NIPSCO	Buffalo Ridge (SD)	50.4									
I&M	Fowler Ridge I (IN)	100.4	100.4				100.4				
I&M	Fowler Ridge II (IN)	50.0	50.0				50.0				
Vectren	Fowler Ridge II (IN)	50.0	50.0			50.0					
IPL	Hoosier (IN)	106.0	106.0					106.0			
IPL	Lakefield (MN)	201.0									
I&M	Headwaters (IN)	200.0	200.0				200.0				
I&M	Wildcat I (IN)	100.0	100.0				100.0				
WVPA/Hoosier	Meadow Lake V (IN)	50.0	50.0							25.0	25.0
		TOTAL: 1,098.5	**797.1**		**110.7**	**80.0**	**450.4**	**106.0**		**25.0**	**25.0**

*IMPA has a 48 MW PPA with Crystal Lake in Iowa that expires Dec. 31, 2018.

Utility PPAs with Indiana Wind Farms: 797.1 MW
Utility PPAs with Out of State Wind Farms: 301.4 MW
Total Utility PPAs: 1,098.5 MW

Cause No. 45564

APPENDIX 7
Solar Photovoltaic Generation Greater than 1 MW (ac)

	Operating Solar Photovoltaic Generators in Indiana 1 MW ac and Larger				
	Location	Utility	County	Installed (MW ac)	Source
1	Crane Solar	Duke	Martin	17.25	Cause Numbers 44932 and 44734
2	Indy Solar No. 1 (Franklin Township)	IPL	Marion	10.00	IPL Feed-in-Tariff Cause No. 44018
3	Indy Solar No. 2 (Franklin Township)	IPL	Marion	10.00	IPL Feed-in-Tariff Cause No. 44018
4	Indianapolis Airport No. 1	IPL	Marion	9.80	IPL Feed-in-Tariff Cause No. 44018
5	Indianapolis Motor Speedway	IPL	Marion	9.00	IPL Feed-in-Tariff Cause No. 44018
6	Indy Solar No. 3 (Decatur Township)	IPL	Marion	8.64	IPL Feed-in-Tariff Cause No. 44018
7	Anderson Solar Park	IMPA	Madison	8.10	IMPA IRP
8	Vertellus	IPL	Marion	8.00	IPL Feed-in-Tariff Cause No. 44018
9	Indianapolis Airport Phase II A	IPL	Marion	7.50	IPL Feed-in-Tariff Cause No. 44018
10	McDonald Solar	Duke	Vigo	5.00	Duke Website and Cause Nos. 44578, 44953
11	Pastime Farm	Duke	Clay	5.00	Duke Website and Cause Nos. 44578, 44953
12	Geres Energy	Duke	Howard	5.00	Duke Website and Cause Nos. 44578, 44953
13	Sullivan Solar	Duke	Sullivan	5.00	Duke Website and Cause Nos. 44578, 44953
14	Anderson I Solar Park	IMPA	Madison	5.00	IMPA IRP
15	Olive	I&M	St. Joseph	5.00	I&M Cause Number 44511
16	Lifeline Data Centers	IPL	Marion	4.00	IPL Feed-in-Tariff Cause No. 44018
17	Washington Solar Park	IMPA	Daviess	3.90	IMPA IRP
18	CWA Authority	IPL	Marion	3.83	IPL Feed-in-Tariff Cause No. 44018
19	Duke Realty #129	IPL	Marion	3.40	IPL Feed-in-Tariff Cause No. 44018
20	Crawfordsville Solar Park	IMPA	Montgomery	3.00	IMPA IRP
21	Peru Solar Park	IMPA	Miami	3.00	IMPA IRP
22	Greenfield Solar Park	IMPA	Hancock	2.80	IMPA IRP
23	Rexnord Industries	IPL	Marion	2.80	IPL Feed-in-Tariff Cause No. 44018
24	Equity Industrial	IPL	Marion	2.73	IPL Feed-in-Tariff Cause No. 44018
25	Duke Realty #98	IPL	Marion	2.72	IPL Feed-in-Tariff Cause No. 44018
26	Duke Realty #87	IPL	Marion	2.72	IPL Feed-in-Tariff Cause No. 44018
27	Twin Branch	I&M	St. Joseph	2.60	I&M Cause Number 44511
28	Deer Creek	I&M	St. Joseph	2.50	I&M Cause Number 44511
29	Indianapolis Airport Phase II B	IPL	Marion	2.50	IPL Feed-in-Tariff Cause No. 44018
30	Huntingburg Solar Park	IMPA	Dubois	2.10	IMPA IRP
31	Lake County Solar, LLC - East Chicago	NIPSCO	Lake	2.00	NIPSCO Feed-in-Tariff Cause No. 43922
32	Lake County Solar, LLC - Griffith	NIPSCO	Lake	2.00	NIPSCO Feed-in-Tariff Cause No. 43922
33	Pendleton Solar Park	IMPA	Madison	2.00	IMPA IRP
34	GSA Bean Finance Center	IPL	Marion	1.80	IPL Feed-in-Tariff Cause No. 44018
35	Citizens Energy (LNG North)	IPL	Marion	1.50	IPL Feed-in-Tariff Cause No. 44018
36	Middlebury Solar, LLC	NIPSCO	Elkhart	1.50	NIPSCO Feed-in-Tariff Cause No. 43922
37	Portage Solar, LLC	NIPSCO	Porter	1.50	NIPSCO Feed-in-Tariff Cause No. 43922
38	Lincoln Solar, LLC	NIPSCO	Cass	1.50	NIPSCO Feed-in-Tariff Cause No. 43922
39	Tell City Solar Park	IMPA	Perry	1.10	IMPA IRP

