Plum Point Energy Station
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April 24, 2020

Division of Environmental Quality
Office of Air Quality- Policy and Planning Branch
5301 Northshore Drive
North Little Rock, AR 72118

Re: Information Request Regarding Candidate Technologies

Dear Sir or Madam,

Please see the attached response to ADEQ's request regarding candidate technologies. The attachment includes a response to each applicable request and a Heat Rate Improvement study that will provide information for Plum Point Energy Station's Existing Characteristics and supporting data for each response.

If you have any questions, please contact Matt Gray at 870-563-5072.

Thank you,

Matt Gray

Matt Gray
Environmental Specialist

PLUM POINT ENERGY STATION ARKANSAS DIVISION OF ENVIRONMENTAL INFORMATION REQUEST

B&V PROJECT NO. 404370
B&V FILE NO. 14.4100

PREPARED FOR

Plum Point Services

17 APRIL 2020

BLACK & VEATCH

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1.0 Summary

The following text are suggested responses for use by Plum Point Services to the Arkansas Department of Energy and Environment, Division of Environmental Quality (DEQ) letter dated November 5, 2019. The responses in this report have all been provided by Black & Veatch Corporation (henceforth "Black & Veatch") as a result of the EPA-ACE heat rate improvement study which was conducted on behalf of Plum Point Services in 2020, as well as additional opinion and analysis provided by our subject matter experts.

2.0 Technology and Practices

1) Neural Network/Intelligent Sootblower System Information:
   a) Please indicate whether each unit listed above is tied in to a neural network system to optimize the unit's operations and minimize emissions.
      - ***The unit is not tied in to a neural network system, and this has been the case since unit installation.***

      i. If a unit is tied in to a neural network system,
         1. When was the neural network first operated?
         2. What impact did this have on your heat rate?

      ii. If a unit is not tied in to a neural network system and the technology is feasible:
         1. Please quantify the cost to implement a neural network system for your unit.

      - ***As a result of engagement by Black & Veatch, the estimated overall cost is $450,000 for implementation. This cost was estimated based upon actual installed costs of recent neural network projects, also based upon the practical experience of past Black & Veatch project work with a commercial neural network vendor (Neuco) and escalating to current prices.***

         2. Please quantify the expected heat-rate impact of implementation of a neural network system.

      - ***Black & Veatch has estimated a potential heat-rate improvement of 0.17% to 0.23%.***

      iii. If the technology is not technically feasible or is limited, then please provide a detailed explanation of why the technology is not technically feasible or is limited due to the unique characteristics of each unit.

   b) Is an intelligent soot blower system operated for any of the units listed above?
      - ***The unit does not have an intelligent soot blower system, and this has been the case since unit installation.***

      i. If an intelligent soot blower system is operated for the unit, then please respond to the following questions:
         1. Is the intelligent soot blower system incorporated into the neural network software? If so, does the impact you specified for l)a)i)2 include the impact of the intelligent soot blower system?
         2. If the intelligent soot blower system is not incorporated into a neural network software package, the please respond to the following:
            a. When was the intelligent soot blower system first operated?
            b. What impact did this have on your heat rate?

ii. If an intelligent soot blower system is not operated for the unit and is technically feasible, then please respond to the following:

1. Please quantify the cost to install an intelligent soot blower for your unit.

- ***Black & Veatch has determined an overall estimated cost of $350,000. This cost was estimated based upon recent projects implemented by coal-fired EGUs of similar size and complexity to Plum Point.***

2. Please quantify the expected heat rate impact of the intelligent soot blower system.

- ***Black & Veatch has estimated a potential heat-rate improvement of 0.02% to 0.04%.***

iii. If the technology is not technically feasible or is limited, then please provide a detailed explanation of why the technology is not technically feasible or is limited due to the unique characteristics of each unit.

c) Please provide any other information relevant to DEQ's analysis of this candidate technology.

2) Boiler Feed Pumps:

a) Over the past year, how does the performance of the boiler feed pumps for each unit compare to the manufacturer specifications?

- ***The A boiler feed pump (BFP) train (main BFP and booster BFP) is producing 3.5% less total dynamic head (TDH) than design, but the B boiler feed pump train is producing 0.5% more TDH than design. A formal test was not performed; values are based on operational data using plant instrumentation and are subject to instrument error. Thus, according to Black & Veatch, the BFP performance has not degraded significantly from that of a new unit which has undergone typical scheduled maintenance since installation.***

b) When was the last time the boiler feed pump(s) for each unit was overhauled or upgraded?

- ***The "Bravo" BFP was overhauled in October, 2015***
- ***The "Alpha" BFP was overhauled in April, 2017***

c) If the boiler feed pumps have not been overhauled or upgraded in the period or at the performance characteristics recommended by the manufacturer specifications,

i. Please quantify the cost to overhaul or upgrade the boiler feed pump(s) for your unit.

ii. Please quantify the expected heat rate impact of overhauling or upgrading the boiler feed pump(s).

iii. Please provide any other information relevant to the DEQ's analysis of this candidate technology.

d) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

- ***Please see item (a) above – due to the young age of the unit and the current performance of the boiler feed pumps, there is no improvement to internals that would result in a statistically significant improvement to efficiency.***

3) Please specify whether the air pre-heater for each unit listed above is regenerative (rotary) or recuperative (tubular or plate).

- ***Tri-sector regenerative air pre-heaters.***

a) If your unit has a regenerative air pre-heater, when were the seals last replaced?

- ***The seals have not been replaced since the unit came on-line. Additionally, the leakage rates for the air heaters do not warrant seal replacement based on the latest leakage tests done by Storm Technologies Inc in January of 2019.***

b) If the seals have not been replaced in the period or at the performance characteristics recommended by the manufacturer specifications,

i. Please quantify the cost to replace the seals for the regenerative air pre-eater for your unit.

- ***A budgetary estimate to replace the air pre-heater seals would be about $1.5 million.***

ii. Please quantify the expected heat-rate impact of from replacing the seals.

- ***Currently, there is no benefit to replacing the air heater seals, because the leakage rates from 2019 tests are comparable to those seen with new seals. In the future, the heat-rate impact from new seals would be dependent on the deteriorated state of replaced seals.***

c) Please provide any other information relevant to DEQ's analysis of this candidate technology.

- ***The air pre-heaters were installed with seals that are of the latest technology, and no benefit to the heat rate should be expected by replacing the seals. Periodic testing should be conducted to track the air pre-heaters' performance, and if leakage rates significantly increase in the future, discussions should occur about when to replace the air heater seals and/or baskets. The benefit to heat rate will depend on the reduction of air pre-heater leakage. Generally, this should be expected to be less than 1 percent.***

d) Please provide a detailed explanation if the technology or practice is not technically feasible or limited due to the unique characteristics of the unit.

- ***There should be no technical reason that prohibits replacing the seals in the future. However, at this time there is no technical reason to do so, because the air pre-heaters are operating with low leakage rates.***

4) Variable Frequency Drives (VFD) information for each listed unit:
   a) Does your unit have VFD controls for the induced draft (ID) fans?
      - ***No, Plum Point does not have VFDs installed on any of the ID fan motors.***

      i. If so,
         1. When was the VFD first operated?
         2. What impact did this have on your heat rate during base-load and cycling operating scenarios?

      ii. If not,
         1. Please quantify the cost to install and operate a VFD for the ID fans for your unit.

      - ***Black & Veatch estimated an installed capital cost of $4.61 million and an annual O&M cost of $6,000 ($3,000 per fan). The capital costs were developed based upon averages from vendor quotes on similar VFD installation projects within the last 4-6 years. These estimates that have been employed in EPA-ACE studies have been validated independently in 3 other EPA-ACE projects where independent vendor quotes were sought in parallel. The O&M cost estimate is based upon vendor quotes as well, and represents the differential cost which is largely associated with the electronic controls and cooling systems for the VFDs.***

         3. Please quantify the expected heat-rate impact of the installation and operation of VFD for ID fans for both base-load and cycling operating scenarios.

      - ***Black & Veatch estimated a heat rate improvement of 0.32% at full load and 0.8% at low load.***

   b) Does your unit have VFD controls for the boiler feed pumps?
      - ***No, Plum Point does not have VFDs installed on any of the boiler feed pump (BFP) motors.***

      i. If so,
         1. When was the VFD first operated?
         2. What impact did this have on your heat rate during base-load and cycling operating scenarios?

      ii. If not,
         1. Please quantify the cost to install and operate a VFD for the boiler feed pump(s) for your unit.

      - ***The installed capital cost adding VFDs to the BFPs has been estimated as $2.2 million with an annual O&M cost of $6,000 ($3,000 per pump). This was based upon Black & Veatch project experience with similar retrofit projects, where the cost for VFD deployment has been estimated generally between $600,000 to $1,300,000 per BFP as an all-in cost.***

2. Please quantify the expected heat rate impact of the installation and operation of VFD for the boiler feed pump(s) for both base-load and cycling operating scenarios.

- ***Black & Veatch estimated an increase in heat rate of 0.06% at full load and a heat rate improvement of 0.53% at low load.***

iii. Please provide any other information relevant to DEQ's analysis of this candidate technology.

- ***The potential benefit of adding VFDs to the large draft fans and the circulating water and boiler feed pumps was explored by Black & Veatch. Black & Veatch analyzed the impact of VFD addition using operating conditions and performance curves of the equipment.***

c) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.

5) Blade Path Upgrade (Steam Turbine) for each listed unit:
Has the steam turbine for the unit been upgraded or overhauled in the past ten years?

- ***There have been no steam turbine technology upgrades in the past 10 years. The steam turbine was relatively new and was commissioned in 2010. The most recent turbine overhaul was completed in May 2017 during the spring outage.***

a) If so,

i. When was the turbine upgraded or overhauled?

- ***May, 2017***.

ii. Describe how the turbine was upgraded or overhauled.

- ***The original base work scope was an HIP major inspection, main turbine valve inspection, minor generator inspection, installation of 8th and 9th stage diaphragm stiffeners, and replacement of the 10th stage diaphragm. During the outage additional items were discovered to be in need of repair. The turbine underwent disassembly, inspection, repair, and reassembly of the HIP, LPA, LPB, lube oil system, seal oil system, EHC oil system, and main steam turbine valves. The generator was inspected. A tops-off laser alignment was performed on the steam path centerline and bearings by Total Laser Alignment (TLA). TLA also performed long line analysis.***

iii. How did the upgrade or overhaul impact the unit's heat rate?

- ***The plant reported experienced an increase in net generation capability without significantly impacting the heat rate other than returning it to normal expected conditions.***

iv. Are there further upgrades available that would improve the efficiency of the turbine?
   - ***The cost to upgrade the HP/IP steam path of the steam turbine is estimated to be about $18.9 million. The cost for a full steam path upgrade of the steam turbine is estimated to be about $31.3 million. The potential heat rate improvement due to HP/IP steam path upgrade and full steam path (HP/IP/LP) upgrade of the steam turbine is estimated to be about 0.3% and 0.9% respectively. This was based upon recent steam turbine upgrade projects studied and conducted by Black & Veatch, as well as the result of detailed computer modeling.***

b) If not,
   i. Please quantify the cost to upgrade or overhaul the steam turbine for your unit. (You may factor the costs associated with new source review, if it would be triggered by the upgrade, into your cost calculations)
   ii. Please quantify the expected heat rate impact of upgrading or overhauling the steam turbine.

c) Please provide any other information relevant to DEQ's analysis of this candidate technology.
   - ***The potential benefit of upgrading the steam turbine was explored by engaging Black & Veatch. Black & Veatch modeled the Plum Point Unit steam turbine using industry-leading Thermoflow software and by considering the design conditions and the potential improvement in turbine section efficiencies for upgrades based on review of past in-house turbine upgrade studies and proposals.***

d) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.
   - ***The findings of the Black & Veatch study were that the potential improvement in turbine section efficiencies and plant heat rate with a steam path upgrades in the near future is estimated to be not significant due to relatively low age of the steam turbine. The cost of implantation of steam turbine upgrade is relatively high with low potential improvement in heat rate.***

6) Economizer for each listed unit
   a) When was the economizer last replaced?
      - ***The economizer has never been replaced or modified due to the relative new condition of the unit (entered service September, 2010).***
   b) Throughout the past year, how does the performance of the economizer for each unit compare to the manufacturer specifications for a new unit?
      - ***The economizer performance has not degraded significantly from that of a new unit which has undergone typical scheduled maintenance since installation.***
   c) If the performance of the economizer for a unit has degraded outside the performance range of the manufacturer's specifications:
      - ***Not applicable, as the unit has NOT experienced a statistically significant degradation in heat rate performance regarding the economizer since it was installed.***

      i. Please quantify the cost to redesign/replace the economizer for your unit.

      ii. Please quantify the expected heat-rate impact of redesigning/replacing the economizer.
   d) Please provide any other information relevant to DEQ's analysis of this candidate technology.
      - ***The potential benefit of adding tube surface area to this unit was explored by engaging Black & Veatch. Black & Veatch performed computer modeling of the heat transfer and other impacts resulting from changes to the economizer surface area, utilizing the Electric Power Research Institute Vista modeling software. This method of analysis has been successfully employed in economizer modification studies for more than 50 other unit-level EPA-ACE studies, as well as retrofit and design-basis validation projects around the world for more than 20 years.***
   e) Please provide a detailed explanation if the technology is not technically feasible or limited due to the unique characteristics of the unit.
      - ***The findings of the Black & Veatch study were that adding tube surface area to the economizer would result on only a very small improvement in the boiler efficiency and overall plant heat rate, at a high cost. Assuming a future net capacity factor of 65.8%, on an annual average basis the best heat rate improvement potential was only 0.16% at a cost of $2.2 million or greater. This represents a relatively high cost of $13.75 million per 1% heat rate improvement. Moreover, potential modifications to sootblowing systems would be required, which were not priced as part of this study, but which would increase the cost of implementation***.

7) Heat Rate Improvement Practices:
   a) Do the staff at the plant where the unit is located undergo routine training that would positively affect the heat rate of the unit or units? (Such training may include any training related to efficiency or any other training on practices that result in heat rate improvements.)
      - ***Training currently is informal and targeted to specific projects or station needs, thus is not regular or routine.***

      i. If so, describe the training program including frequency of training and practices taught.
      ii. If not,
         1. Please provide to DEQ a plan for instituting such a program.
      - ***Various options are available for formal training programs. Employing a third-party engineering training firm to conduct general heat rate awareness training is available, as is site-specific training that could be developed and conducted by a third party. Alternately, the plant could develop an internal training regimen either independently or cooperatively with a third party.***

         2. Quantify the annual costs of implementing a program.
      - ***The cost for an individual general heat rate awareness training course to train from 10-20 staff is expected to cost about $15,000. Developing and conducting a detailed site-specific course could be as much as $25,000 to $40,000 for the initial execution, with regular updates to the course and training costs being from $10,000 to $15,000 per year.***

         3. Quantify the expected heat-rate impacts of implementing a program.
      - ***In practice this is impossible to conclusively quantify, as any benefits depend not only upon implementation by the attendees, but their ability to foment change in heat rate at the plant, as well as having opportunity to do such due to the plant condition and situation. However, it has been the experience of Black & Veatch, based upon anecdotal reports subsequent to conducting heat rate awareness training at a large number of plant sites, that typically some targeted improvement is discovered which has the potential to improve heat rate by 0.1 to 0.5%.***

   b) EPA requires DEQ to consider an "on-site appraisal" of heat-rate improvement opportunities at a specific unit. Please submit a report detailing the results of an on- site appraisal of heat-rate improvement opportunities. This appraisal may be conducted by an internal group or a third-party. Include a summary of the most recent inspection and recommendations for equipment maintenance or replacement to minimize heat-rate deviations, and include actions taken in response to the recommendations.
      - ***Plum Point currently monitors plant heat rate on a daily basis, as well as performing heat rate calculations and corrections during their capacity testing. Plum Point is currently proactively implementing a Black & Veatch ASSET360 online***

monitoring and diagnostics system, which has in its long history and widespread use in the industry been successful at helping plants to uncover many opportunities for heat rate improvement, as well as preventing unplanned outages and reducing the length of scheduled outages which also brings an annual benefit to heat rate. Furthermore, Plum Point has in 2020 become a member of the Electric Power Research Institute (EPRI) Vista fuel quality impact program Users Group, which was done as part of the efforts to address EPA-ACE. This EPRI program has a very long validated history of use with heat rate improvement studies and assessments, both from fuel quality optimization and equipment performance study capabilities.

c) Does your plant have a routine steam surface condenser cleaning program?

