WV ACE Partial State Plan

Appendix J

Black & Veach “Longview Unit 1 Heat Rate Study”

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FINAL

LONGVIEW UNIT 1 HEAT RATE STUDY

B&V PROJECT NO. 406009
B&V FILE NO. 14.410

PREPARED FOR

Longview Power

11 AUGUST 2020

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1.0 Executive Summary

1.1 INTRODUCTION

Longview Power LLC 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." Longview Power operates Longview Unit 1, which is a coal fired electric generating unit (EGU), and specifically requested that Black & Veatch develop a high-level assessment report regarding four specific items:

- Variable frequency drive deployment for induced draft fans.
- Variable frequency drive deployment for boiler feed pumps.
- Potential internals upgrades for boiler feed pumps.
- Variable frequency deployment for forced draft fans (considered to be "targeted heat rate assessments" under ACE and a potential method for complying with CO_2 standards of performance).

To meet these goals, Black & Veatch prepared a high-level analysis of these heat rate improvement (HRI) projects that have been proposed by the EPA as the best system of emissions 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 baseline full-load efficiency parameters for Longview Unit 1, along with net plant heat rate (NPHR) and CO_2 emissions rates. These data were gathered from the Longview Unit 1 PI Data and performance calculations and adjusted based on standard equations for consistency. The actual performance data is from June 25, 2019, from 13:00 to 17:00.

Table 2-1 Longview Unit 1 Baseline Actual Full Load Data

Unit	Gross/ Net (MW)	Net Turbine Heat Rate (NTHR) (Btu/kWh), Actual	Boiler Efficiency, HHV Basis (%)	NPHR (Btu/kWh)	Coal Burn Rate (ton/h)	Coal HHV (Btu/lbm)	CO_2 Emissions (ton/h)
Longview Unit 1	781.9/ 706.2	6,955	89.90	8,566	236.5	12,789	601.6

Btu/kWh: British thermal unit per kilowatt hour.
Btu/lbm: British thermal unit per pound-mass.
HHV: higher heating value.
ton/h: tons per hour.

The unit consists of a Foster Wheeler supercritical pulverized coal boiler with single reheat stage. Six pulverizers supply the boiler with coal, and combustion air is supplied by two forced draft (FD) fans. Two Ljungström combustion air heaters are used to heat primary and secondary air. Nitrogen oxides (NOx) control systems installed at the unit include low-NOx burners and a selective catalytic reduction (SCR) system. Particulate control is by a pulse jet fabric filter (PJFF). Sulfur dioxide (SO_2) control is by a wet flue gas desulfurization (WFGD) system. The baseline coal quality was based upon the weighted average of coal deliveries from January 2019 through March 2020 from the Cumberland FOB point.

3.0 Description of Heat Rate Improvement Alternatives

This preliminary heat rate project screening was based on a high-level analysis of Longview Unit 1, as well as Black & Veatch's experience with similar projects. The projects depicted herein were selected from heat rate improvement (HRI) projects detailed by the EPA in its ACE proposal as BSER projects.

3.1 VARIABLE FREQUENCY DRIVE UPGRADES

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 equipment from some 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 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 steps are typically as follows:

- Replace the 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.
- Make upgrades to the lube oil system as necessary.
- Install new VFD enclosure foundations.
- Install 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. The air-cooled VFD equipment can further reduce equipment installation and maintenance costs.

The logistics of these types of upgrades are typically as follows:

- Engineering design and specification development: 2 months.
- Bid process: 1.5 months.
- Contract negotiations: 1.5 months.
- Drawing submittal and reviews: 2 months.
- Lead time for equipment: 6 to 12 months.
- Outage time: approximately 1 month.

The rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps and the large draft fans for handling combustion air and flue gas (forced draft and induced draft fans).

3.1.1 Boiler Feed Pumps

Based on available information, Longview boiler feed pumps (BFP) auxiliary power consumption benefit is estimated to be negligible at full load (782 MW gross) and 3.8 MW at low load (475 MW gross).

Refer to Figures 3-1 and 3-2, which illustrate the current BFP train operation and future variable speed operation with the addition of VFDs. The VFD analysis allowed a reduction of pump speeds by 4 percent at full load and 29 percent at low load. These pumps operate near their highest efficiency point at full load, thus there is only savings potential at low load, even with the fluid drives still in place. Given the high capacity factor of the unit, the practical annual potential heat rate improvement is low (0.19 percent), especially given the high cost of the VFDs.

The estimated furnish and erect price for a VFD system for the Longview BFPs includes VFD, VFD enclosure, enclosure foundations, coupling, new power cabling and any new raceway required, engineering, installation, and contingency. Limited available space immediately around the rotating equipment would not affect the installation of VFD systems as the equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the VFD.