Cause No. 45564

40	Frankton Solar Park	IMPA	Madison	1.00	IMPA IRP
41	Bartholomew County Solar Farm	Hoosier Energy	Bartholomew	1.00	Hoosier Energy IRP
42	Decatur County Solar Farm	Hoosier Energy	Decatur	1.10	Hoosier Energy IRP
43	Jackson Solar Farm	Hoosier Energy	Jackson	1.10	Hoosier Energy IRP
44	Johnson County Solar	Hoosier Energy	Johnson	1.10	Hoosier Energy IRP
45	Ellettsville Solar Farm	Hoosier Energy	Monroe	1.08	Hoosier Energy IRP
46	Henryville Solar Farm	Hoosier Energy	Clark	1.08	Hoosier Energy IRP
47	Lanesville Solar	Hoosier Energy	Harrison	1.10	Hoosier Energy IRP
48	New Haven Solar	Hoosier Energy	Allen	1.08	Hoosier Energy IRP
49	Scotland Solar	Hoosier Energy	Greene	1.10	Hoosier Energy IRP
50	Spring Mill Solar	Hoosier Energy	Lawrence	1.10	Hoosier Energy IRP
51	New Castle Solar	Hoosier Energy	Henry	1.00	Hoosier Energy IRP
52	Grocers Supply Company	IPL	Marion	1.00	IPL Feed-in-Tariff Cause No. 44018
53	Hobart Solar, LLC	NIPSCO	Lake	1.00	NIPSCO Feed-in-Tariff Cause No. 43922
54	Valparaiso Solar, LLC	NIPSCO	Porter	1.00	NIPSCO Feed-in-Tariff Cause No. 43922
55	Waterloo Solar, LLC	NIPSCO	Dekalb	1.00	NIPSCO Feed-in-Tariff Cause No. 43922
56	Rensselaer Solar Farm	IMPA	Jasper	1.00	IMPA IRP
57	Richmond Solar Farm	IMPA	Wayne	1.00	IMPA IRP

TOTAL: 196.63 MW

Percent of Solar Total 1 MW and Larger		
Utility	**MW**	**Percent**
IPL	91.94	46.8%
IMPA	39.10	19.9%
Duke	37.25	18.9%
Hoosier	11.84	6.0%
NIPSCO	11.50	5.8%
I&M	5.00	2.5%
WVPA	---	0.0%
Vectren	---	0.0%
TOTAL	**196.63**	

Cause No. 45564

APPENDIX 8
Renewable Resource Summary

Indiana Operating Renewable Generation Summary			
	Installed MW	Percent of State Total Installed MW	Percent of State Total Installed MW without Large Wind
Large Wind (above 100kW)	2,114.0	84.8%	
Solar (KW ac)	254.3	10.2%	67.2%
Hydro	58.1	2.3%	15.4%
Landfill Gas	45.6	1.8%	12.1%
Biomass Digesters	14.6	0.6%	3.9%
Small Wind (up to 100 kW)	5.6	0.2%	1.5%
TOTAL	2,492.2	100.0%	100.0%