- ***Yes. For both the HP and LP condensers, the unit performs manual removal of debris during outages. Additionally, a biodetergent (ChemTreat product CL-456) is used at the cooling tower. A shock feed is done three days per week, which translates to a total of approximately 60 gallons.***

i. If so, describe the impact that this program has on the heat rate of each unit.

- ***The plant chemist has stated that this biodetergent (1) minimizes the potential for cooling tower fouling (2) minimizes the potential for biofilm development, and (3) keeps the heat exchange surfaces cleaner, allowing for better heat transfer. Black & Veatch was engaged in reviewing HP and LP condenser performance before and after four major outages (fall 2017, spring 2018, fall 2018, and spring 2019) and found negligible change in performance across time, which is the desired effect of the cleaning program.***

ii. If not,

1. Please provide to DEQ a plan for instituting such a program.
2. Quantify the annual costs of implementing a program.
3. Quantify the expected heat-rate impacts of implementing a program.

d) Please provide a detailed explanation if a practice is not technically feasible or limited due to the unique characteristics of the unit.

- ***N/A***

e) Please provide any other information relevant to the State's analysis of these practices.

8) Gross vs net generation standards:

a) Would you recommend the standards of performance for each affected unit be established in pounds of carbon dioxide emitted per net megawatt hour or per gross megawatt hour? Explain your recommendation.

- ***The potential benefits of gross versus net analyses have been studied at more than 50 units across the United States by Black & Veatch, and innumerable advisory conversations have been conducted with other utility environmental and engineering personnel at the unit and corporate level. Black & Veatch feels very***

much that the best option is to establish a CO_2 performance standard on a net MWh basis. This is due to the advantages of being able to account for all plant improvements, especially those which reduce the station service, allowing the same net generation to be delivered to the customer with less heat input of fuel and less CO_2 emissions as a result (all other factors considered equal).

To-date, the principal advantage espoused by those who have chosen a gross MWh basis is largely due to the fact that CEMS systems typically include only gross output in their monitoring and historian records, and due to difficulties that are encountered in properly allocating the power consumption of station service from common/shared systems at the plant. The first concern is easily remedied by deploying and keeping current an accurate measurement of net output and CO_2 emissions in the plant data historian, drawing from CEMS and generation data. Plum Point is currently proactively making significant upgrades to their monitoring and diagnostics systems and thus mapping net generation with CO_2 emissions should not be problematic. The latter concern regarding allocation of station service between multiple units is not applicable to Plum Point, being a single unit. Thus, Plum Point should utilize a net generation basis as it will more accurately quantify the benefit of all heat rate improvement projects, and therefore will encourage projects that work to reduce station service and improve plant efficiency.

b) If your recommendation is for a gross generation-based standard, then do you have any recommendations for accounting for emissions reductions attributable to technologies affecting only net efficiency?

- ***N/A***

FINAL

PLUM POINT ENERGY STATION HEAT RATE STUDY

B&V PROJECT NO. 404370
B&V FILE NO. 14.4100

PREPARED FOR

Plum Point Services

18 MARCH 2020

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1.0 Introduction

1.1 INTRODUCTION

Plum Point Services Company (Plum Point) asked Black & Veatch to support its efforts to analyze the potential response to the United States Environmental Protection Agency (EPA) Docket ID No. EPA-HQ-OAR-2017-0355, "Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program. Proposed Affordable Clean Energy (ACE) rule." Plum Point operates Plum Point Unit 1, consisting of one coal fired electric generating unit (EGU), and specifically requested that Black & Veatch develop a high-level assessment report identifying opportunities to improve plant efficiency to meet ACE proposal goals.

To meet these goals, Black & Veatch prepared a high-level description of one primary heat rate improvement (HRI) project that has 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 have been developed for each alternative.

A comprehensive assessment of the technical and economic feasibility will not be provided in this effort but should be considered in a follow-on effort under a separate phase. Follow-on studies would consist of conceptual engineering to develop more accurate performance and cost estimates for the system(s) to better determine feasibility of the options evaluated at a high level in this study.

2.0 Existing Plant Characteristics

Table 2-1 shows the existing estimated full-load efficiency parameters for Plum Point Unit 1, along with estimated net plant heat rate and CO_2 emissions rates. These data were gathered from the Plum Point Vista modeling re-calibration that was conducted in 2018 and subsequently updated in 2020.

Table 2-1 Plum Point Full-Load Data for 2020 Vista Modeling

UNIT	GROSS/ NET (MW)	NET TURBINE HEAT RATE (BTU/KWH), ACTUAL	BOILER EFFICIENCY, HHV BASIS (%)	NET PLANT HEAT RATE (BTU/KWH)	COAL BURN RATE (tph)	COAL HHV (BTU/LBM)	CO_2 EMISSIONS (tph)
Plum Point Unit 1	738.25/ 680.99	7,307	84.65	9,357	372.5	8,553	653.8
MW - megawatt; Btu/kWh - British thermal units per kilowatt-hour; Btu/lbm - British thermal units per pound.							

The data in Table 2-1 were from a test period when the unit was running a capacity test for a Heat Rate Test August 1, 2019.

The unit consists of an Ishikawajima-Harima Heavy Industries subcritical pulverized coal boiler with single reheat stage. Five mills supply the boiler with coal, and combustion air is supplied by two forced draft (FD) fans. Two bisector Ljungström air heaters are utilized for air preheating. Nitrogen oxides (NO_x) control systems installed at the unit include low-NO_x burners, a separated overfire air system, and an ammonia injection (SCR) system. Particulate control is by a cold-side fabric filter. Sulfur dioxide (SO_2) control is by a dry tower absorber scrubber. Activated carbon is injected into the flue gas ductwork to control mercury emissions.

3.0 Description of Heat Rate Improvement Alternatives

This preliminary heat rate project screening effort was developed from a high-level analysis of Plum Point Energy Station, as well as Black & Veatch's experience with similar projects. The projects depicted herein were selected from HRI projects detailed by the EPA in its ACE proposal as "BSER" projects. A detailed table summarizing the benefits and costs is included in Appendix B.

3.1 STEAM TURBINE BLADE PATH UPGRADES

Black & Veatch reviewed steam turbine blade path upgrade options. As a result of this investigation, three heat balance models of the Plum Point Energy Station steam turbine were developed:

- Base Case: Best match of the Plum Point Energy Station thermal kit heat balance at relevant conditions.
- Case 1: Only the HP (high pressure) and IP (intermediate pressure) steam path of the turbines are upgraded.
- Case 2: The entire steam path HP/IP/LP (low pressure) turbines are upgraded.

This analysis is based on the incremental improvement in steam turbine efficiency, and the differential performance between base case and upgraded scenario is the focus of the analysis. 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.

3.1.1 Base Case

The Base Case model is the best match of the thermal kit heat balance Drawing 3GMG01831, which is the maximum continuous rating (MCR) scenario. The Toshiba steam turbine for Plum Point Energy Station is a four-flow turbine with 33.5-inch last stage blade length for the LP end. The heat rejection is through a dual pressure wet surface condenser and a mechanical draft cooling tower. The steam turbine was commissioned in 2010. The Base Case model was then used to run four cases: MCR Load (corresponding to thermal kit heat balance Drawing 3GMG01831), Rated Load (corresponding to thermal kit heat balance Drawing 3GMG01832), 75 Percent of Load (corresponding to thermal kit heat balance Drawing 3GMG01833), and Minimum Load (flow corresponding to 370 megawatt [MW] gross output).

3.1.2 Case 1: HP/IP Steam Path Upgrades

In this model, the HP and IP sectional efficiencies were increased from approximately 91.3 percent and 91.2 percent to approximately 92 percent and 92.5 percent, respectively. The turbine sectional efficiencies that are considered for the upgrade option are based on a review of six turbine upgrade studies and proposals in the last four years. This potential improvement is estimated from technology upgrades and an option for additional improvements from the correction of typical operation degradation. A complete turbine inspection by an OEM is required to analyze the condition of the turbine to estimate the precise and detailed improvements of the steam turbine. This model was then used to run four cases: MCR, Rated Load, 75 Percent Load, and Minimum Load. In these cases, the boiler steam generation was reduced so that the steam turbine power output matched the values found in the corresponding cases generated by the Base Case model. The condenser pressures were kept consistent between the Base Case and upgraded models.

3.1.3 Case 2: Full Steam Path Upgrades

In this model, the HP, IP, LP-A, and LP-B turbine sectional efficiencies were raised from approximately 91.3 percent, 91.2 percent, 85.6 percent, and 89.2 percent, to approximately 92 percent, 92.5 percent, 87 percent, and 90.5 percent, respectively. As was stated in Case 1, the turbine sectional efficiencies that are considered for the upgrade option are based on a review of six turbine upgrade studies and proposals in the last four years. This potential improvement is estimated from technology upgrades and an option for additional improvements from the correction of typical operation degradation. A complete turbine inspection by an OEM is required to analyze the condition of the turbine to estimate the precise and detailed improvements of the steam turbine. This fully upgraded model was also run for four cases (MCR, Rated Load, 75 Percent Load, and Minimum Load), again with a reduction in boiler steam generation while holding the steam turbine power output to match the desired values. Review of the available Plant Information (PI) data and turbine efficiency trend appears to indicate that HP and IP turbine efficiencies are lower than the Base Case model; however, efficiency trends are based on limited data, and accuracy cannot be determined. The current performance could not be considered in the results as no recent reference PTC performance test data are available.

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 87.82 (higher heating value [HHV] basis) applies regardless of the magnitude and type of boiler upgrades that may be required. This boiler efficiency was considered on the basis of information from the Plum Point boiler performance datasheet. It is expected that there may not be a significant improvement in heat rate with a potential full steam path upgrade in the near future because of the operating age of the steam turbine.

Table 3-1 Plum Point Steam Turbine Modeling Results – MCR Case

	UNITS	BASE MODEL	UPGRADE: HP/IP	UPGRADE: HP/IP/LP
Boiler Efficiency (HHV)	%	87.82	87.82	87.82
Steam Turbine Generator (STG) Gross Output	kW	737,250	737,250	737,250
Turbine Heat Rate	Btu/kWh	7,356	7,335	7,289
Turbine Heat Rate Change	Btu/kWh	NA	-21	-67
Turbine HRI	%	NA	0.3	0.9
Boiler Heat Input (HHV)	MBtu/h	6,175	6,158	6,119
Boiler Heat Input (HHV) Change	MBtu/h	NA	-17.7	-56.2
Boiler Heat Input (HHV) Improvement	%	NA	0.3	0.9
Gross Plant Heat Rate (HHV)	Btu/kWh	8,376	8,352	8,300
Gross Plant Heat Rate (HHV) Change	Btu/kWh	NA	-24	-76
Gross Plant Heat Rate (HHV) Improvement	%	NA	0.3	0.9

MBtu/h - million British thermal units per hour.

* This boiler efficiency is based on the Plum Point boiler datasheet.

Table 3-2 Plum Point Steam Turbine Modeling Results – Rated Case

	UNITS	BASE MODEL RATED LOAD	UPGRADE: HP/IP	UPGRADE: HP/IP/LP
Boiler Efficiency (HHV)	%	87.82	87.82	87.82
STG Gross Output	kW	722,626	722,626	722,626
Turbine Heat Rate	Btu/kWh	7,364	7,343	7,297
Turbine Heat Rate Change	Btu/kWh	NA	-21	-67
Turbine HRI	%	NA	0.3	0.9
Boiler Heat Input (HHV)	MBtu/h	6,059	6,042	6,004
Boiler Heat Input (HHV) Change	MBtu/h	NA	-17.3	-54.9
Boiler Heat Input (HHV) Improvement	%	NA	0.3	0.9
Gross Plant Heat Rate (HHV)	Btu/kWh	8,385	8,361	8,309
Gross Plant Heat Rate (HHV) Change	Btu/kWh	NA	-24	-76
Gross Plant Heat Rate (HHV) Improvement	%	NA	0.3	0.9

* This boiler efficiency is based on the Plum Point boiler datasheet.

Table 3-3 Plum Point Steam Turbine Modeling Results – 75 Percent Load Case

	UNITS	BASE MODEL 75% LOAD	UPGRADE: HP/IP	UPGRADE: HP/IP/LP
Boiler Efficiency (HHV)	%	87.82	87.82	87.82
STG Gross Output	kW	541,648	541,647	541,647
Turbine Heat Rate	Btu/kWh	7,471	7,450	7,406
Turbine Heat Rate Change	Btu/kWh	NA	-21	-65
Turbine HRI	%	NA	0.3	0.9
Boiler Heat Input (HHV)	MBtu/h	4,608	4,595	4,568
Boiler Heat Input (HHV) Change	MBtu/h	NA	-12.8	-40.1
Boiler Heat Input (HHV) Improvement	%	NA	0.3	0.9
Gross Plant Heat Rate (HHV)	Btu/kWh	8,507	8,483	8,433
Gross Plant Heat Rate (HHV) Change	Btu/kWh	NA	-24	-74
Gross Plant Heat Rate (HHV) Improvement	%	NA	0.3	0.9
* This boiler efficiency is based on the Plum Point boiler datasheet.				

Table 3-4 Plum Point Steam Turbine Modeling Results – Minimum Load Case

	UNITS	BASE MODEL MINIMUM LOAD	UPGRADE: HP/IP	UPGRADE: HP/IP/LP
Boiler Efficiency (HHV)	%	87.82	87.82	87.82
STG Gross Output	kW	370,001	369,996	369,996
Turbine Heat Rate	Btu/kWh	7,641	7,620	7,575
Turbine Heat Rate Change	Btu/kWh	NA	-21	-65
Turbine Heat Rate Improvement	%	NA	0.3	0.9
Boiler Heat Input (HHV)	MBtu/h	3,219	3,210	3,192
Boiler Heat Input (HHV) Change	MBtu/h	NA	-8.8	-27.6
Boiler Heat Input (HHV) Improvement	%	NA	0.3	0.9
Gross Plant Heat Rate (HHV)	Btu/kWh	8,700	8,677	8,626
Gross Plant Heat Rate (HHV) Change	Btu/kWh	NA	-24	-74
Gross Plant Heat Rate (HHV) Improvement	%	NA	0.3	0.9
* This boiler efficiency is based on the Plum Point boiler datasheet.				

The estimated capital cost and HRI for the turbine upgrade options are as follows:

HP/IP Upgrade Only

Total Installed Capital Cost:	$18.9 million
Heat Rate (efficiency) Improvement:	0.3 percent
Error Band for Heat Rate Improvement:	(+/-) 35 percent

Full Steam Path Upgrade

Total Installed Capital Cost:	$31.3 million
Heat Rate (efficiency) Improvement:	0.9 percent
Error Band for Heat Rate Improvement:	(+/-) 35 percent

3.2 ECONOMIZER REDESIGN OR UPGRADES

The purpose of this project was to assess efficiency gains through additional flue gas heat absorption in the economizer section of the boiler through additional surface. To assess the economizer, Black &Veatch created a base case and then investigated two options: adding two or four additional tube passes to both lower economizer banks of the parallel backpass.