VFD Deployment for BFPs

Total Installed Capital Cost:	$9.9 million for three pumps
Auxiliary Power Reduction:	Full load (782 MW gross): Negligible
	Low load (475 MW gross): 3.9 MW
Heat Rate (Efficiency) Improvement:	Full Load (782 MW gross): Negligible
	Low Load (475 MW gross): 0.5 percent
Estimated Additional Annual O&M Cost:	$9,000 for three pumps

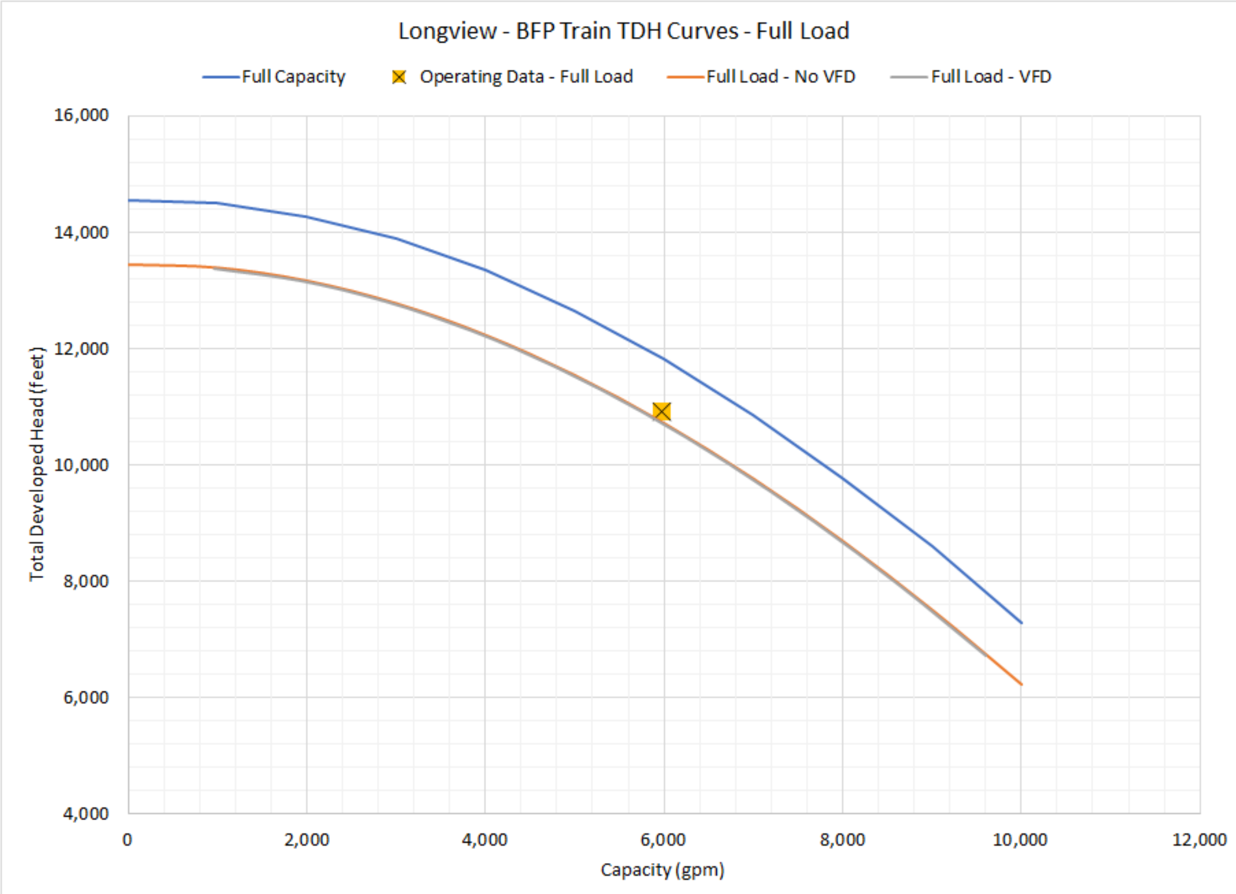

Figure 3-1 Boiler Feed Pump Train Curves - Full Load Variable Frequency Speed Comparison