Cause No. 45564

APPENDIX 9
Renewable Resource Summary with Details

Installed Megawatts of Renewable Energy Generation in Indiana

	Feed-in-Tariffs			Net Metering			Utility Solar		Miscellaneous					
Utility	Wind	Solar	Biomass Digesters	Wind	Biomass	Solar	Utility Owned Solar	Utility Solar PPAs	Small Wind Demos	Large Wind PPAs with Indiana Wind Farms	Merchant Wind (to Indiana or out of state consumers)	Hydro	Landfill Gas	Total
Duke Indiana				2.2		15.7	17.3	19.4		110.7		45.00		210.28
I&M				0.3	0.2	9.9	12.7		0.85	450.4		6.23		480.59
IPL		94.4		0.1		2.3				106.0				202.75
NIPSCO	0.2	18.8	14.3	2.0		8.6						6.82		50.88
Vectren				0.0		7.8				80.0			2.2	90.00
WVPA							0.6			25.0			40.0	65.64
IMPA							36.7							36.70
Hoosier							10.0			25.0			3.4	38.40
Merchant Wind											1,316.9			1,316.9
TOTAL	**0.2**	**113.2**	**14.3**	**4.6**	**0.2**	**44.3**	**77.3**	**19.4**	**0.9**	**797.1**	**1,316.9**	**58.1**	**45.6**	**2,492.1**

Wind										**797.1**	**1,316.9**			2,114.0
Solar		**113.2**				**44.3**	**77.3**	**19.4**						254.3
Hydro												**58.1**		58.1
Landfill Gas													**45.6**	45.6
Biomass Digesters			**14.3**		**0.2**									14.6
Small Wind	0.2			**4.6**					**0.9**					5.6
														2,492.1

	MW	**Percent**
Wind	2,114.0	84.8%
Solar	254.3	10.2%
Hydro	58.1	2.3%
Landfill Gas	45.6	1.8%
Biomass Digesters	14.6	0.6%
Small Wind	5.6	0.2%
Total	2,492.1	100.0%

Cause No. 45564

APPENDIX 10
Generation by Fuel Type for Indiana Consumption

Generation Percentage for Indiana Consumption by Fuel Type

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Coal	85.5%	86.7%	88.5%	82.6%	77.7%	72.9%	76.3%	76.6%	67.9%	64.6%	64.5%
Nuclear	9.0%	8.0%	4.6%	7.9%	8.9%	9.6%	9.1%	9.4%	9.8%	9.8%	10.6%
Natural Gas, Other Gases	4.6%	4.3%	4.6%	6.3%	9.1%	13.4%	9.4%	9.2%	16.0%	19.3%	19.2%
Wind	0.0%	0.2%	1.1%	2.2%	2.5%	2.5%	2.9%	2.7%	3.9%	3.9%	4.2%
Oil	0.1%	0.1%	0.1%	0.1%	1.0%	0.7%	1.3%	1.1%	1.2%	1.2%	0.1%
Hydro	0.3%	0.3%	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%	0.2%	0.3%
Biomass	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%
Other	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	0.3%	0.4%	0.4%	0.3%
TOTAL	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

	2008	2017	Change
Coal	86.7%	64.5%	-22.3%
Nuclear	8.0%	10.6%	2.7%
Natural Gas, Other Gases	4.3%	19.2%	14.9%
Wind	0.2%	4.2%	4.0%
Oil	0.1%	0.1%	0.0%
Hydro	0.3%	0.4%	0.1%
Solar	0.0%	0.3%	0.3%
Biomass	0.2%	0.4%	0.2%
Other	0.3%	0.3%	0.0%
TOTAL	100.0%	100.0%	100.0%

Notes:

1. This data is based on EIA electric generation data for 2017 (preliminary) for Indiana.

2. The production from the Cook Plant is based on IM Power FERC Form 1 Data for 2017 and Form PR for 2016.

3. The IM Power Form PR for 2017 is not available as of 5-23-18.

4. This analysis assumes energy transfers in/out of Indiana will not change these percentages significantly.

Cause No. 45564

APPENDIX 11
Map of Generating Units

DUKE ENERGY INDIANA
1. Gibson.................... 3,132
2. Wabash River......... Retired
3. Cayuga.................. 1,094
4. Edwardsport.............. 595
5. Gallagher.................. 280
6. Noblesville................. 285
7. Connersville.................86
8. Henry County.............. 129
9. Madison (OH) 576
10. Miami Wabash 80
11. Vermillion 1-5............. 355
12. Wheatland 460
38. Markland 45

HOOSIER ENERGY
13. Merom...................... 982
14. Holland (IL)................. 312
15. Ratts .... Retired
16. Lawrence................... 176
17. Worthington............... 175