As a result of several discussions with Plum Point Energy Station engineering personnel, the current Electric Power Research Institute (EPRI) Vista fuel quality impact model of Plum Point Unit 1 was updated to ensure that the boiler heat transfer model matched the current configuration of the unit. 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 increase the heat transfer area of the economizer were analyzed, and these are detailed in this section. The following comments have been recorded on the feasibility of adding economizer tube surface area to Plum Point Unit 1:

- A review of the drawings that were supplied indicate there is no room to add any passes of economizer tubes to the upper economizer section. Any addition of tube passes there may require relocation of headers.
- Some room was available to add two or four passes of tube at the top of the lower economizer sections (refer to Figure 3-1).
- The economizer tubes do not have spiral fins on both lower and upper economizer sections.
- Any changes to the flue gas temperature need to be sensitive to the concern of maintaining a minimum gas temperature need to be sensitive to the concern of maintaining a minimum SCR gas inlet temperature of 510° F at all loads (the low alarm). If the SCR gas inlet temperature drops to 490° F, the ammonia flow will stop

into the SCR. Similarly, the baghouse has a low alarm of 170° F flue gas inlet temperature, and will be bypassed when sustained at 160° F for 30 minutes.

After calibrating the Vista model of Plum Point Unit 1 to 738.25 MW gross from data collected on August 1, 2019, the following scenarios were run, with the following results:

- Baseline case – SCR inlet temperature = 729° F, air heater gas outlet temperature = 318° F.
- Adding two passes to the lower economizers – SCR inlet temperature = 725° F, air heater gas outlet temperature = 316° F.
- Adding four passes to the lower economizers – SCR inlet temperature = 721° F, air heater gas outlet temperature = 314° F.

As seen from the above results, there are no constraints in meeting the minimum SCR inlet and baghouse inlet flue gas temperatures. Only minor changes were seen in the overall net turbine heat rate, due to small variations in the balance of heat absorbed by the feedwater, versus heat absorbed by the main steam and reheat steam. However, on an overall basis, adding tube surface area to the Plum Point Unit 1 lower economizers resulted in a small improvement to the heat rate:

- Baseline case – 0% difference.
- Adding two passes to the lower economizer – 0.08 percent boiler efficiency improvement, 0.001 percent net turbine heat rate improvement, 0.085 percent net plant heat rate (NPHR) improvement.
- Adding four passes to the lower economizer – 0.15 percent boiler efficiency improvement, 0.001 percent net turbine heat rate improvement, 0.155 percent NPHR improvement.
- The relative error band of the improvements indicated above is estimated to be about+/-25 percent.

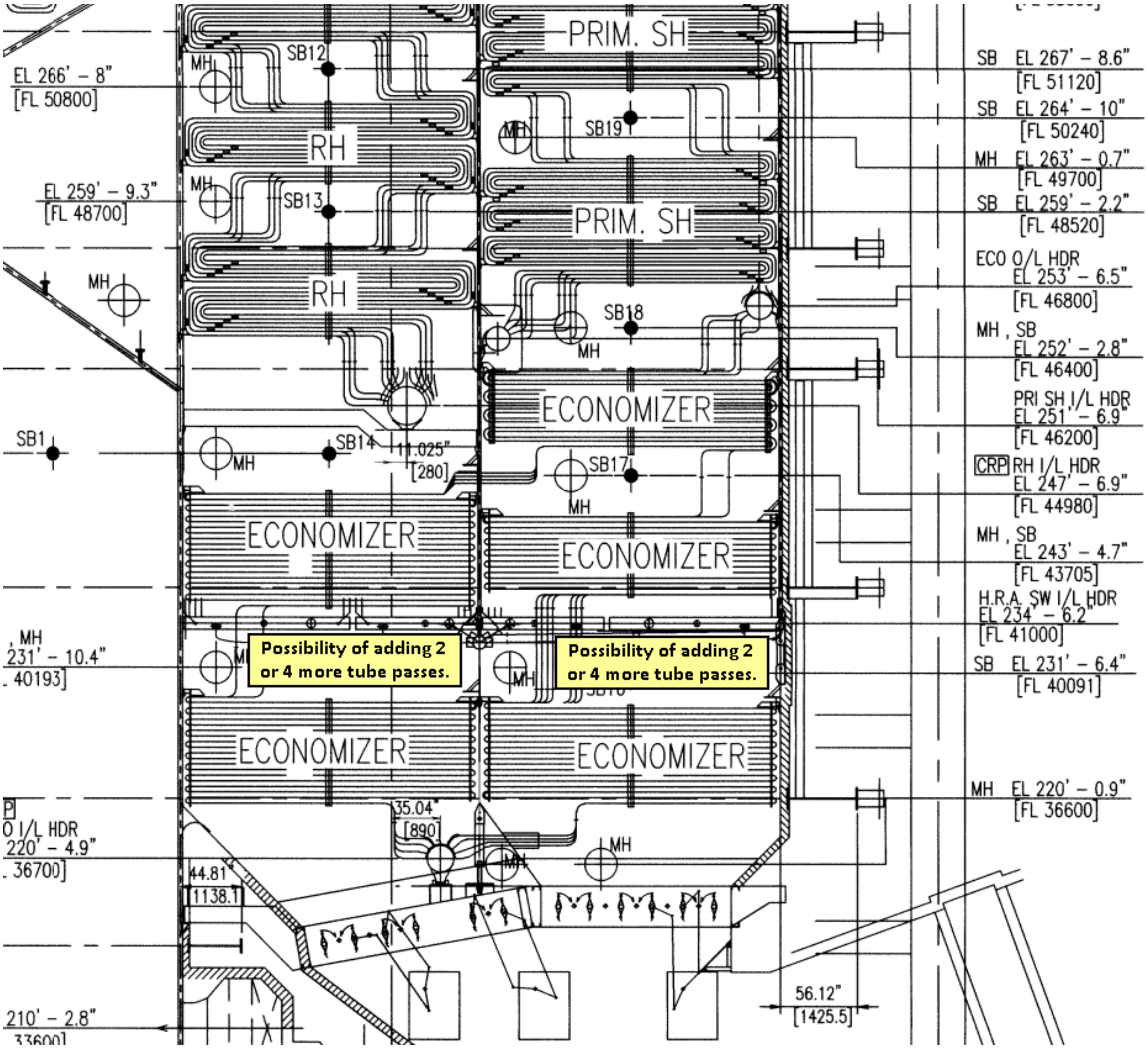


Figure 3-1 Possible Economizer Tube Pass Additions

The minimum baghouse inlet flue gas temperature was achievable for both cases. It should be noted that these analyses were conducted at full load; at lower-load operation, there is the possibility of limitation of operation of the SCR should the gas inlet temperature decrease significantly. Black & Veatch investigated the potential increase in flue gas pressure drop across the economizer banks should there be additional tube passes added, and these effects were included in our analysis of the overall net plant heat rate impacts. Overall, the effects were very minimal, which was expected given the relatively small magnitude of tube surface area changes.

While it is possible in some cases that sootblower modifications may be needed in order to accommodate, that was not investigated in detail for this portion of the study. In general, minor tube modifications to the economizer may require additional tuning or redirection of the sootblowers, and major tube modifications may require moving the sootblowers labeled SB15 and SB16 (as well as any parallel sootblowers from the other boiler side wall). A detailed assessment of the logistics and cost of moving these sootblowers is not within the scope of this study.

Should a change be made to the economizer tube surface area, the estimated costs and logistics of such a change, assuming no header relocation is needed and neglecting the loss of contract availability, is estimated to be between $900,000 and $1,500,000 for the two-pass additions, to over $2,200,000 for the four-pass 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

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

Excessive air heater and flue gas duct leakage present additional risks beyond degradation in NPHR, however. Air in-leakage also results in a tempering of flue gas, causing corrosive flue gas components to condense on air heater cold-end baskets and ductwork components, resulting in degradation of equipment materials. Therefore, reducing air heater and flue gas duct leakage rates will improve both the unit's NPHR and overall equipment life, reducing capital investments for repair and alleviating operation and maintenance (O&M) costs. Other negative impacts of high air in-leakage include the following:

- Higher flue gas velocities due to additional flue gas mass flow, reducing the effectiveness and life expectancy of air quality control equipment.
- Reduced life expectancy of ductwork, dampers, expansion joints, fans, and other balance-of-plant draft system equipment.
- 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 the air heater), causing flue gas to be closer to the acid dew point and increasing the potential for equipment corrosion throughout flue gas draft system.

The following subsections provide further discussions of air heater and leakage control upgrades to improve the heat rate. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of heat rate improvement projects and provide typical information and results for such projects that can be used to assess and further screen the potential benefit of the project for the Plum Point Power Plant. Future Phase 2 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 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 Plum Point air heaters are regenerative Ljungström trisector air heaters with rotating baskets in a vertical-shaft orientation, with two air heaters in parallel and normally operating. 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.

Testing done in February of 2019 by Storm Technologies showed the leakage across the A air heater to be 11.1 percent, and the leakage across the B air heater to be 4.2 percent, resulting in an average across both air heaters of 7.65 percent. While the average leakage is representative of successful efforts to maintain good leakage control practices, the significant difference between two identical system indicates that some adjustments could be made to balance the flows through the two trains, thereby evening the leakage rates across both air heaters. The plant has indicated that the air heaters have not experienced any fouling from ammonium bisulfate, popcorn ash, or calcium deposits, but the imbalance between the two systems indicates that the A air heater may have some plugging in its baskets or other issues (e.g., mechanical or structural issues). Further inspection of the air heaters and analysis would be recommended to determine the nature of potential issues with air heater A.

The air heaters were installed with a leakage control system and duplex seals, which are modern design features for air heaters. Even though the A air heater is in excess of 11.1 percent, the system's design is stated to be for 6.4 percent, which is toward the lower end of industry experience. Since the current average leakage rate is 7.65 percent, and the unit is already equipped with a leakage control system and duplex seals, additional modifications such as brush seals should have a nominal effect in further reducing the leakage rates across the air heaters; therefore, no benefits are expected to Plum Point's NPHR from any air heater modifications. It is recommended that the A air heater be inspected in the next outage, and any equipment failures be corrected to meet the original design.

3.3.2 Draft System Ductwork and Equipment Casing

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 will operate at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakage will increase the duty of the combustion air fans resulting 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. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans, resulting 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 ductwork 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 gases condensing on ductwork components. Condensed acid gases 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 aforementioned testing program conducted by Storm Technologies Inc. also evaluated duct leakage from the SCR inlet (economizer outlet) to the air heater outlet, and there is noticeable in-leakage across the B duct, with the calculated leakage to be 4.21 percent according to the oxygen concentration. 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 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.

For both the SCR, air heater, and surrounding ductwork, the leakage percentages are considered to be reasonable for the age of this equipment, and Black & Veatch has not assessed any NPHR impacts regarding reducing air in-leakage for that equipment. However, Black & Veatch still encourages Plum Point to consider performing the activities described in this section to continue to find draft system leakage points and repair them when possible.

3.4 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 large electrically driven rotating equipment provide many co-benefits, the largest of which is improved part-load efficiency and performance. This benefit is greatest at low load, and 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, to the point that some equipment from manufacturers are approved for use, and have been installed, in nuclear power plants for critical equipment such as reactor coolant and recirculation pumps. Part of this increased reliability comes from the development of technology to allow the VFD equipment to remain in operation if one or multiple insulation-gate bipolar transistor (IGBT) power cells fail by automatically bypassing the bad cell, or cell(s), 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:

- Replace existing rotating equipment coupling with resilient elastomeric block-shaft couplings to ensure no electrically induced torsional forces are transferred to the fan rotor. This means the existing equipment must be de-coupled from the motor, and then realigned with the new coupling.
- Upgrade the lube oil system as necessary.
- Construct new VFD enclosure foundations.
- Provide new VFD enclosures and heat exchangers.
- Replace the power supply cables between existing switchgear to the new VFD enclosure. Install new cables from the VFD enclosure to the motor.
- For smaller units, the VFD control enclosure and cabinets will also be smaller with reduced pre-outage time requirements. It should be noted that the air cooled VFD equipment can further reduce equipment installation and maintenance costs.

The rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps (BFPs), circulating water pumps, and the large draft fans for handling combustion air and flue gas (primary air [PA], FD, and ID fans).

3.4.1 Boiler Feed Pumps

Plum Point has a booster pump, motor, and main BFP on the same train. The booster pump and motor are both single speed; there is a fluid drive on the main feed pump. There is also a gearbox that increases the speed of the main feed pump from approximately 1,800 revolutions per minute (rpm) to approximately 5,400 rpm. The VFD analysis for the BFPs is performed on the basis that the fluid drive is operated to transmit the greatest amount of power to the main feed pump.

Plum Point has two main BFPs, with a fluid drive and two booster pumps driven by the same motor. The main BFPs are Flowserve 75CHTA-4, and each pump has a rated capacity of 5,244 gallons per minute (gpm) at 8,285 feet of head and 5,371 rpm. The booster pumps are Ingersoll-Dresser 10 HDX 31 and have a rated capacity of 6,065 gpm at 900 feet of head and 1,785 rpm. A fluid drive allows the main pump to run at varied speeds, while the booster pump runs at a single speed.

Full load operating conditions suggest that the BFP Train A is operating at 5,354 rpm with a discharge flow rate of 5,127 gpm and a static pressure rise of 7,316 feet. Given the speed and flow rate the pump is operating at, a static pressure rise of 7,585 feet would be expected. According to the operating conditions, the pump train is currently producing 3.5 percent less head than expected by the design curve. The pumps no longer lie on the initial operating curve, which suggests that degradation has occurred. Refer to Figure 3-2.

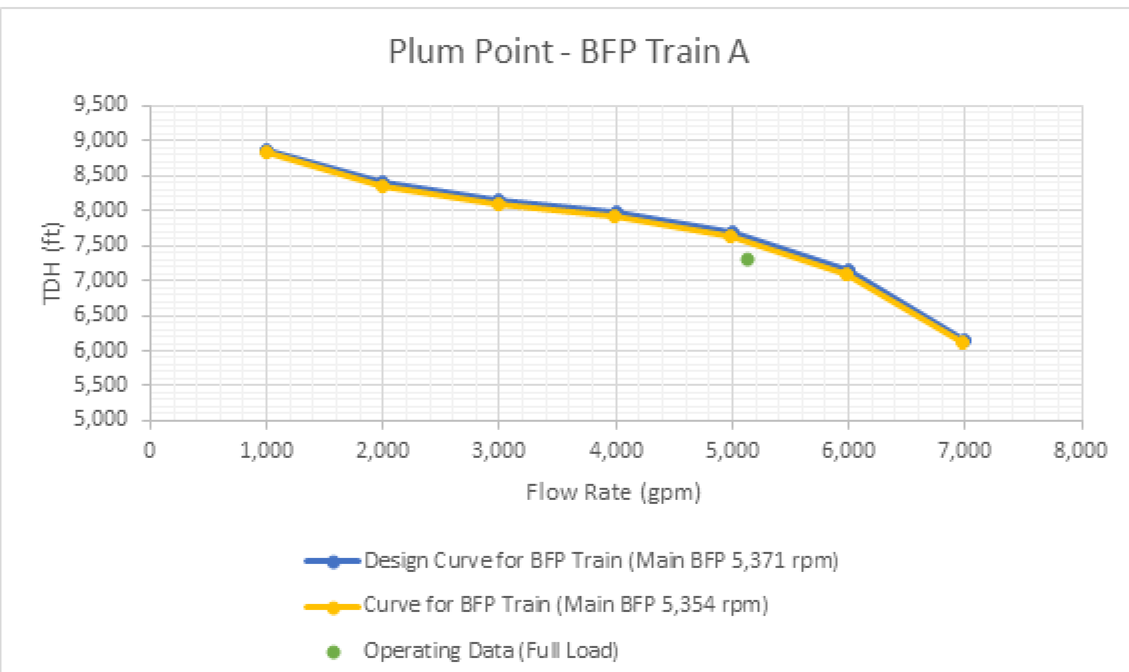


Figure 3-2 Plum Point BFP Train A Comparison

Full load operating conditions suggest that the BFP Train B is operating at 5,354 rpm with a discharge flow rate of 5,491 gpm and a static pressure rise of 7,322 feet. Given the speed and flow rate the pump is operating at, a static pressure rise of 7,275 feet would be expected. According to the operating conditions, the pump train is currently producing 0.65 percent more head than expected by the design curve. Though the increase could be due to instrumentation errors, these values do not suggest degradation in this pump. Refer to Figure 3-3.