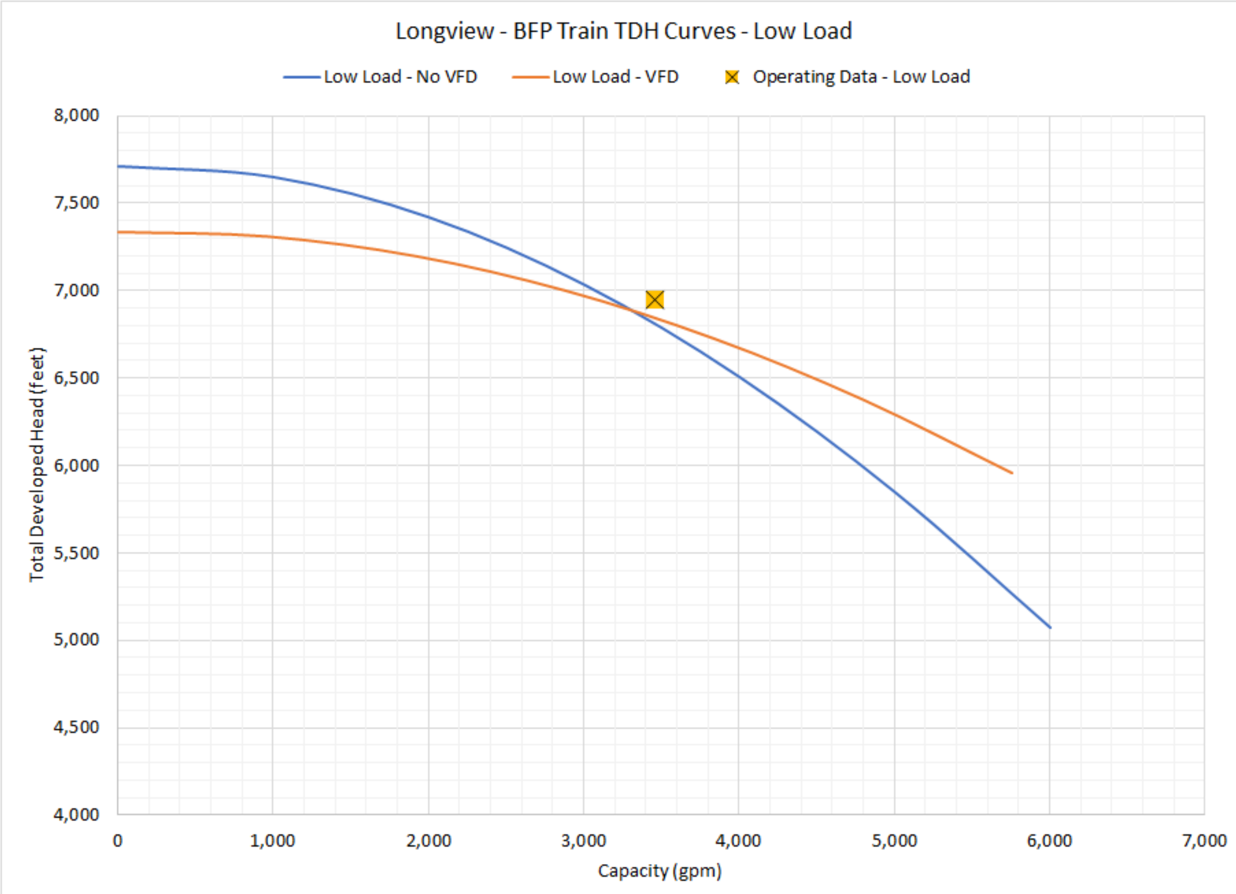

Figure 3-2 Boiler Feed Pump Train Curves - Low Load Variable Speed Comparison

Note as well that no analysis was conducted on the potential for utilizing the booster pump in any auxiliary manner to improve BFP utilization, as that was outside the scope of this study.

Overall, the estimated benefit from implementing VFD drives on the boiler feed pumps, compared to the estimated cost, indicates that from the standpoint of implementing the BSER for Longview this option does not have statistically significant merit. Therefore, this option is not recommended for compliance.

3.1.2 Large Draft Fans

Longview Unit 1 has forced and induced draft air fans that will be evaluated in this study. The forced draft and induced draft fans are currently axial-type with single speed motors and controlled by modulating blade position (variable blade pitch controls).

3.1.2.1 Forced Draft Fans

According to the available information and operating data the Longview Unit 1 forced draft (FD) fan, auxiliary power consumption would be estimated to decrease by 410 kW for two fans at full load (782 MW gross) and 220kW at low load (475 MW Gross). Refer to Figure 3-3 and Figure 3-

4 illustrating the current FD fan operation with variable blade pitch controls and future variable speed operation with VFDs.

Axial fans with blade modulation operate at a very efficient load profile, reducing the benefits associated with VFD operation. Additionally, following installation, the VFD may not operate at the most efficient speed to avoid the stall line of the axial fan. Also, control of the fan following VFD installation will be complicated by the both the speed control and blade angle control.