INDIANA MUNICIPAL POWER AGENCY
18. Georgetown 2&3......... 146
19. Trimble County (KY) 162
20. Anderson 139
21. Richmond 68
22. Whitewater Valley.... Inactive
39. Prairie State............... 200
O. Other Cities

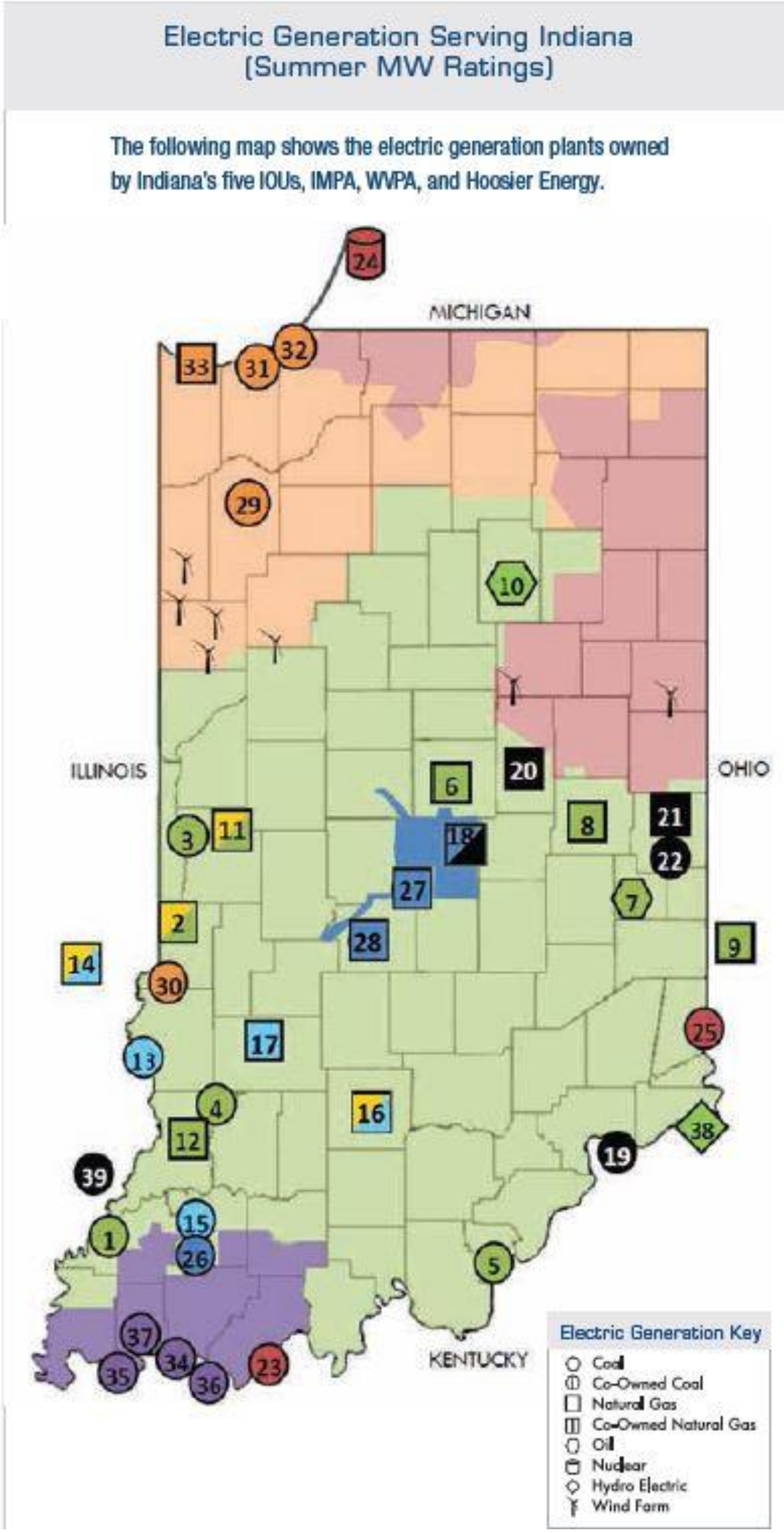
INDIANA MICHIGAN POWER
23. Rockport 2,600
24. Cook (MI)................ 2,160
25. Tanners Creek .... Retired

INDIANAPOLIS POWER & LIGHT
18. Georgetown 1&4 150
26. Petersburg.............. 1,715
27. Harding Street 628
28. Eagle Valley 671