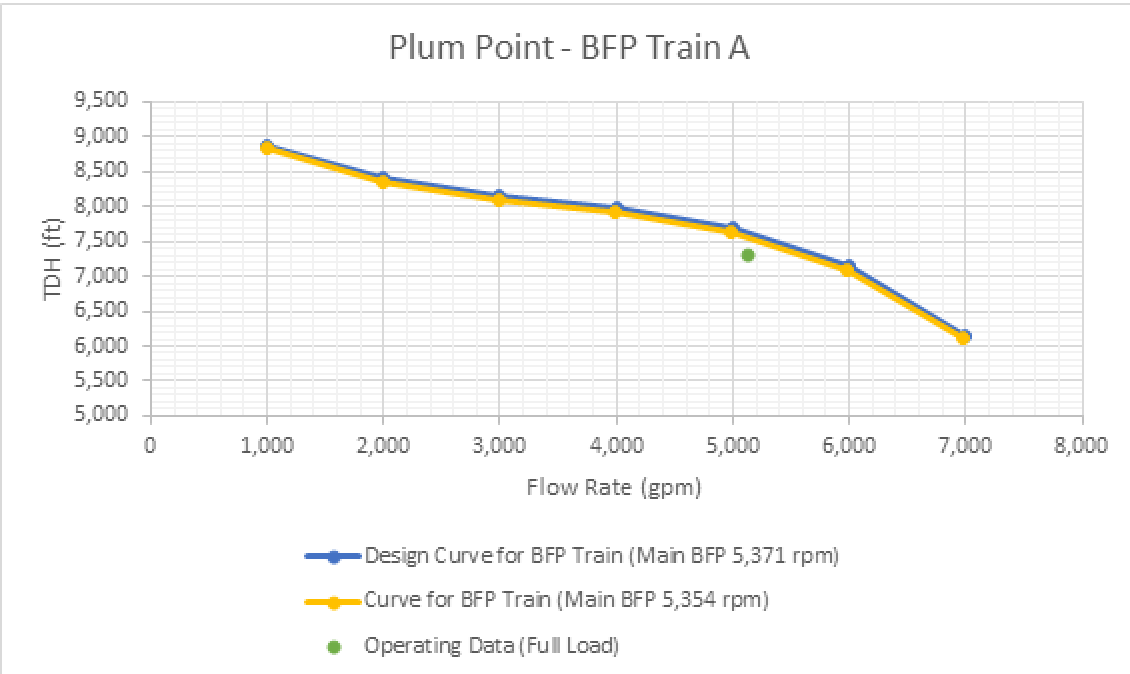


Figure 3-3 Plum Point BFP Train B Comparison

3.4.1.1 Boiler Feed Pumps VFD Analysis

According to available information and operating data, the Plum Point BFP auxiliary power consumption benefit is estimated to be a worsening of 0.4 MW for both pumps at full load (680 MW), but an improvement by 1.8 MW at low load (335 MW). Refer to Figures 3-4 and 3-5, which illustrates the current BFP train operation and future variable speed operation with the addition of VFDs. The VFD analysis allowed a reduction of the pump speeds by 1.25 percent at full load and 26 percent at low load. These pumps operate near their highest efficiency point at full load, but there are significant savings potential at low load, even with the fluid drives still in place.

The evaluated impacts of this project are as follows:

VFD Deployment for BFP Trains	
Total Installed Capital Cost:	$2.2 million for both motors
Auxiliary Power Reduction:	Full load (680 Net MW): -0.4 MW

	Low load (335 Net MW): 1.8 MW
Heat Rate (efficiency) Improvement:	Full load: -0.06 percent
	Low load: 0.53 percent
Estimated Additional Annual O&M Cost:	$6,000 per unit
Error Band for Heat Rate Improvement:	(+/-) 35 percent

The plant mentioned it had investigated adding VFDs to the BFP trains, and it was estimated to be $1.1 million to add a VFD to each one.

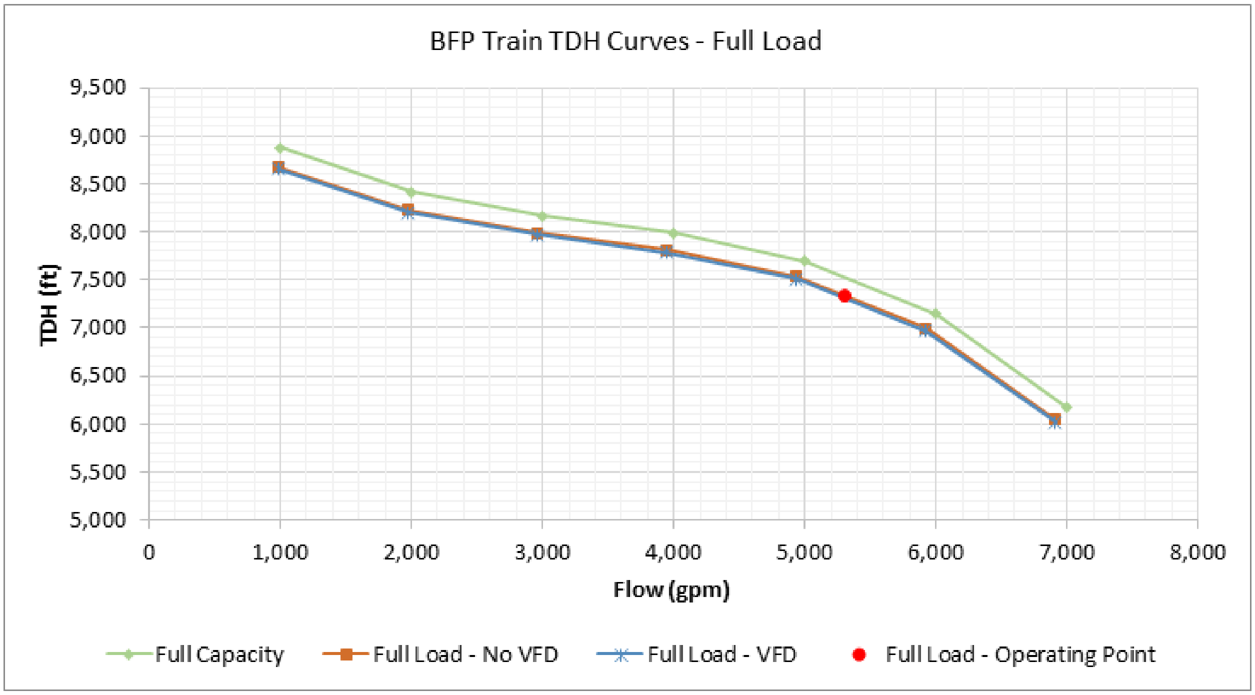


Figure 3-4 Plum Point BFP Train Curves – Full Load Variable Speed Comparison

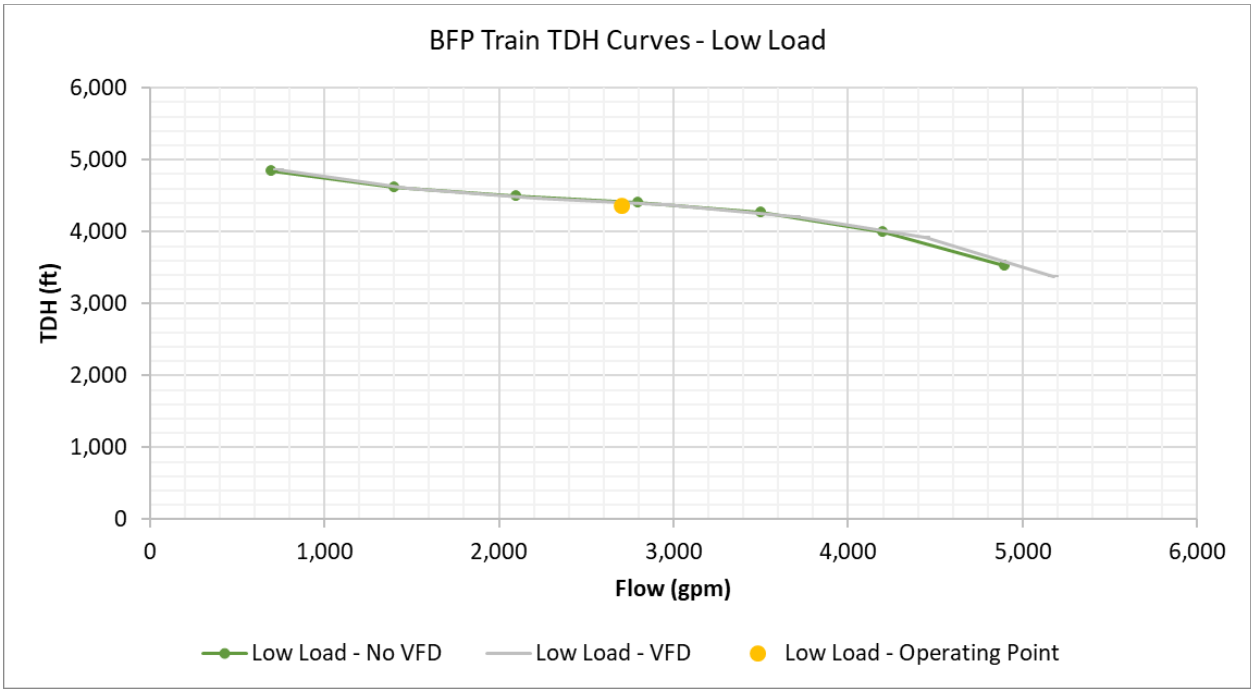


Figure 3-5 Plum Point BFP Train Curves – Low Load Variable Speed Comparison

3.4.2 Circulating Water Pumps

The circulating water system includes two 50 percent capacity vertical circulating water pumps driven by 3,400 horsepower motors. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow during periods of part load operation or during colder months. 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). These studies have shown that, for most of the time, it is more advantageous to operate the circulating water pumps and cooling tower fans at full capacity to maintain the lowest temperature to the condenser and lowest condenser back 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.

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. These water sources cool during winter months, and there is no concern of freezing. Since the heat rejection system on Plum Point uses a cooling tower, the installation of VFD systems on circulating water pumps will not be evaluated further.

3.4.3 Large Draft Fans

Plum Point has ID, FD, and PA fans that will be evaluated with this study. The ID fans are currently two speed; the FD and PA fans are both currently single speed. For all fan analyses, the fans were assumed to be in a typical cleanliness condition, mid-way between regular scheduled outages.

3.4.3.1 Induced Draft Fans

According to available information and operating data, the Plum Point ID fan auxiliary power consumption benefit is estimated to be 2.2 MW for both fans at full load (680 MW) and 2.7 MW at low load (335 MW). For the analysis, it was assumed that the fans were operated at high speed only when the plant is near full load and drop to the low speed of the motor when at low or intermediate loads. Refer to Figures 3-6 and 3-7, which illustrate the current ID fan operation and Figure 3-8, which illustrates future variable speed operation with the addition of VFDs.

The evaluated impacts of this project are as follows:

VFD Deployment for ID Fans	
Total Installed Capital Cost:	$4.61 million for both fans
Auxiliary Power Reduction:	Full load (680 Net MW): 2.2 MW
	Low load (335 Net MW): 2.7 MW
Heat Rate (efficiency) Improvement:	Full load: 0.32 percent
	Low load: 0.8 percent
Estimated Additional Annual O&M Cost:	$6,000 per unit
Error Band for Heat Rate Improvement:	(+/-) 35 percent

The estimated furnish and erect price for a VFD system for the Plum Point ID fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, demolition of the existing variable speed fluid drive, engineering, installation, and contingency. It should also be noted that limited available space immediately around the rotating equipment would not affect the installation of VFD systems as the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