The evaluated impacts of this project are as follows:

VFD Deployment for FD Fans

Total Installed Capital Cost:	$2,472,000 for two fans
Auxiliary Power Reduction:	Full load (782 MW gross): 0.41 MW
	Low load (475 MW gross): 0.22 MW
Heat Rate (Efficiency) Improvement:	Full load (782 MW gross): 0.058 percent
	Low load (475 MW gross): 0.052 percent
Estimated Additional Annual O&M Cost:	$6,000 per unit

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

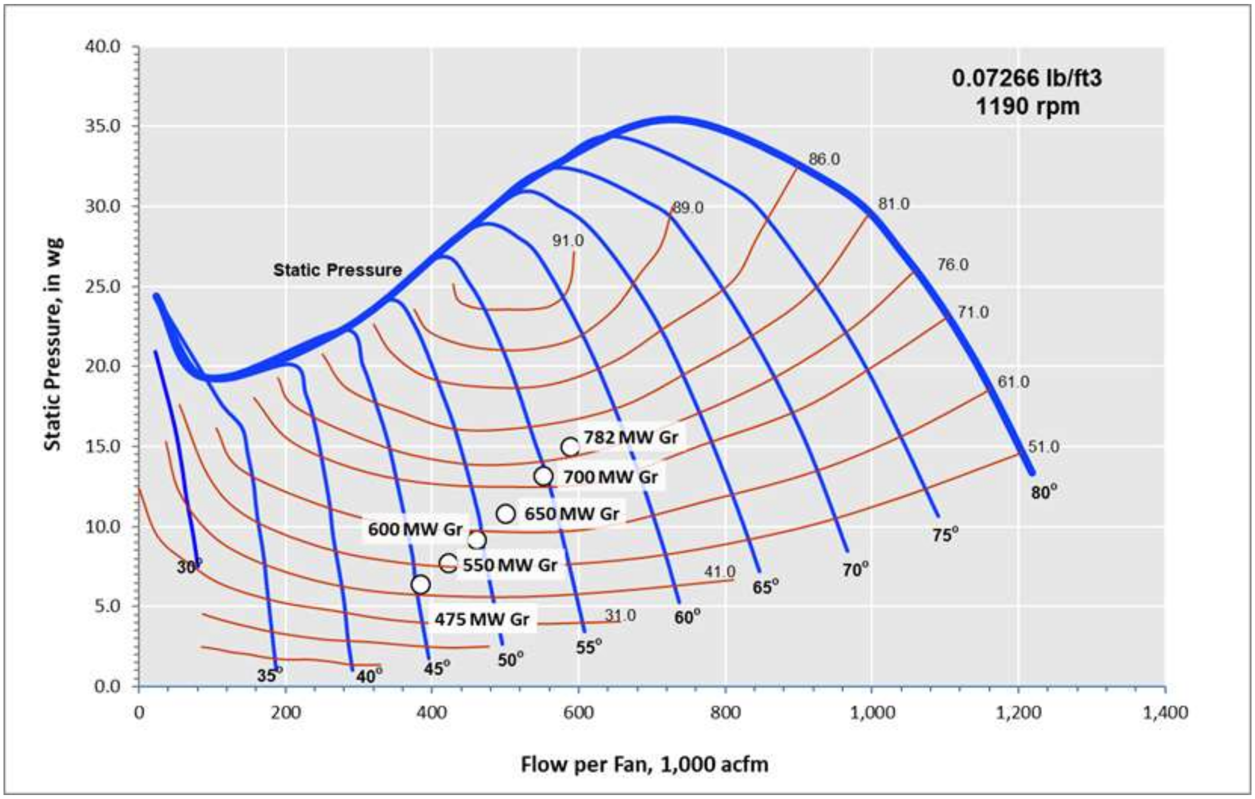

Figure 3-3 Longview Unit 1 FD Fan Operation – Variable Blade Pitch Control

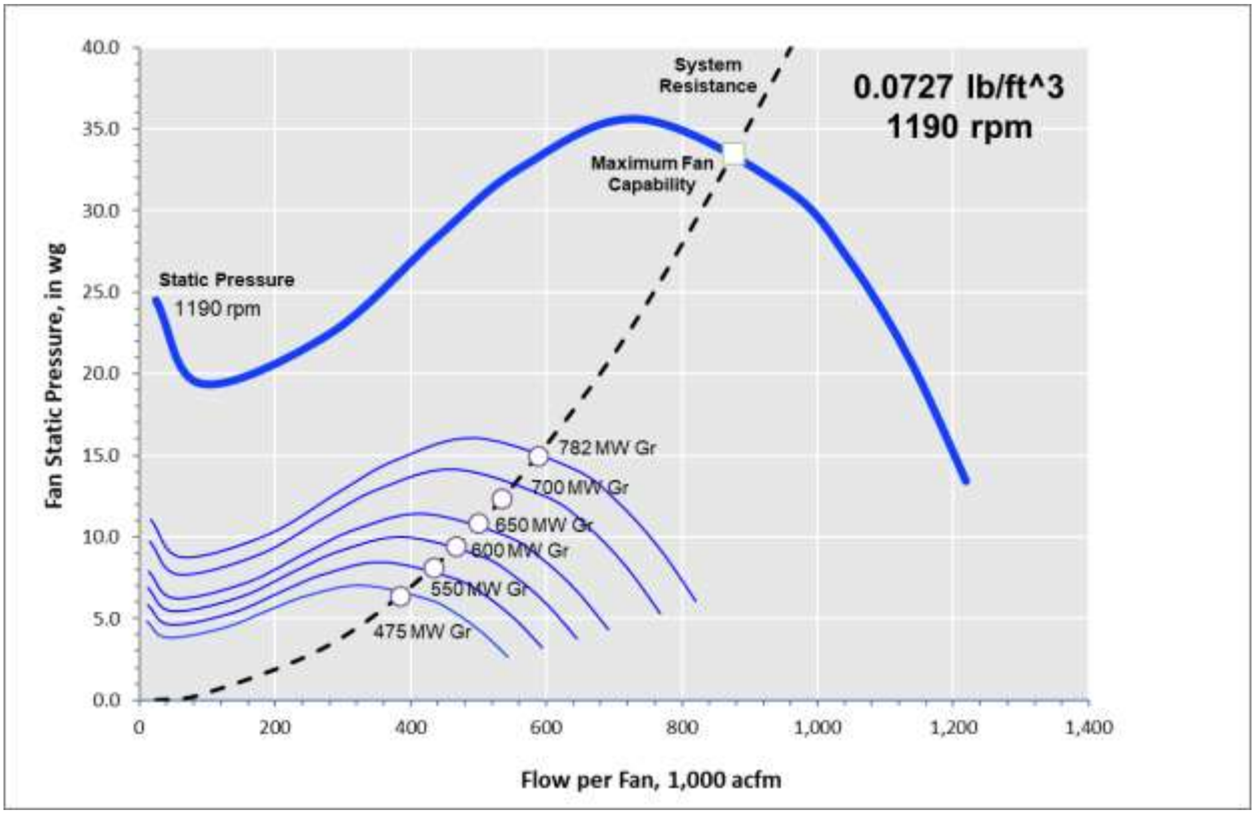

Figure 3-4 Longview Unit 1 FD Fan Operation – Variable Speed with VFDs

Overall, the estimated benefit from implementing VFD drives on the forced draft fans, especially when compared to the estimated cost, indicates that from the standpoint of implementing the BSER for Longview this option does not have statistically significant merit. Therefore, this option is not recommended for compliance.

3.1.2.2 Induced Draft Fans

According to the available information and operating data, the Longview Unit 1 induced draft (ID) fan auxiliary power consumption benefit is estimated to be negligible for two fans at full load (782 MW gross) and 120 kW at low load (475 MW gross). Refer to Figure 3-5 and Figure 3-6 illustrating the current ID fan operation with variable blade pitch control and future variable speed operation with VFDs.

Axial fans with blade modulation operate at a very efficient load profile, reducing the benefits associated with VFD operation. In this case of this application, the VFD may result in less efficient operation if used to reduce speed at full load. Following installation, the VFD may not operate at the most efficient speed to avoid the stall line of the axial fan. Also, control of the fan following VFD installation will be complicated by the both the speed control and blade angle control.

The evaluated impacts of this project are as follows:

VFD Deployment for ID Fans

Total Installed Capital Cost:	$3,650,000 for two fans
Auxiliary Power Reduction:	Full load (782 MW gross): Negligible
	Low load (475 MW gross): 0.12 MW
Heat Rate (Efficiency) Improvement:	Full load (782 MW gross): Negligible
	Low load (475 MW gross): 0.028 percent
Estimated Additional Annual O&M Cost:	$6,000 per unit