NORTHERN INDIANA PUBLIC SERVICE COMPANY
29. Schahfer 1,780
30. Sugar Creek............... 535
31. Bailly.......................... 31
32. Michigan City.............. 469
33. Mitchell .... Retired

VECTREN SOUTH
34. Warrick..................... 150
35. Brown 640
36. Culley 360
37. Broadway/Northeast..... 85

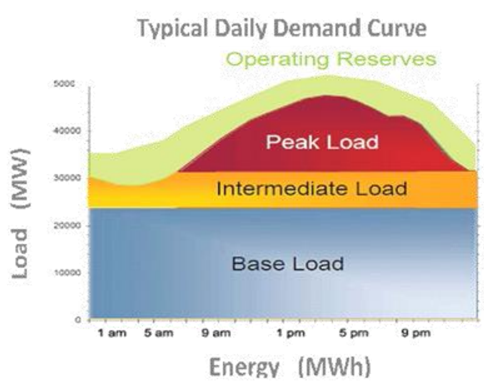
WABASH VALLEY POWER
2. Wabash River Highland . 162
11. Vermilion 6-8 240
14. Holland (IL)................. 314
16. Lawrence...................... 86

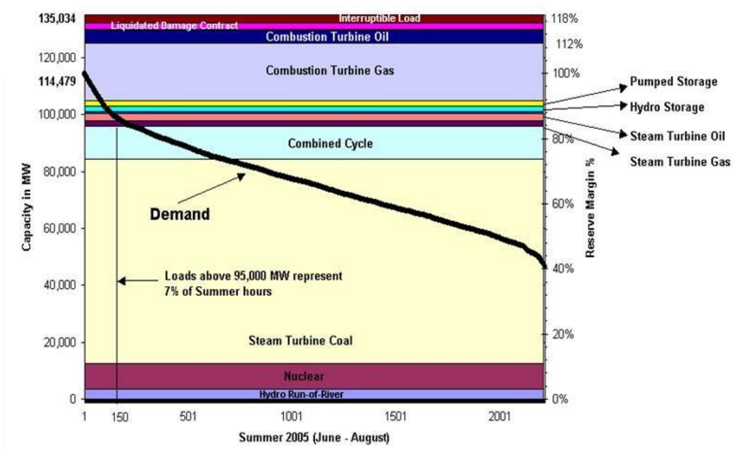


Cause No. 45564

APPENDIX 12
DEFINITION OF TERMS and ACRONYMS

Base Load Generation: Traditoinally regarded as generating equipment that is normally operated to meet demand on continous bases (e.g., over a 24-hour basis). The North American Electric Reliability Corporation (NERC) characterization of Base Load: *There is a distinction between baseload generation and the characteristics of generation providing reliable "baseload" power. Baseload is a term used to describe generation that falls at the bottom of the economic dispatch stack, meaning [those power plants] are the most economical to run. Coal and nuclear resources, by design, are designed for low cost O&M [operation and maintenance] and continuous operation […] However, it is not the economics nor the fuel type that make these resources attractive from a reliability perspective. Rather, these conventional steam-driven generation resources have low forced and maintenance outage hours traditionally and have low exposure to fuel supply chain issues. Therefore, "baseload" generation is not a requirement; however, having a portion of a resource fleet with high reliability characteristics, such as low forced and maintenance outage rates and low exposure to fuel supply chain issues, is one of the most fundamental necessities of a reliable BPS. These characteristics ensure that "baseload" generation is more resilient to disruptions.* Staff Report to the Secretary on Electricity Markets and Reliability, Page 5, August 2017. It has been suggested that the term "baseload" generation is no longer a meaningful distinction since natural gas combined cycle facilities (NGCC), in particular, are increasingly displacing traditional large coal and nuclear generating units in economic dispatch.





Battery Storage: Has been used as a generating resource, to support transmission, and to enhance reliability of the distribution system. That is, battery storage transcends the three segments. Batteries can facilitate integration of Distributed Energy Resources (DERs) –including solar and other renewable resources, microgrids, DSM, and future technologies.

Coincident Demand (CD): Mathematically, it is the sum of two or more demands that occur in the same time interval. Typically, used in planning resources such as generation, transmission, and demand response. So, the contribution by any entity to the RTOs / ISOs peak is that entity's "**Coincidence Factor (CF)**." In regions not served by an RTOs / ISOs, the relevant peak is the contribution of each customer to their utility's peak demand.