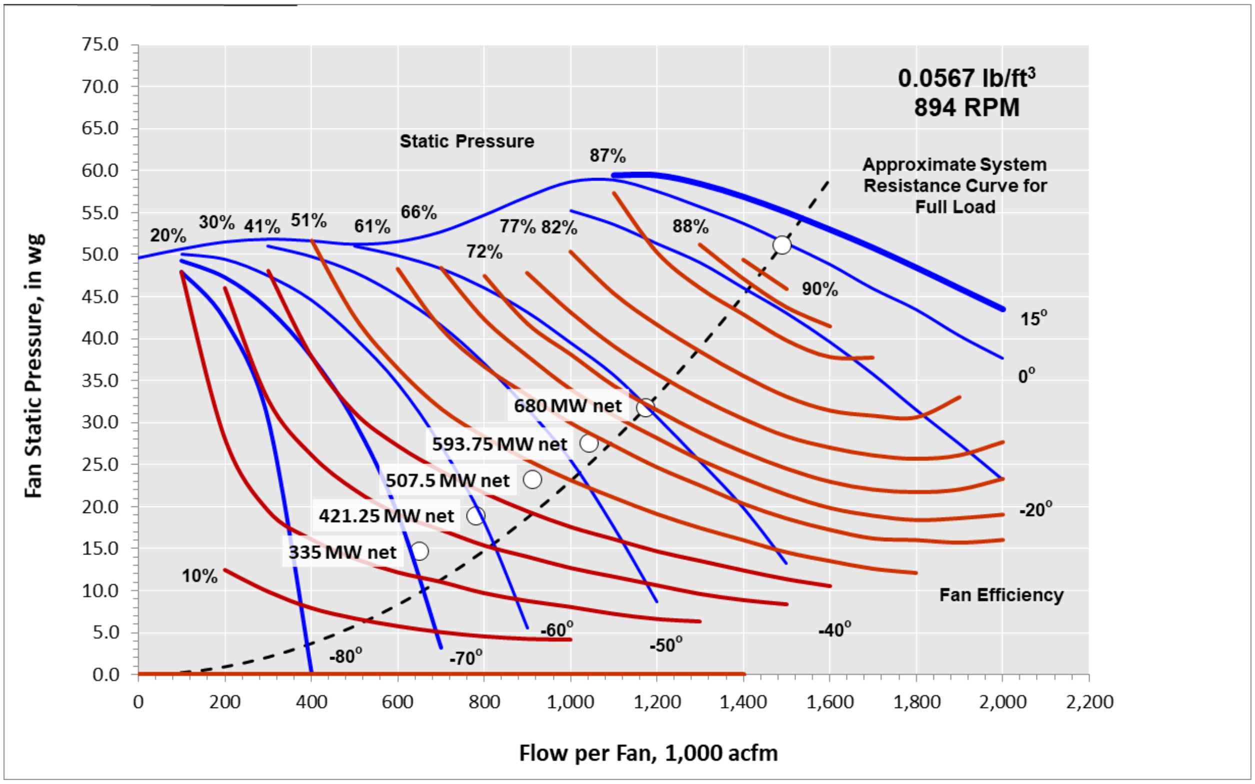


Figure 3-6 Plum Point ID Fan Operation – High Speed Operation

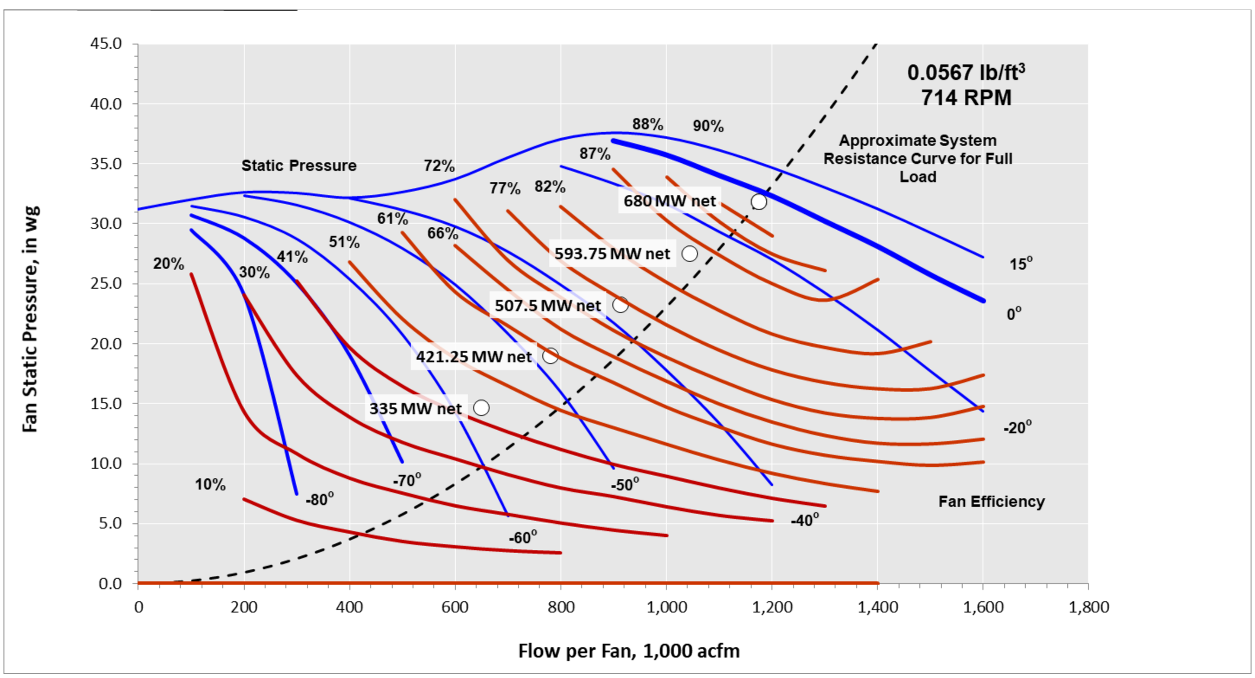


Figure 3-7 Plum Point ID Fan Operation – Low Speed Operation

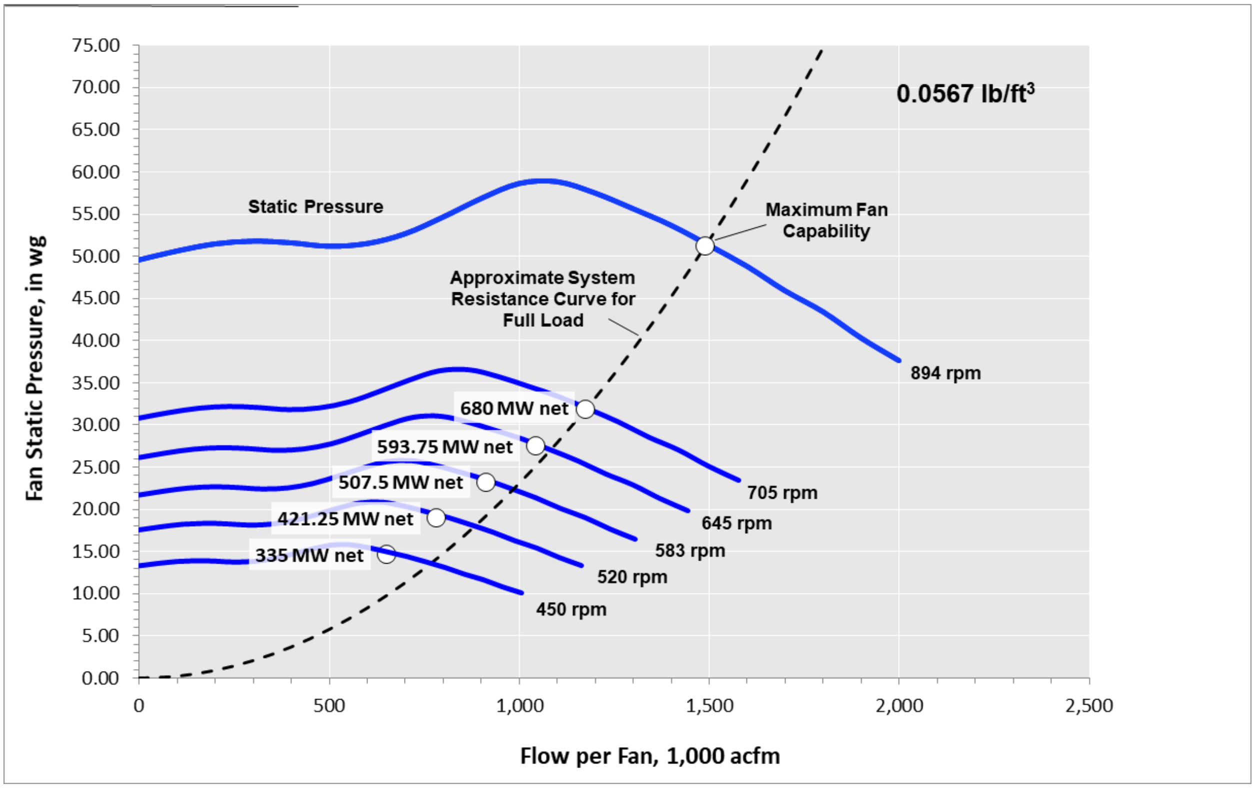


Figure 3-8 Plum Point ID Fan Operation – Variable Speed Control

3.4.3.2 Forced Draft Fans

According to available information and operating data, the Plum Point FD fan auxiliary power consumption benefit is estimated to be 0.4 MW for both fans at full load (680 MW) and 1.2 MW at low load (335 MW). Refer to Figures 3-9 and 3-10, which illustrate the current FD fan operation and future variable speed operation with the addition of VFDs.

The evaluated impacts of this project are as follows:

VFD Deployment for FD Fans	
Total Installed Capital Cost:	$1.88 million for both fans
Auxiliary Power Reduction:	Full load (680 Net MW): 0.4 MW
	Low load (335 Net MW): 1.2 MW
Heat Rate (efficiency) Improvement:	Full load: 0.06 percent
	Low load: 0.36 percent
Estimated Additional Annual O&M Cost:	$6,000 per unit
Error Band for Heat Rate Improvement:	(+/-) 35 percent

The estimated furnish and erect price for a VFD system for the Plum Point FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, demolition of the existing variable speed fluid drive, engineering, installation, and contingency. It should also be noted that limited available space immediately around the rotating equipment would not affect the installation of VFD systems as the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

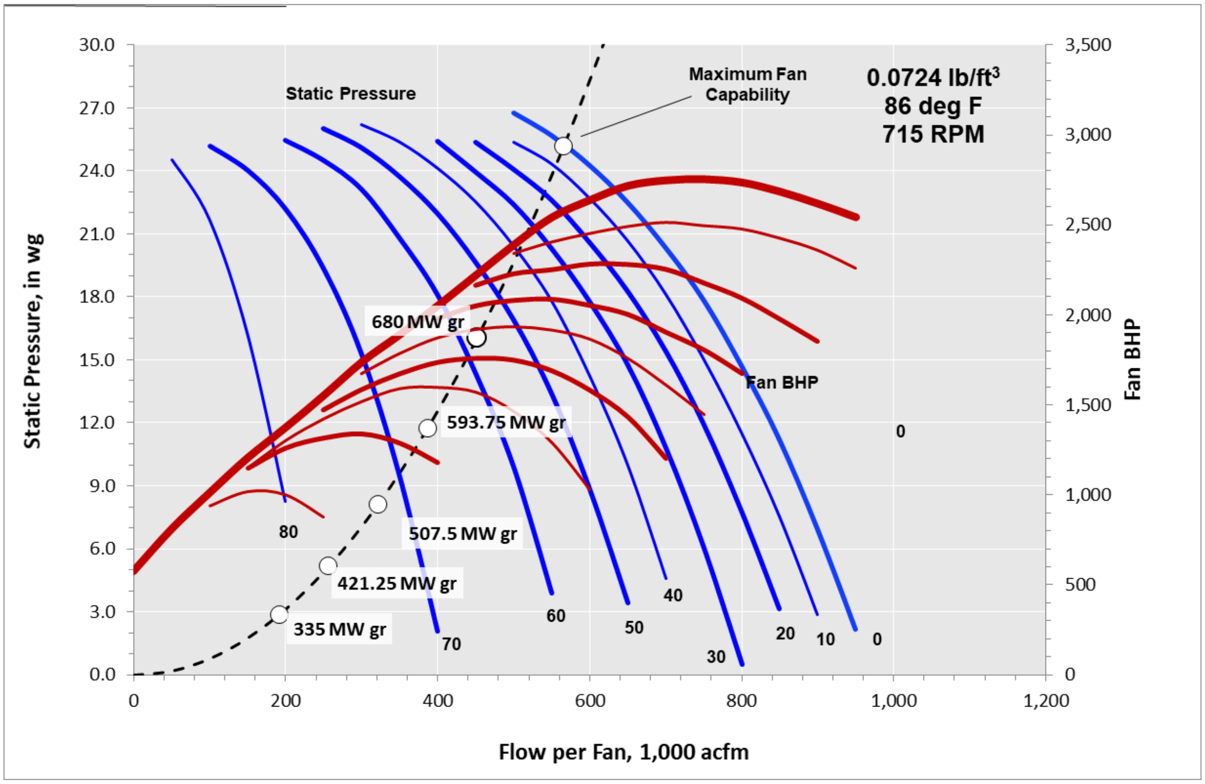


Figure 3-9 **Plum Point FD Fan Operation – Inlet Vane Control Operation**

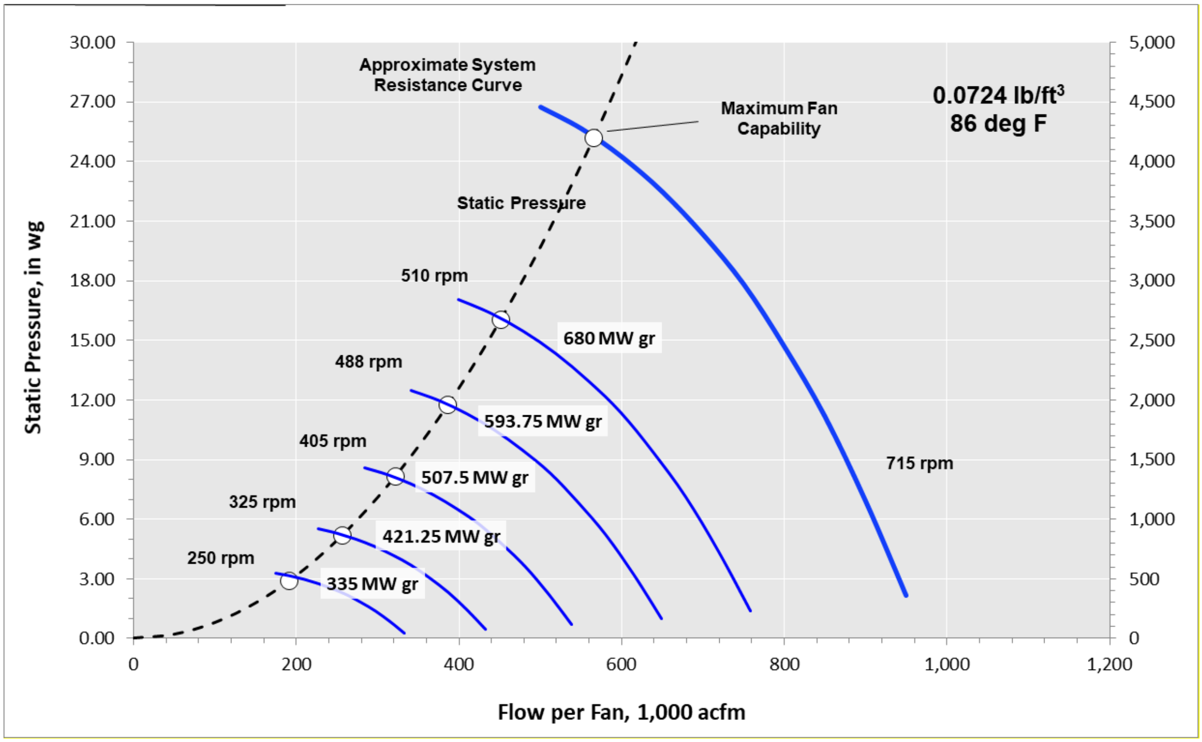


Figure 3-10 Plum Point FD Fan Operation – Variable Speed Control

3.4.3.3 Primary Air Fans

According to available information and operating data, the Plum Point PA fan auxiliary power consumption benefit is estimated to be 0.6 MW for both fans at full load (680 MW) and 1.0 MW at low load (335 MW). Refer to Figures 3-11 and 3-12, which illustrate the current PA fan operation and future variable speed operation with the addition of VFDs.

The evaluated impacts of this project are as follows:

VFD Deployment for PA Fans	
Total Installed Capital Cost:	$2.69 million for both fans
Auxiliary Power Reduction:	Full load (680 Net MW): 0.6 MW
	Low load (335 Net MW): 1.0 MW
Heat Rate (efficiency) Improvement:	Full load: 0.09 percent
	Low load: 0.3 percent
Estimated Additional Annual O&M Cost:	$6,000 per unit
Error Band for Heat Rate Improvement:	(+/-) 35 percent

The estimated furnish and erect price for a VFD system for the Plum Point PA fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, demolition of the existing variable speed fluid drive, engineering, installation, and contingency. It should also be noted that limited available space immediately around the rotating equipment would not affect the installation of VFD systems as the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