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

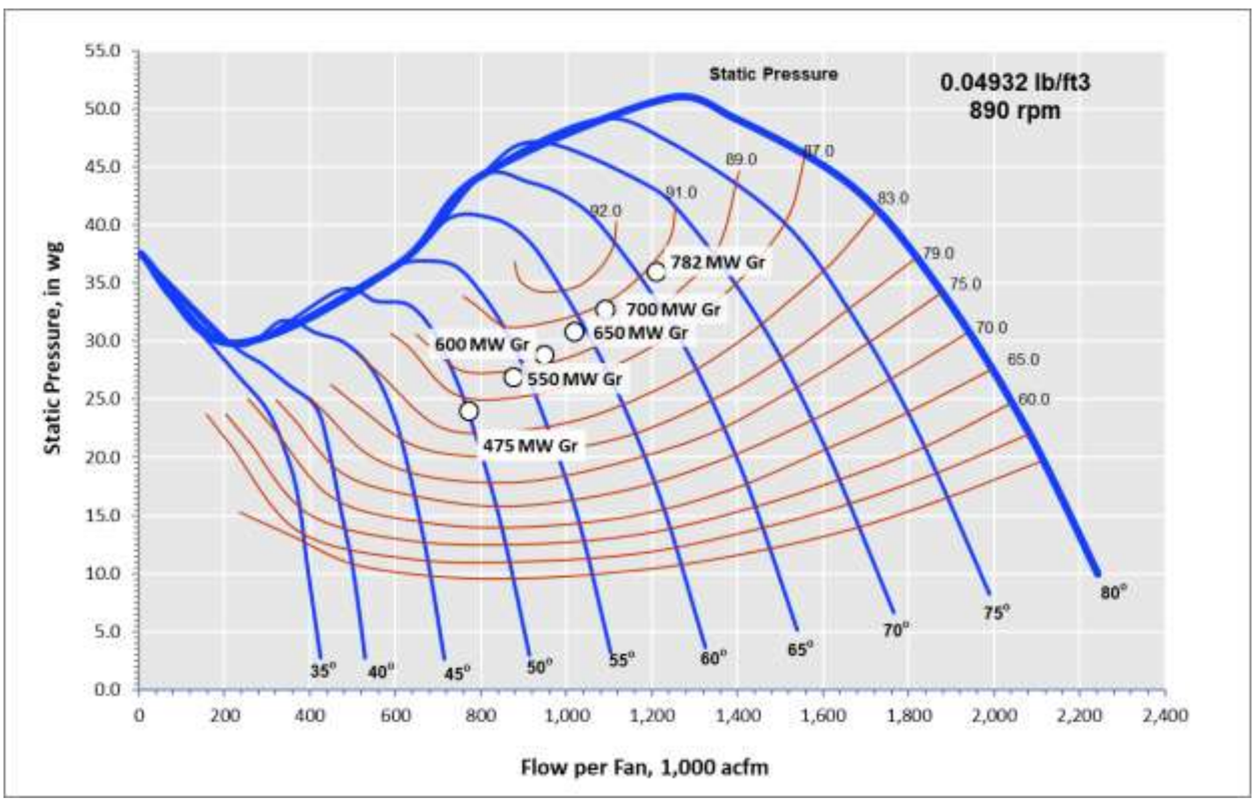

Figure 3-5 Longview Unit 1 ID Fan Operation – Variable Blade Pitch Control

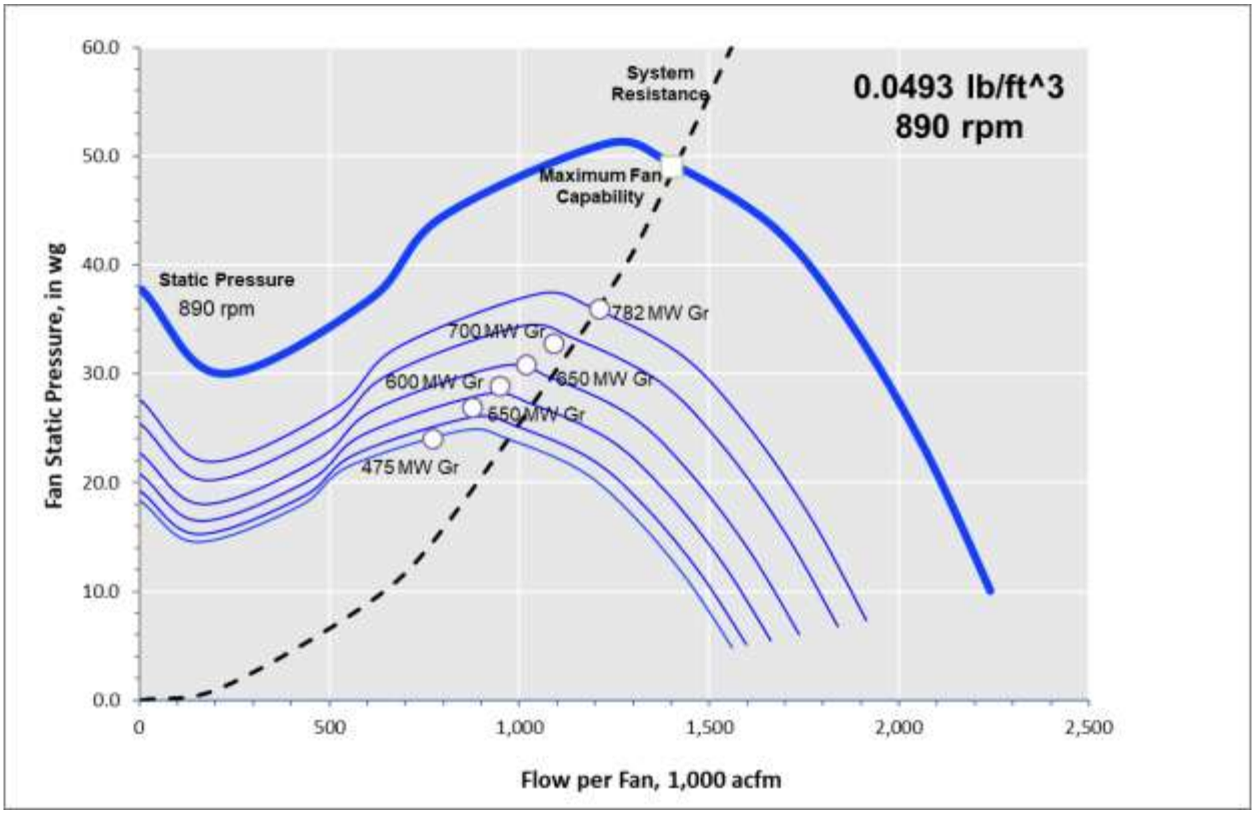

Figure 3-6 Longview Unit 1 ID Fan Operation – Variable Speed with VFDs

Overall, the estimated very limited benefit from implementing VFD drives on the induced draft fans, especially when compared to the estimated cost, shows that from the standpoint of implementing the BSER for Longview this option does not have statistically significant merit. Therefore, this option is not recommended as a method for compliance.

3.2 BOILER FEED PUMP UPGRADES, REBUILDING, OR REPLACEMENT

The purpose of this project would be to report on the current design of the boiler feed pumps (BFPs) and potential technology upgrades that could improve the heat rate (other than routine maintenance activities).

3.2.1 Boiler Feed Pumps

The plant has three 50 percent boiler feed pumps trains, each comprised of a single speed booster pump and motor, a VOITH hydraulic geared coupling, and a main boiler feed pump. The booster pumps are KSB model KRHA 300/660. The main boiler feed pumps are KSB model CHTD 7/7 (seven stage), horizontal, barrel-type pumps with radial impellers and single-entry. Each pump has a rated capacity of 6,550 gallons per minute (gpm), operating pressure of 4,520 pounds per square inch gauge (psig), operating temperature of 372 °F, total developed head (TDH) of 11,346 psig, and developed pressure of 4,345 psi at 5,072 revolutions per minute (rpm).