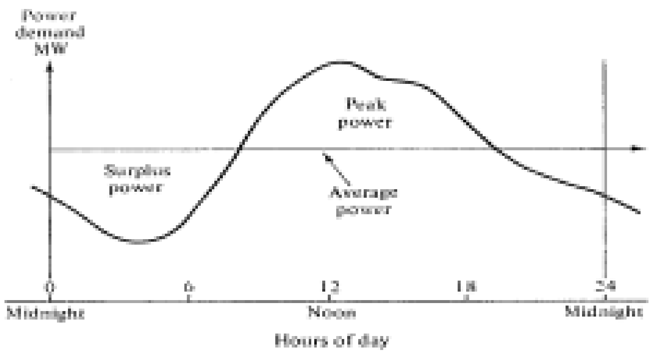
Coincident Peak Demand (CP): For example, in regions served by RTOs / ISOs, the relevant peak is the RTOs / ISOs peak demand rather than the peak demand of any utility or other entity. In regions not served by RTOs / ISOs, the relevant peak is the contribution of each customer to their utility's peak demand. For retail ratemaking CP typically refers to the utility's peak demand since the timing of the RTO / ISO peak is difficult to predict, most Indiana utilities experience a peak that is close to the MISO's and PJM's peak. Therefore, Indiana utilities have a high coincidence factor with MISO and PJM.

Combined Heat & Power (CHP): A plant designed to produce both heat and electricity from a single heat source. *Note: This term is being used in place of the term "cogenerator" that was used by EIA in the past.* CHP better describes the facilities because some of the plants included do not produce heat and power in a sequential fashion and, as a result, do not meet the legal definition of cogeneration specified in the Public Utility Regulatory Policies Act (PURPA).

Cause No. 45564

Congestion of the Transmission or Distribution Systems; Congestion: A condition that restricts the ability to add or substitute one source of electric power for another on a transmission grid or distribution system (more simply: congestion occurs when insufficient transfer capacity is available to implement all of the preferred schedules simultaneously). In regions served by RTO/ISO, this congestion is "cleared" by the use of economic price signals referred to as **Locational Marginal Cost Pricing (LMP**). Prior to RTO / ISOs and in areas not served by RTO / ISOs, transmission congestion is cleared by the use of "**Transmission Line Loading Relief" (**TLRs). TLRs, in extreme instances, curtail even firm transactions to prevent a blackout condition. Natural gas pipelines may also experience congestion.

Distributed Energy Resource (DER): DER is a resource sited close to customers that can provide all or some of their electric and power needs and can also be used by the system to either reduce customer demand or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, relatively small scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE).Note the IEEE Standard 1547 does not include Demand Response (DR) but this is a matter for policymakers. DER can provide back-up power, used to displace relatively high cost energy such as at the time of system peak demand, can stabilize the grid, firm up other resources, potentially reduce back-feed problems, and enhance power quality. Source: Grid Modernization Laboratory Consortium, U.S. Department of Energy.

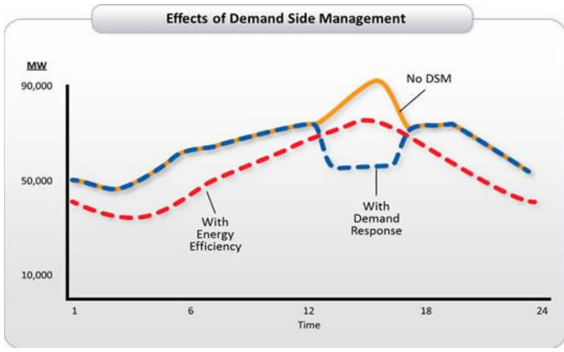


Some of the potential advantages of DER include: 1) reduced demand on system elements and peak demand which may result in a deferral of transmission and distribution upgrades, 2) increase the diversity of the resource mix, 3) provides voltage and frequency support, 4) reduce line losses, 5) provides back-up power in emergencies and may provide spinning reserves and black start capabilities to help restore the system, 6) reduced emissions in heavily populated areas, 2) increase the diversity of the resource mix, 3) provides voltage and frequency support, 4) reduce line losses, 5) provides back-up power in emergencies and may provide spinning reserves and black start capabilities to help restore the system, 6) reduced emissions in heavily populated areas

Diversity Factor: The electric utility system's load is made up of many individual loads that make demands upon the system usually at different times of the day. The individual loads within the customer classes follow similar usage patterns, but these classes of service place different demands upon the facilities and the system grid. The service requirements of one electrical system can differ from another by time-of-day usage, facility usage, and/or demands placed upon the system grid.