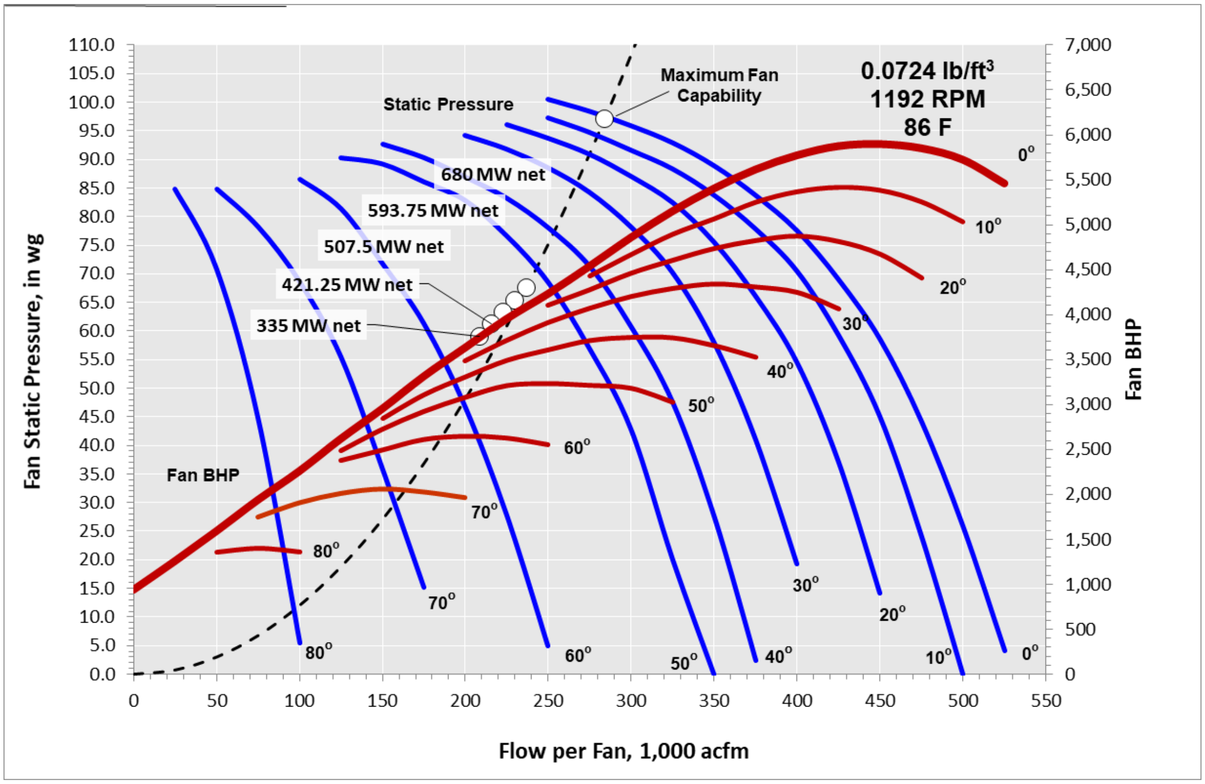


Figure 3-11 Plum Point PA Fan Operation – Inlet Vane Control Operation

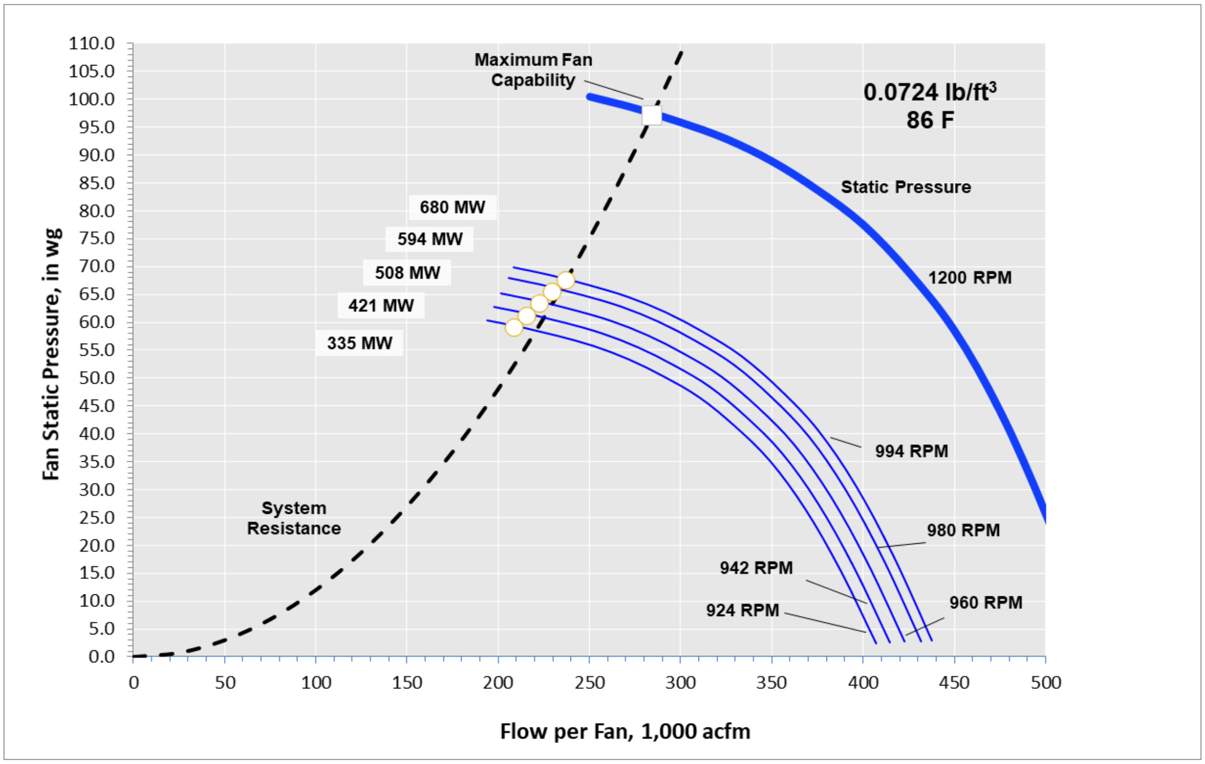


Figure 3-12 Plum Point PA Fan Operation – Variable Speed Control

3.5 NEURAL NETWORK DEPLOYMENT

The purpose of this project would be to tune the system to allow for the reduction of boiler outlet O_2 concentration without increasing NO_x emissions, carbon monoxide (CO) emissions, and unburned combustible losses. Adaptive neural net systems have the greatest effect when controlling air flow and fuel mixtures down to a fine level. The full benefits are only realized 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 measurements and 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 and fuel mixture through a grid of CO measurements.

This unit has five pulverizers (one spare), each with six associated burners for a total of 30 burners. Air control through the inner vane of the air registers is available and could be utilized by a neural net system, but the balancing of fuel to individual burners is done manually and, thus, is not available for neural net control. Additionally, there are 10 secondary air inlet dampers and four overfire air/side air port inlet dampers that could be utilized in a neural net system. There is also the ability to control for feeder speed biasing, coal fineness, and mill outlet temperatures.

From Black & Veatch experience, boiler combustion tuning can typically gain 0.25 percent in boiler efficiency, dependent often on lowering the O_2 concentration. A review of historical data for this unit suggests that a 0.2 to 0.25 percent improvement could be achievable with a proper balancing of O_2. Other objectives, such as CO and NO_x control, would have to be considered and would contribute to defining a more optimum level of O_2.

Refer to Figure 3-13. Hourly averages of high load performance with C Mill offline (preferred mill configuration) from 2018 are shown in the plot. Selected economizer outlet O_2 (percent) is plotted against stack CO (parts per million [ppm]) and boiler efficiency (percent). As expected, there is a linear best-fit curve showing an improvement in boiler efficiency as O_2 levels decrease due to lower sensible heat losses. However, as O_2 drops below 2.45 percent, there is a noticeable shift down in the boiler efficiency data set of nearly approximately 0.2 percent. Additionally, at these reduced O_2 levels, the "floor" of the CO data set is shifted up by 10 to 20 ppm. These data suggest that poorer combustion may have occurred when O_2 was less than 2.45 percent. There is an individual data point on Figure 3-12 showing the average O_2 and average boiler efficiency of the entire data set at 2.64 and 86.4 percent, respectively. A case could be made that a properly tuned neural net system could have helped the unit lower the O_2 closer to 2.475 to 2.5 percent and achieved a boiler efficiency increase from 86.4 to 86.6 percent. Additionally, there is a noticeable cluster of data points with boiler efficiency values in the 86.6 to 86.8 percent range, suggesting an even slightly higher ceiling for improving efficiency with a neural net system.

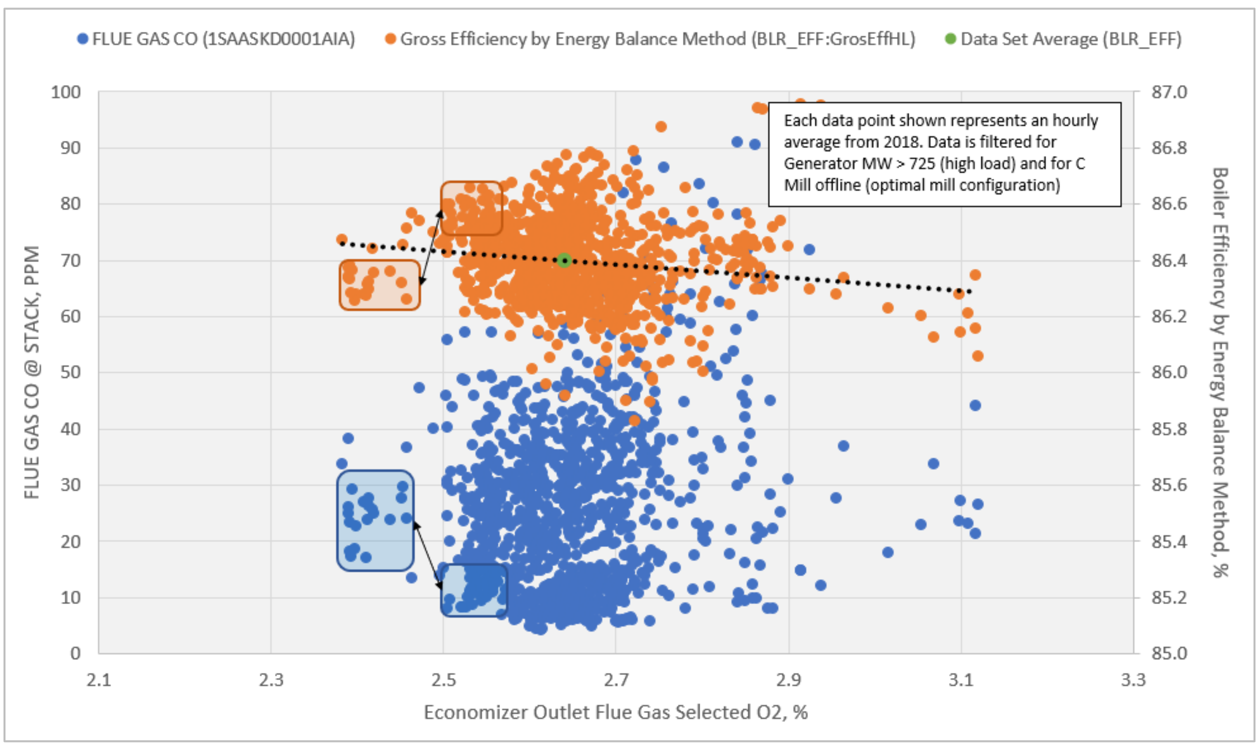


Figure 3-13 Plum Point Economizer Outlet O_2 Versus Stack CO and Boiler Efficiency, 2018

To compare to the data from 2018, a more recent data set is shown on Figure 3-14. High load hourly-averages from 11/4/2019 through 1/30/2020 were chosen because minimal moves of the secondary air inlet dampers and overfire/side air port inlet dampers were made during this time frame. This suggests that changes in CO and boiler efficiency across the O_2 range are better controlled for manual tuning efforts that the plant engages in from time to time. Select O_2 levels are mostly below 2.5 percent in this data set, and as O_2 is further reduced, there is a mostly linear correlation with lower boiler efficiency.

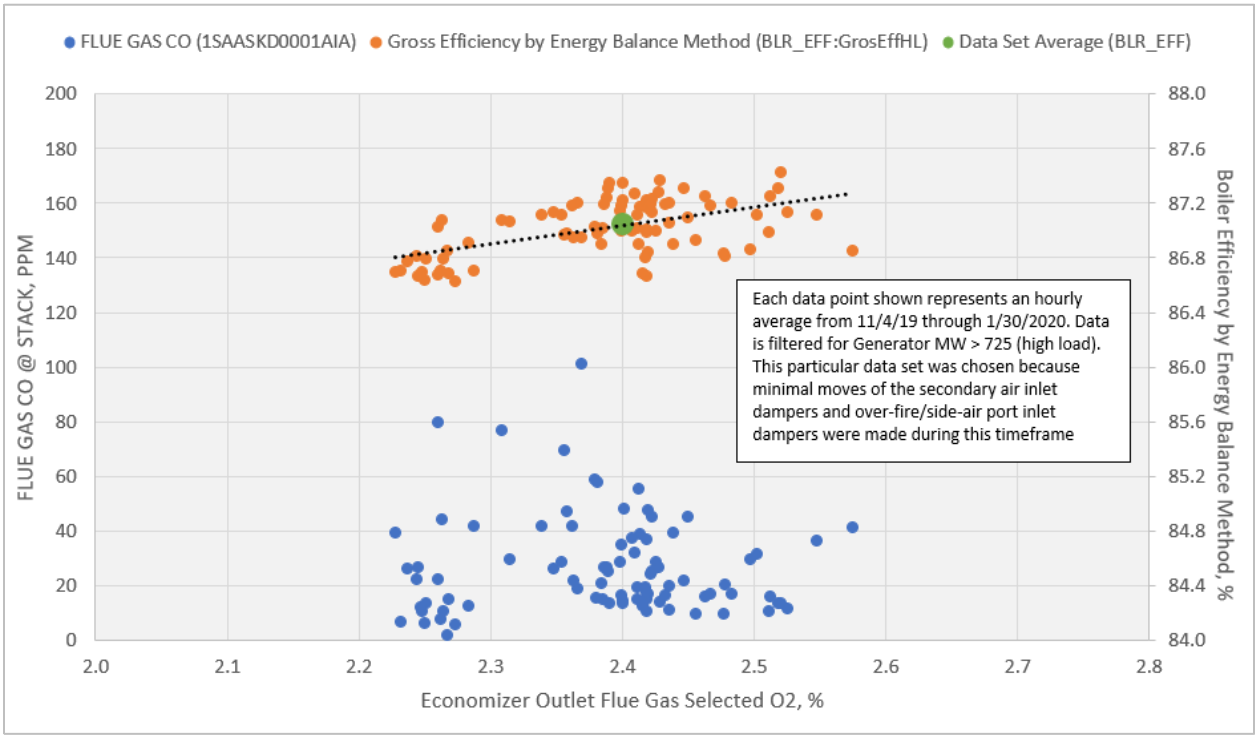


Figure 3-14 Plum Point Economizer Outlet O_2 Versus Stack CO and Boiler Efficiency, 2019-2020

Multiple objectives, some often in direct competition with others, would need to be appropriately balanced by a neural net system. This does not guarantee that a more optimal O_2 level would be at the low end of the historical data range, but data suggest there is room to improve efficiency and NPHR without significantly increasing CO.

Total Installed Capital Cost:	$450,000
Heat Rate (efficiency) Improvement:	0.20 percent
Error Band for Heat Rate Improvement:	(+/-) 15 percent

3.6 INTELLIGENT SOOTBLOWING DEPLOYMENT

The purpose of this project would be to reduce the required sootblowing flow by installing an integrated intelligent sootblower control system. This system would utilize heat flux sensors, hanger strain gauges, and process data to determine the areas needed to be cleaned. By only cleaning the “dirtier” areas and by better prioritizing unit objectives, sootblowing flow would be reduced and tube life potentially extended. Additional HRIs could be seen by achieving target steam temperatures with reduced superheat and reheat spray flows and reduced boiler exit gas temperatures.

This unit has 44 total steam soot blowers for the boiler, two steam soot blowers for the air heaters (one for each cold end), and four water cannons (two for the front wall, two for the rear wall). One boiler sootblower operation with one air heater operation is allowed. The water cannons can operate simultaneously with the boiler and air heater sootblower operations. Steam for sootblowing is extracted from the header of the secondary superheater outlet or cold reheat steam piping. For the available process data to make an intelligent sootblowing system more effective, this unit has 24 heat flux sensors in the water cannon zone, and it has reliable instrumentation for multiple gas temperatures, steam temperatures, spray flows, and furnace gas differential pressures. There are also numerous tube bank outlet metal temperatures for the finishing superheat, secondary superheat, tertiary superheat, and reheat sections. Taken all together, the instrumentation available for this unit is more than adequate for a successful intelligent sootblowing system.

The client communicated that the current sootblowing strategy is to run manual sequences; specifics such as which sequences are run and to what frequency depend on the control room operator on the shift. The client indicated there is a tendency to run the same sequence multiple times until an objective is met. On the operations side, a monthly preventive maintenance task is in place to monitor sootblower operation and steam pressure and to make pressure adjustments as needed.

A review of historical data shows a positive correlation between unit load (MW) and total sootblower steam flow (kpph). Daily averages of generator MW plotted against total sootblower steam flow for data going back to September 2017 are shown on Figure 3-15. One observation from this plot is that throughout the load range, there is a normal spread of approximately 5 kpph in steam flow for a given MW. It is not fully clear why this spread exists, but it does suggest the potential for an intelligent sootblowing system to keep steam flow averages more toward the bottom side of that curve without negatively affecting heat rate or unit reliability objectives. Additionally, the client has stated that operational challenges with sootblowing have been more present with the unit not operating at baseload as much as it had in previous years. Figure 3-16 shows a time-based plot of unit load and sootblower steam flow since September 2017 and highlights this significant change in the load profile since the spring of 2019. Referring back to Figure 3-15, of some interest is that the sootblower steam flow is not significantly different between 500 and 700 generator MW. Given limited historical runtime at mid-loads, this might be a load range where sootblowing optimization could reduce steam flow without negatively affecting other unit objectives.