Demand Side Management (DSM): The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers to only energy and load-shape modifying activities that are undertaken in response to utility-administered programs. It does not refer to energy and load-shaped changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards. Demand-Side Management covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

Cause No. 45564



Fracking: The fracturing of rock by a pressurized liquid is **Hydraulic fracturing.** This is a technique in which water is mixed with sand and chemicals, and the mixture is injected at high pressure into a wellbore to create small fractures to extract oil and natural gas. Oil and Natural Gas *Plays* have been discovered in almost every state.

Integrated Resource Planning (IRP): The engagement in a systematic, comprehensive, and open utility / stakeholder analysis of loads and resources to enable planners and stakeholders to achieve greater optimality in the planning of a robust portfolio of resources including transmission, all forms of generation, demand-side management (including energy efficiency) and distribution planning with the aspiration of providing the lowest delivered cost of electricity.

Intermittent Resources: Sometimes referred to as Variable Resources. These are sources of power, such as wind and solar, that cannot operate continuously. These often require "back-up" or supplemental power sources to firm the supply of power.

Levelized Cost of Electricity (LCOE): The National Renewable Energy Laboratory defines LCOE as: The LCOE is the total cost of installing and operating a project expressed in dollars per kilowatt-hour of electricity generated by the system over its life. It accounts for: Installation costs; financing costs; taxes; operation and maintenance costs; salvage value; incentives; revenue requirements (for utility financing options only); and the quantity of electricity the system generates over its life. To use the LCOE for evaluating project options, it must be comparable to cost per energy values for alternative options.

Load Diversity: The difference between the peak of coincident and non-coincident demands of two or more individual loads. From a system planning perspective, diversity is the difference between the individual peak demand of a customer or customer class to the system peak demand of a utility.

Load Forecasting: This is the analytical process of estimating customer demand for electricity over a specified period of time (e.g., 1 day – 30 years) and as a basis for determining the resource requirements to satisfy customer requirements in a reliable and economic manner. Typically a utility will want to forecast maximum demand in the amount of Watts usually Megawatts (MW) or Gigawatts (GW) and energy use in Megawatt hours (MWh) or Gigawatt (GWh) hours. Forecasts that are well developed provide a higher degree of believability (confidence) and can, therefore, reduce the financial risks associated with planning resources over the forecast horizon.

Locational Marginal Cost Pricing (LMP): Determining the cost of power at any one point on the grid (including the opportunity costs created by congestion) is called *location-based marginal costing*. A Locational Marginal Price (LMP) is the market clearing price at a specific Commercial Pricing Node (CPNode) and is equal to the cost of supplying the next increment of load at that location. LMP values have three components for Settlement purposes: marginal energy component, marginal congestion component, and marginal loss component. The value of an LMP is the same whether a purchase or sale is made at that node and is equal to the cost of supplying the next increment of load at that location. LMP values have three components for Settlement purposes: marginal energy component, marginal congestion component, and marginal loss component. The value of an LMP is the same whether a purchase or sale is made at that node.

LOLE (also LOLP determination of Resource Adequacy): Used to set "Planning Reserve Margins." LOLE is normally expressed as the number of days/year that generation resources will be insufficient to meet load. Most widely accepted level: 1 Day (or event) in 10 Years. This, like the "Loss of the Single Largest Generator" or a fixed percentage above forecasted peak demand (e.g., 15%) are all arbitrary measures for attempting to quantify the amount of capacity in excess of peak demand required to reliably serve customers.

Cause No. 45564

Planning Horizon: For purposes of the IRP, utilities' resource plans encompass 20 years. The 20 years is intended to avoid an unintentional bias of selecting lower cost resources when a more costly (capital intensive) resource might be preferable in the longer term due to offsetting costs such as lower fuel cost. Typically, utilities extend their planning horizon beyond 20 years to avoid the *event horizon effect* where resources that might be economically desirable for inclusion in the plan are omitted because their viability occurred just beyond the 20 years).

Planning Reserve Margin (PRM): The amount of forecast dependable resource (i.e., generation, demand-response) capacity required to meet the forecast demand for electricity and reasonable contingencies (e.g., loss of a major generating unit). "Dependable" should be used in preference to "Nameplate" because the Nameplate Rating of a resource may not be able to provide dependable capacity at the time of peak. Often established to meet a "Loss of Load Probability" (or Expectation) of one event (or day) in ten years. Typically this construct has resulted in Planning Reserve Margins of around 15% (i.e., 15% greater than the forecast peak demand). While a specified LOLP is arbitrary, it is generally regarded as a reasonable criteria.

Reserve Margin (RM): The percentage difference between rated capacity and peak load divided by peak load. Reserve Margin = [(Capacity-Demand)/Demand]. A 15 percent reserve margin is equivalent to a 13 percent capacity margin. Capacity Margin = [(Capacity-Demand)/Capacity].

$$\text{Reserve Margin} = \frac{Resources - Peak\ Firm\ Demand}{Peak\ Firm\ Demand}$$

Resource Adequacy (RA): Planning Coordinators such as RTOs / ISOs establish Resource Adequacy requirements (and the resulting long-term_planning reserve margins for their member utilities) to ensure that sufficient resources such as electric generation, transmission, demand response, and customer-owned generation are available to allow Planning Coordinators to reliably meet its forecast requirements. For utilities in RTOs / ISOs, the allocated Reserve Margin and the estimated future prices of capacity, in turn, may be used by individual utilities in the development of their long-term Resource Plans.

Resource Diversity: In an electric system, resource diversity may be characterized as utilizing multiple resource types to meet demand. A more diversified system is intuitively expected to have increased flexibility and adaptability to: 1) mitigate risk associated with equipment design issues or common modes of failure in similar resource types, 2) address fuel price volatility, and 3) reliably mitigate instabilities caused by weather and other unforeseen system shocks. In this way, resource diversity can be considered a system-wide tool to ensure a stable and reliable supply of electricity. Resource diversity itself, however, is not a measure of reliability. Relying too heavily on any one fuel type may create a fuel security or *resilience* issue because the level of resource mix diversity does not correlate directly with a resource portfolio's ability to provide sufficient generator reliability attributes. However, fuel and resource diversity are closely related. Resource diversity entails with more detailed information about the operational characteristics of each resource. Resource diversity is also related to load diversity. The value of resource diversity can change dramatically due to changes in the capital cost of different resources, the profitability of different resources in the dispatch, the of capital costs associated with alternative resources, and the dynamics of the pricing and projected prices of different fuels.

Security Constrained Economic Dispatch (SCED): When congestion occurs, least-cost generation often must be passed over for purposes of system security. For this reason, this market model – where the system operator acts as a clearing agent *and* manager of system security – is called *bid-based, security-constrained economic dispatch.*

Cause No. 45564

ACRONYMS

AC	Alternating Current
ASM	Ancillary Services Market
CO_2	Carbon Dioxide
CCR	Coal Combustion Residuals Rule
CPCN	Certificate of Public Convenience and Necessity
CAA	Clean Air Act (CAA)
CAAA	Clean Air Act Amendments
CPP	Clean Power Plan Power Plan
CF	Coincidence Factor
CP	Coincident Peak Demand (see also non-coincident peak demand)
CHP	Combined Heat & Power
CC	Combined Cycle generator
CS	Community Solar
CPV	Concentrating Photovoltaic
CSP	Concentrating Solar Power
kW, MW, GW	kilowatts, megawatts, and gigawatts
DR	Demand Response
DSM	Demand-Side Management
DER	Distributed Energy Resources
ED	Economic Dispatch
ELG	Effluent Limitation Guidelines
kWh, MWh, GWh	kilowatt hours, megawatt hours, gigawatt
EE	Energy Efficiency
EPA	Environmental Protection Agency Protection Agency
EUR	Estimated Ultimate Recovery of natural gas or oil
FERC	Federal Energy Regulatory Commission
FGD	Flue-Gas Desulfurization
ITC	Investment Tax Credit
LRZ	Local Resource Zones (part of MISO's reliability construct)
LMP	Locational Marginal Cost Pricing
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MPS	Market Potential Studies
MATS	Mercury and Toxic Standard
MTEP	MISO's Transmission Expansion Plan
MVP	MISO's Multi-Value Transmission Projects
NOx	Nitrogen Oxide
NERC	North American Electric Reliability Corporation
O&M	Operations & Maintenance Costs
PRM	Planning Reserve Margin
PPA	Power Purchase Agreements
PVRR	Present Value of Revenue Requirements
PTC	Production Tax Credit
RTP	Real Time Pricing
RTOs	Regional Transmission Organizations (also Independent System Operators)
RPS	Renewable Portfolio Standards
RM	Reserve Margin
RA	Resource Adequacy
RTEP	Regional Transmission Expansion Plan (PJM)
SCED	Security Constrained Economic Dispatch
SOx, SO_2, SO_3	Sulfur Oxides