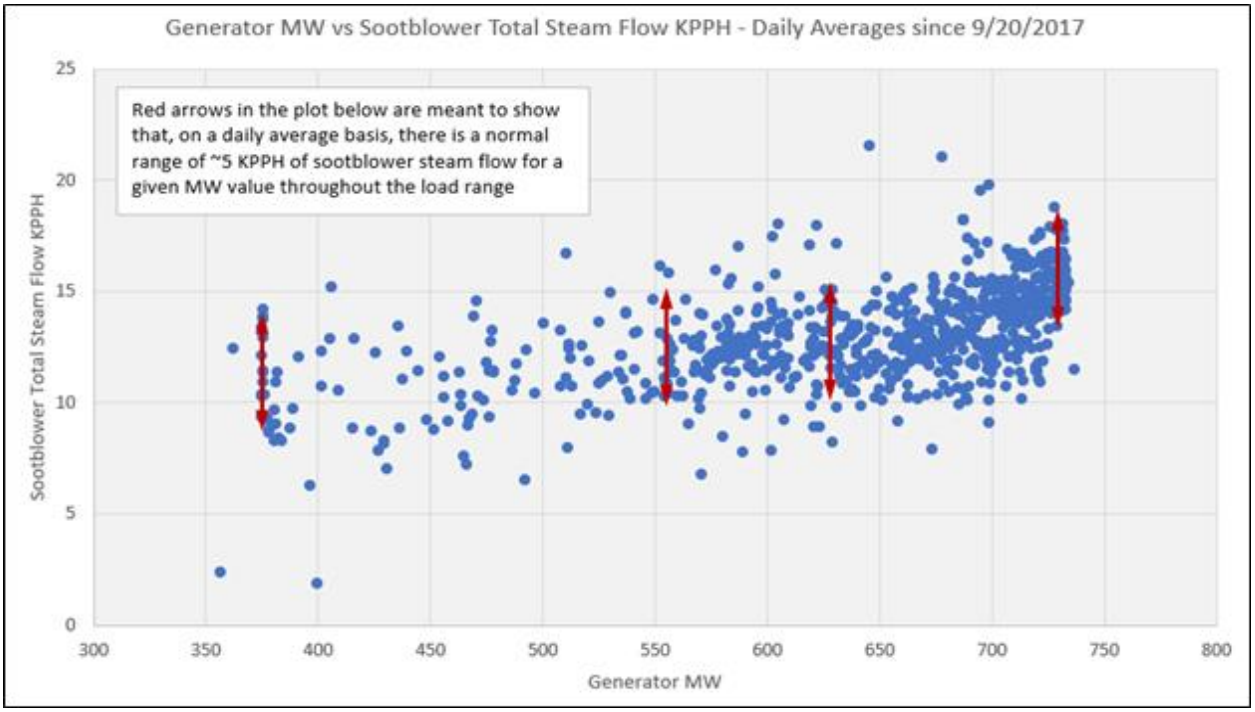


Figure 3-15 **Plum Point Generator MW Versus Sootblower Total Steam Flow KPPH**

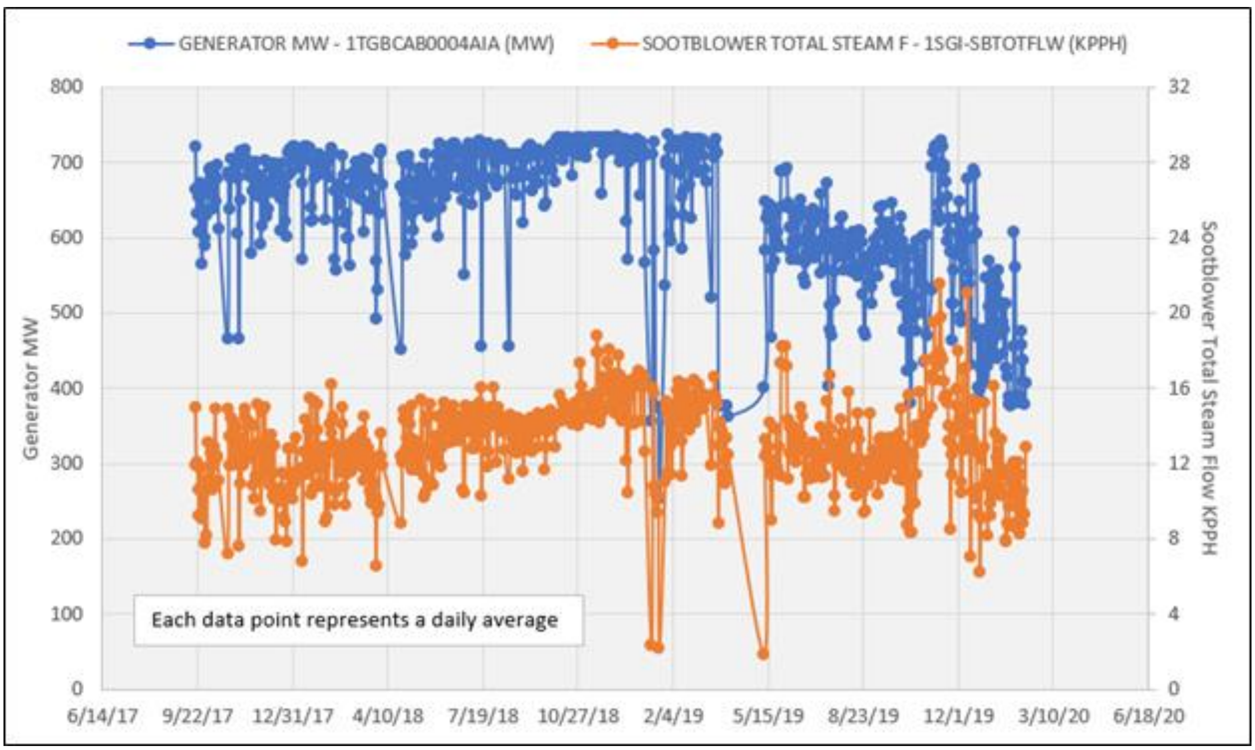


Figure 3-16 **Plum Point Generator MW and Sootblower Total Steam Flow KPPH Daily Averages since September 2017**

One objective directly related to sootblowing is keeping the SCR gas inlet temperatures within a range of 690 to 720° F at higher loads. Figure 3-17 shows hourly averages of the six economizer outlet flue gas temperatures (these are the temperatures heading into the SCR) for generator MW more than 700 over the past year. For the "A" side average, 7.3 percent of all the hours shown in the plot were below 690° F, and 16.4 percent were above 720° F. For the "B" side average, only 0.5 percent were below 690° F, but 18 percent were above 720° F. This suggests that there is some difficulty in maintaining temperatures in the appropriate range with the current sootblowing strategy. An integrated sootblowing control system would potentially be able to reduce these instances.

Figure 3-17 Plum Point SCR Inlet Gas Temps Filtered for High Load (Hourly Averages)

Total Installed Capital Cost:	$350,000
Heat Rate (efficiency) Improvement:	0.03 percent
Error Band for Heat Rate Improvement:	(+/-) 35 percent

3.7 IMPROVED OPERATION AND MAINTENANCE PRACTICES

The purpose of this project would be to improve O&M practices for three particular areas of focus: HRI training, on-site appraisals for identifying additional HRIs, and improved condenser cleaning strategies.

3.7.1 Heat Rate Improvement Training

Black & Veatch conducts heat rate awareness training that 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 HRIs of 0.1-0.5 percent in the first year of implementation.

3.7.2 On-Site Heat Rate Appraisals

This item, which is 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 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 HRI and 4 MW capacity improvement.
- An audit of terminal temperature difference (TTD) and 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 percent (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 due to debris in the heater.
- An analysis of 19 different truck coals supplied to a power plant found not only that seven of the coals were unprofitable to burn but that 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 due to high-temperature sodium-based fouling, which cost the unit an additional 1.2 percent in heat rate on an annual basis due to the increased number of starts and stops from fouling-related outages.
- A long-term analysis of plant continuous emissions monitoring system 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 to 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.

3.7.3 Improved Condenser Cleaning Strategies

The current cleaning strategy for the HP and LP condensers involves the manual removal of debris during outages. Additionally, a biodetergent (ChemTreat product CL-456) is used at the cooling tower. A shock feed is done 3 days per week, which translates to a total of approximately 60 gallons. The plant chemist stated that this biodetergent (1) minimizes the potential for cooling tower fouling, (2) minimizes the potential for biofilm development, and (3) keeps the heat exchange surfaces cleaner, allowing for better heat transfer.

Installing a ball tube cleaning system is most often effective in maintaining near design levels of tube cleanliness and should reduce the need for more aggressive cleaning. This should also help mitigate condenser back pressure heat rate impacts due to fouling.

A review of data since September 2017 shows both HP and LP condenser performance have been remarkably consistent over time, and fouling does not appear to be a routine issue. Figure 3-18 plots hourly averages of HP condenser shell selected pressure (pounds per square inch absolute [PSIA]) against the average circ water inlet temperature into the HP condenser (°F). Eight data sets capturing performance before and after fall and spring outages are shown. Table 3-5 shows estimated shell pressures that are based on best-fit linear regression curves. Throughout the inlet temperature range, pressures are all within approximately 5 percent. A similar situation is shown on Figure 3-19 and Table 3-6 for the LP condenser.

With the use of a biodetergent at the cooling tower, and given the historically consistent performance for both condensers, the quantification for an improved cleaning strategy will be minimal. A best-case scenario could help the unit achieve shell pressures toward the lower end of the range of the curves shown on the figures. This might gain the unit an approximately 0.35 percent HRI.

Total Installed Capital Cost:	$500,000
Heat Rate (efficiency) Improvement:	0.35 percent
Error Band for Heat Rate Improvement:	(+/-) 35 percent

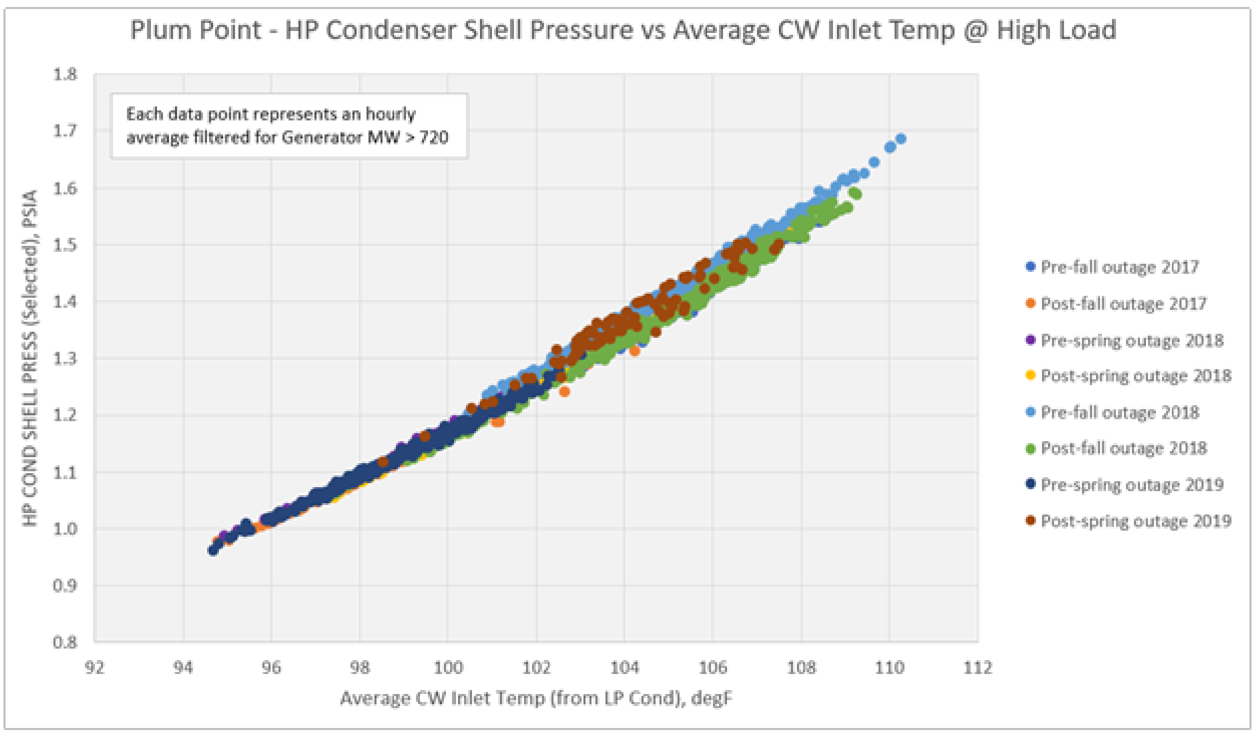


Figure 3-18 Plum Point HP Condenser Shell Pressure versus Average Circulating Water Inlet Temperature

Table 3-5 Plum Point HP Condenser Shell Pressure Linear Regression Best Fit Curve

	AVERAGE CWIT (DEG F)	BEST-FIT HP COND SHELL PRESS (PSIA | INHGA)
Pre-Fall Outage 2017	106	1.43 | 2.90
Post-Fall Outage 2017	106	1.38 | 2.81
Pre-Spring Outage 2018	106	1.43 | 2.90
Post-Spring Outage 2018	106	1.43 | 2.90
Pre-Fall Outage 2018	106	1.46 | 2.97
Post-Fall Outage 2018	106	1.43 | 2.91
Pre-Spring Outage 2019	106	1.41 | 2.87
Post-Spring Outage 2019	106	1.45 | 2.96

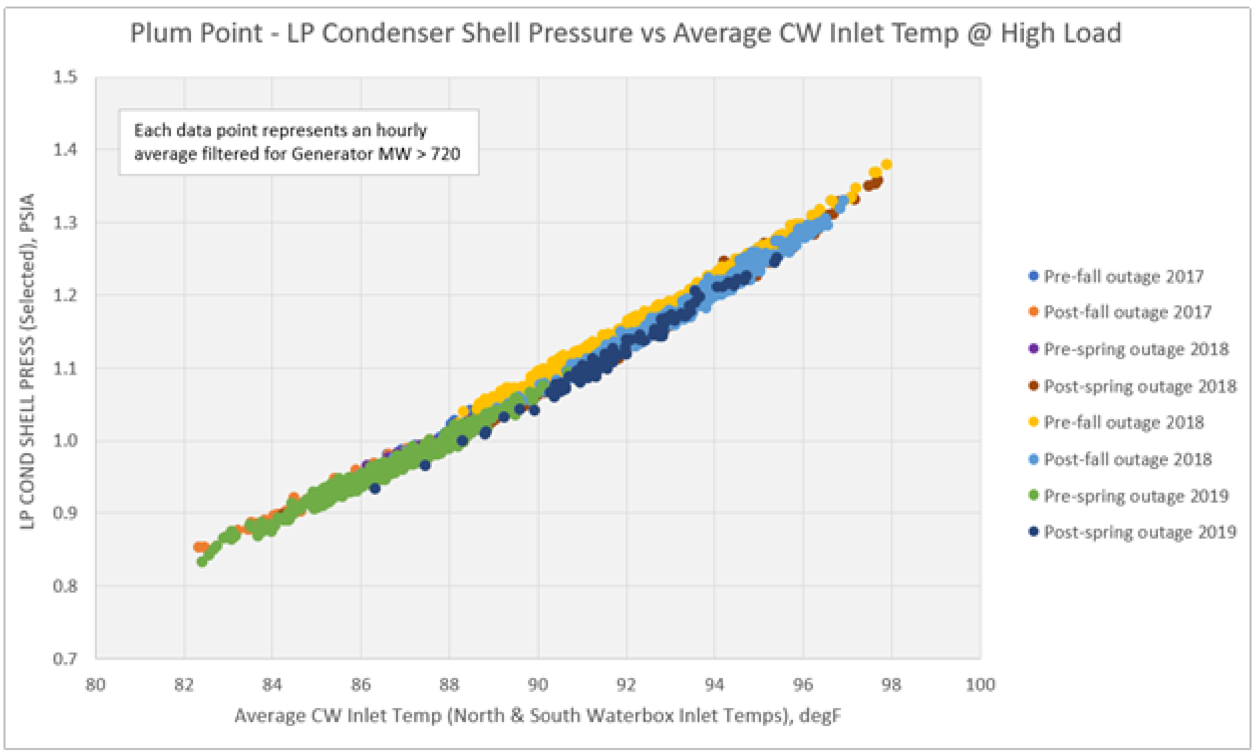


Figure 3-19 Plum Point LP Condenser Shell Pressure Versus Average Circulating Water Inlet Temperature

Table 3-6 Plum Point LP Condenser Shell Pressure Linear Regression Best Fit Curve

	AVERAGE CWIT (DEG F)	BEST-FIT LP COND SHELL PRESS (PSIA | INHGA)
Pre-Fall Outage 2017	96	1.24 | 2.52
Post-Fall Outage 2017	96	1.24 | 2.52
Pre-Spring Outage 2018	96	1.27 | 2.59
Post-Spring Outage 2018	96	1.28 | 2.60
Pre-Fall Outage 2018	96	1.29 | 2.63
Post-Fall Outage 2018	96	1.27 | 2.60
Pre-Spring Outage 2019	96	1.23 | 2.51
Post-Spring Outage 2019	96	1.27 | 2.59

4.0 Performance and CO_2 Reduction Estimates

High level plant performance estimates were used to determine the average annual CO_2 reduction. These performance benefits are summarized in Appendix B, Tables B-1 and B-2. 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 Tables B-1 and B-2.

The annual CO_2 reductions shown in Table B-1 were estimated using plant performance basis shown in Table 4-1 and assumed a baseline 71.2 percent net capacity factor, which was kept constant for all units across the coal generating fleet. Gross and net capacity and the average annual net plant heat rate were provided by S&P Global, and the coal burn rate was estimated at 740 MW gross output.

Table 4-1 Basis for CO_2 Reduction Estimates – 71.2 Percent Net Capacity Factor for 2012-2018

GROSS/NET CAPACITY (MW)	NET CAPACITY FACTOR (%)	AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH)*	FUEL HEAT INPUT (MBTU/Y)*	LBM CO_2/ MBTU (HHV)*	ANNUAL CO_2 (TON/Y)*
740/680	71.2%	9,790	43,918,356	207.0	4,546,055
* This figure differs from Table 2-1 because they are annual average values, rather than full load values.					

The annual CO_2 reductions shown in Table B-2 were determined using a 5 year look ahead net capacity factor estimate that was provided by Plum Point Energy Station. For Plum Point Unit 1, this net capacity factor estimate was 65.8 percent. Gross and net capacity were unchanged, although the average annual NPHR did vary due to the difference in the net capacity factor (also provided by S&P Global, and the coal burn rate was estimated at 740 MW gross output.) See Table 4-2 for these look ahead values.

Table 4-2 Basis for CO_2 Reduction Estimates – 65.8 Percent Net Capacity Factor (Future)

GROSS/NET CAPACITY (MW)	NET CAPACITY FACTOR (%)	AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH)	FUEL HEAT INPUT (MBTU/Y)	LBM CO_2/ MBTU (HHV)	ANNUAL CO_2 (TON/Y)
740/680	65.8%	9,839	43,150,543	205.2	4,427,003
* This figure differs from Table 2-1 because they are annual average values, rather than full load values. This was based on 11 months out of the year, 12 months where available.					

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 [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 and B-2, 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 engineer, procure, and construct (EPC) project execution strategy. Pricing was based on a similar project pricing or the Black & Veatch 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.

6.0 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 the following subsections.

6.1 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 Plum Point Unit 1 can have a significant impact on the ability to achieve the expected efficiency gains and associated reduced CO_2 emissions.

6.1.1 Operating Load and Load Factor

Plants that operate with a low average output will have lower efficiency compared to 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 due to 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.

6.1.2 Transient Operation

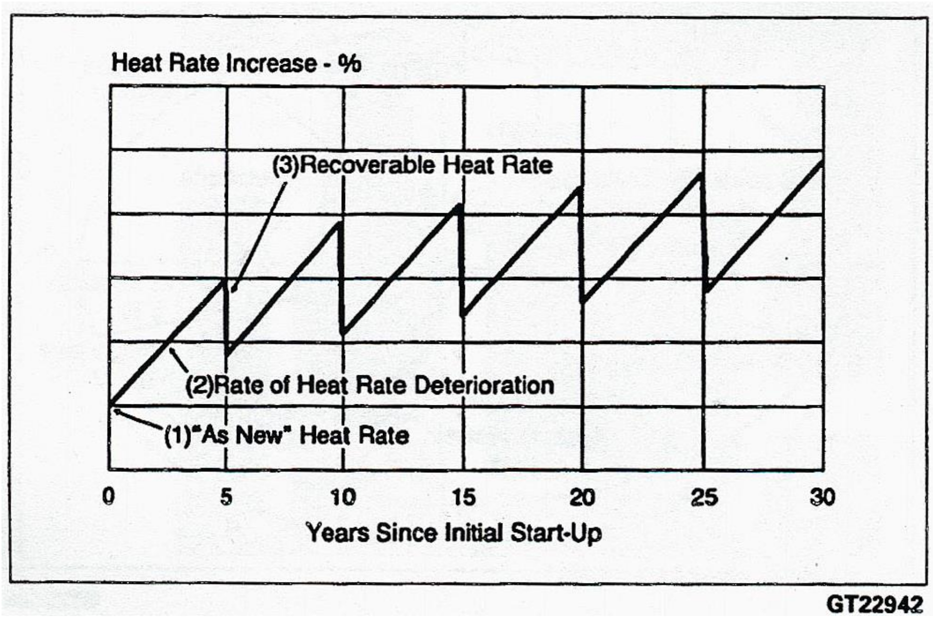
The greater the number of transients from steady-state operating conditions that the plant experiences, the greater the impact to annual efficiency. During each of these transients, the plant will not be operating at peak performance. The influence of increasing renewable energy can affect the frequency 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.

6.1.3 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.

6.2 DETERIORATION

Figure 6-1 illustrates the characteristic of 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.

6.3 PLANT MAINTENANCE

As well as ensuring plant availability, a key requirement of plant maintenance is to maintain peak operating efficiency. Improved maintenance, 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 achieved without increased or more complicated plant maintenance. Table B-1 and B-2 include an order of magnitude rating of comparative operating and maintenance cost impact associated with each of the given projects.

6.4 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 lbm of CO_2 emission/MBtu of fuel burned.

6.5 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 due to 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)
ASSET360	A comprehensive remote monitoring, diagnostic, and predictive platform that is utilized throughout Plum Point Service's coal units.
BFP	Boiler Feed Pump
BSER	Best System of Emission Reduction
Btu	British Thermal Unit
Btu/kWh	British Thermal Unit per Kilowatt-Hour
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DCA	Drain Cooler Approach
EGU	Electrical Generating Unit
EPA	United States Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FD	Forced Draft
gpm	Gallons per minute
h	Hour
HHV	Higher Heating Value
HP	High Pressure
HRI	Heat Rate Improvement
ID	Induced Draft
IEEE	Institute of Electrical and Electronics Engineers
IGBT	Insulation – Gate Bipolar Transistor
in. HgA	Inches of Mercury – Absolute
IP	Intermediate Pressure
kpph	Kilopounds per Hour
kW	Kilowatt
kWh	Kilowatt-hour
lbm	Pound
LP	Low Pressure
MBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt Hour
NO_x	Nitrogen Oxides
NPHR	Net Plant Heat Rate

O&M	Operations and Maintenance
PA	Primary Air
ppm	Parts per Million
PTC	Performance Testing Code
rpm	Revolutions per Minute
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
STG	Steam Turbine Generator
TTD	Terminal Temperature Difference
V	Volt
VFD	Variable Frequency Drive
Vista	The EPRI Vista fuel quality impact analysis program, which is used to model all of the Plum Point Service's coal units.
y	Year

Appendix B. Capital Cost and Performance Estimates

Table B-1 Preliminary EPC Capital Cost Estimate (in 2020 Dollars) and First Year Performance Benefits (71.2 Percent Net Capacity Factor for 2012-2018)

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 Steam Path Upgrade	18,900	0.30	29.4	131,755	13,638	1385.82	Low
Steam Turbine	Full Steam Path Upgrades.	31,300	0.90	88.1	395,265	40,914	765.01	No change
Economizer	Minor Redesign With Additional Tube Passes.	1,200	0.085	8.3	37,331	3,864	310.55	No change
Economizer	Major Redesign With Additional Tube Passes.	2,200	0.16	15.2	68,073	7,046	312.22	No change
Air Heater/Duct Leakage	Air Heater Retrofit Of Movable Sector Plates + Seal Replacement	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Air Heater/Duct Leakage	Air Heater Retrofit Of Duplex Sealing System With New Baskets And Moveable Sector Plates + Seal Replacement	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	2,200	0.30	29.8	133,784	13,848	158.87	No change
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	4,610	0.62	60.4	270,818	28,033	164.45	No change
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	1,880	0.25	24.0	107,776	11,156	168.52	No change
Variable Frequency Drive (VFD) Upgrades	Primary Air Fans	2,690	0.22	21.5	96,524	9,991	269.23	No change
Neural Network	Deployment Of A Neural Network For Combustion Control And Boiler Excess Air Reduction (0.25% Reduction In Excess O_2)	450	0.2	19.6	87,837	9,092	49.49	Low/Med
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	0.03	2.9	13,176	1,364	256.63	Low
Improved O&M Practices	Heat Rate Improvement Training.	15	0.30	29.4	131,755	13,638	1.10	Low
Improved O&M Practices	On-Site Heat Rate Appraisals.	N/A	N/A	N/A	N/A	N/A	N/A	NA
Improved O&M Practices	Improved Condenser Cleaning Strategies.	500	0.35	34.3	153,714	15,911	31.42	Low

Table B-2 Preliminary EPC Capital Cost Estimate (in 2020 Dollars) and First Year Performance Benefits (65.8 Percent Future Net Capacity Factor)

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 Steam Path Upgrade	18,900	0.30	29.5	129,452	13,281	1423.08	Low
Steam Turbine	Full Steam Path Upgrades.	31,300	0.90	88.6	388,355	39,843	785.58	No change
Economizer	Minor Redesign With Additional Tube Passes.	1,200	0.085	8.4	36,678	3,763	318.90	No change
Economizer	Major Redesign With Additional Tube Passes.	2,200	0.16	15.3	66,883	6,862	320.61	No change
Air Heater/Duct Leakage	Air Heater Retrofit Of Movable Sector Plates + Seal Replacement	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Air Heater/Duct Leakage	Air Heater Retrofit Of Duplex Sealing System With New Baskets And Moveable Sector Plates + Seal Replacement	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	2,200	0.30	30.0	131,445	13,486	163.14	No change
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	4,610	0.62	60.7	266,084	27,299	168.87	No change
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	1,880	0.25	24.1	105,891	10,864	173.05	No change
Variable Frequency Drive (VFD) Upgrades	Primary Air Fans	2,690	0.22	21.6	94,836	9,730	276.47	No change
Neural Network	Deployment Of A Neural Network For Combustion Control And Boiler Excess Air Reduction (0.25% Reduction In Excess O_2)	450	0.2	19.7	86,301	8,854	50.82	Low/Med
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	0.03	3.0	12,945	1,328	263.53	Low
Improved O&M Practices	Heat Rate Improvement Training.	15	0.30	29.5	129,452	13,281	1.13	Low
Improved O&M Practices	On-Site Heat Rate Appraisals.	N/A	N/A	N/A	N/A	N/A	N/A	NA
Improved O&M Practices	Improved Condenser Cleaning Strategies.	500	0.35	34.4	151,027	15,495	32.27	Low

Plum Point Energy Station
Post Office Box 567
2732 South County Road 623
Osceola, Arkansas 72370
(870) 563-4018 FAX (870) 563-5053

April 24, 2020

Division of Environmental Quality
Office of Air Quality- Policy and Planning Branch
5301 Northshore Drive
North Little Rock, AR 72118

Re: Information Request to Plum Point Energy Station Regarding Anticipated Future Operating Characteristics

Dear Sir or Madam,

Please see the attached response to ADEQ's request for anticipated future operating characteristics of Plum Point Energy Station. The attachment includes data from publicly available sources and escalation factors based on industry experience.

If you have any questions, please contact Matt Gray at 870-563-5072.

Thank you,

Matt Gray

Matt Gray
Environmental Specialist

Plum Point Energy Station Future Operating Characteristics

Year	Net Capacity Factor	Net Generation	Gross Generation	CO2 Emissions	Heat Input	Heat Rate	Fuel Price	Fuel Carbon Content	Fixed O&M	Variable O&M
	(%)	(MWh)	(MWh)	(tons)	(MMBtu)	(Btu/kWh)	($/ton delivered)	(%)	($)	($)
2010	27.88	1,671,778	2,223,529	2,144,550	20,451,327	10,266	$39.39	47.2	5,362,407	34,103,284
2011	71.21	4,270,099	4,649,454	4,635,764	44,222,855	9,871	$39.32	47.6	6,563,591	83,670,730
2012	74.19	4,461,027	4,866,532	4,944,118	47,155,541	9,910	$44.61	47.8	19,991,688	84,228,178
2013	68.08	4,082,324	4,461,848	4,326,893	41,274,121	10,118	$45.73	47.8	20,256,104	109,695,106
2014	61.79	3,705,106	4,029,412	3,888,067	37,074,851	9,854	$46.49	47.8	18,736,356	72,075,705
2015	69.21	4,150,127	4,520,777	4,194,113	40,884,367	9,756	$46.58	47.8	15,429,148	95,557,766
2016	78.25	4,704,987	5,121,496	4,788,943	46,679,518	9,651	$47.71	47.7	18,026,702	101,614,003
2017	59.99	3,597,001	3,920,388	4,007,904	39,071,302	9,761	$47.03	47.9	31,202,167	82,556,662
2018	86.77	5,202,634	5,656,924	5,672,345	55,288,792	9,478	$38.36	47.2	18,203,285	109,447,274
2019	65.78	3,944,609	4,317,736	4,427,001	43,150,542	9,750	$49.12	47.4	18,161,289	88,069,489
2020	72.70	4,371,461	4,764,838	4,681,593	45,098,352	9,660	$49.86	47.5	18,757,378	90,960,099
2021	74.89	4,490,303	4,894,374	4,794,529	46,065,242	9,638	$50.60	47.6	19,267,312	93,432,921
2022	70.39	4,220,885	4,600,712	4,535,530	43,412,265	9,684	$51.36	47.8	19,845,331	96,235,909
2023	72.50	4,347,511	4,738,733	4,657,259	44,461,023	9,663	$52.13	47.9	20,440,691	99,122,986
2024	74.68	4,490,205	4,894,267	4,795,744	45,663,135	9,640	$52.91	48.1	21,111,594	102,376,393
2025	70.20	4,209,260	4,588,041	4,524,355	42,916,337	9,686	$53.71	48.2	21,685,529	105,159,576
2026	72.30	4,335,538	4,725,683	4,645,749	43,965,746	9,665	$54.51	48.3	22,336,095	108,314,363
2027	74.47	4,465,604	4,867,453	4,770,786	45,165,889	9,642	$55.33	48.3	23,006,178	111,563,794
2028	70.01	4,209,169	4,587,941	4,525,576	42,810,563	9,688	$56.16	48.3	23,761,285	115,225,532
2029	72.11	4,323,598	4,712,668	4,634,271	43,855,573	9,667	$57.00	48.3	24,407,254	118,338,270
2030	74.27	4,453,306	4,854,048	4,758,963	45,052,411	9,644	$57.69	48.3	25,139,472	118,338,270
2031	69.81	4,186,108	4,562,805	4,502,098	42,586,925	9,690	$58.38	48.3	25,893,656	118,338,270
2032	71.91	4,323,504	4,712,565	4,635,490	43,865,555	9,669	$59.08	48.3	26,743,535	118,662,484
2033	67.59	4,052,989	4,417,708	4,374,128	41,358,620	9,713	$59.79	48.3	27,470,580	118,338,270
2034	69.62	4,174,579	4,550,239	4,491,015	42,480,549	9,692	$60.51	48.3	28,294,697	118,338,270
2035	65.44	3,924,104	4,277,225	4,250,227	40,169,375	9,735	$61.23	48.3	29,143,538	118,338,270

The table above takes into account leap years whereas analyses do not to preserve correlations.

***Data Sources** EIA 923, EPA CEMS, FERC Form 1, S&P Global and ABB Energy Velocity databases

*ALL Public available information