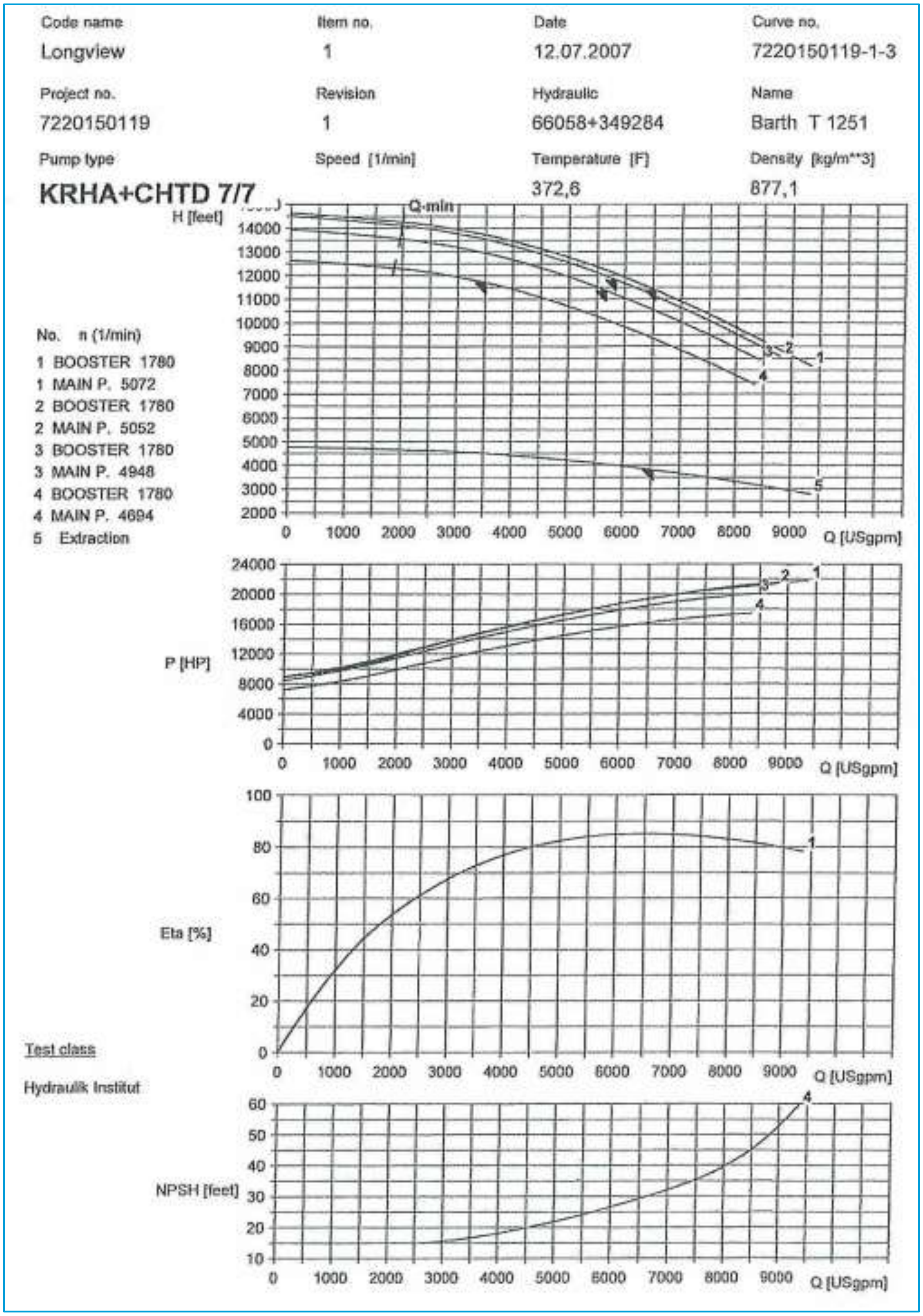

Figure 3-7 Boiler Feed Pump Performance Curves

SIEMENS	Document No.:	USA741-XW01-LAC-4601-01
	Project:	**Longview**
Specification for Boiler Feedwater Pumps	Index / Date:	01 / June 25, 2007
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APPENDIX B1
PUMP DESIGN DATA SHEET

Operating, system and Guarantee Data			***VWO***	***Bypass***	***ASME Master Stamping***	***ASME SV Open***		***Inter-stage***
Designation		**Units**						
System Data	Number installed	[-]	3					
	Number in operation	[-]	2					
	Plant Load Service	[%]	50%					
	Medium	[-]	Feedwater					
	pH-value Medium at 23 °C	[-]						
	Solid Content / Water Quality	[mg/m³]						
	Max.Allow. Working Pressure (MAWP) suction side	[psig]	262					
	MAWP discharge side	[psig]	5925					
	Pressure Nominal DIN / ANSI-Class							
	Test Pressure (Gauge)	[psig]						
	Temperature for pressure test	[°F]	room temperature (min. 20 [°C])					
	Max. Allow. Working Temp.	[°F]	410					
	Max. allowable shutoff head *)	[ft]	14,749.8					
	Max. allowable min flow	[gpm]						
	Max. flow	[gpm]						
	*) inclusive all fabrication tolerances							
Operating Data:	Operating Temperature	[°F]	370.5	372.6	372.7	372.7		370.5
	Density	[lbm/ft³]	56.0	55.9	56.0	56.0		56.0
	NPSH available (refered to pump suction nozzle)	[ft]	50.6	49.9	50.4	52.3		50.6
Operating Pressure (abs)	Inlet	[psia]	175.0	175.0	176.0	177.0		175.0
	Intermediate Stage	[psia]						1480.0
	Main Stage	[psia]	4510.0	4520.0	4554.0	4638.0		4510.0
Flow Rate	Inlet	[gpm]	6,367	6,550	6,367	3,826		6,367
	Intermediate Stage	[gpm]	693		523	309		693
	Main Stage	[gpm]	5,674	6,550	5,844	3,517		5,674
Developed Head and Pressure	Intermediate Stage	[ft]						3,415.0
	Intermediate Stage	[psid]						1,305
	Main Stage	[ft]	11,327	11,346	11,777	11,673		11,327
	Main Stage	[psid]	4,335	4,345	4,509	4,461		4,355

Siemens AG · Power Generation (PG)

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This document is subject to the handling restrictions set forth on the title page.

Figure 3-8 Boiler Feed Pump Design Data Sheet

The full load operating set from July 25, 2019 has the Boiler Feed Pump 1 operating at 4,860 rpm with a discharge flow rate of 5,970 gpm and TDH of 10,912 feet. With a pump speed of 4,860 rpm and the full load operating flow rate the design curve indicates a TDH of 10,739 feet. The pump lies slightly above its curve, suggesting that this pump is in good operation condition and no significant degradation has occurred. As a result, technology upgrades to the boiler feed pump internals are not recommended as a viable method for heat rate improvement. It is only recommended that that the regular program of maintenance and as-needed repair continue.

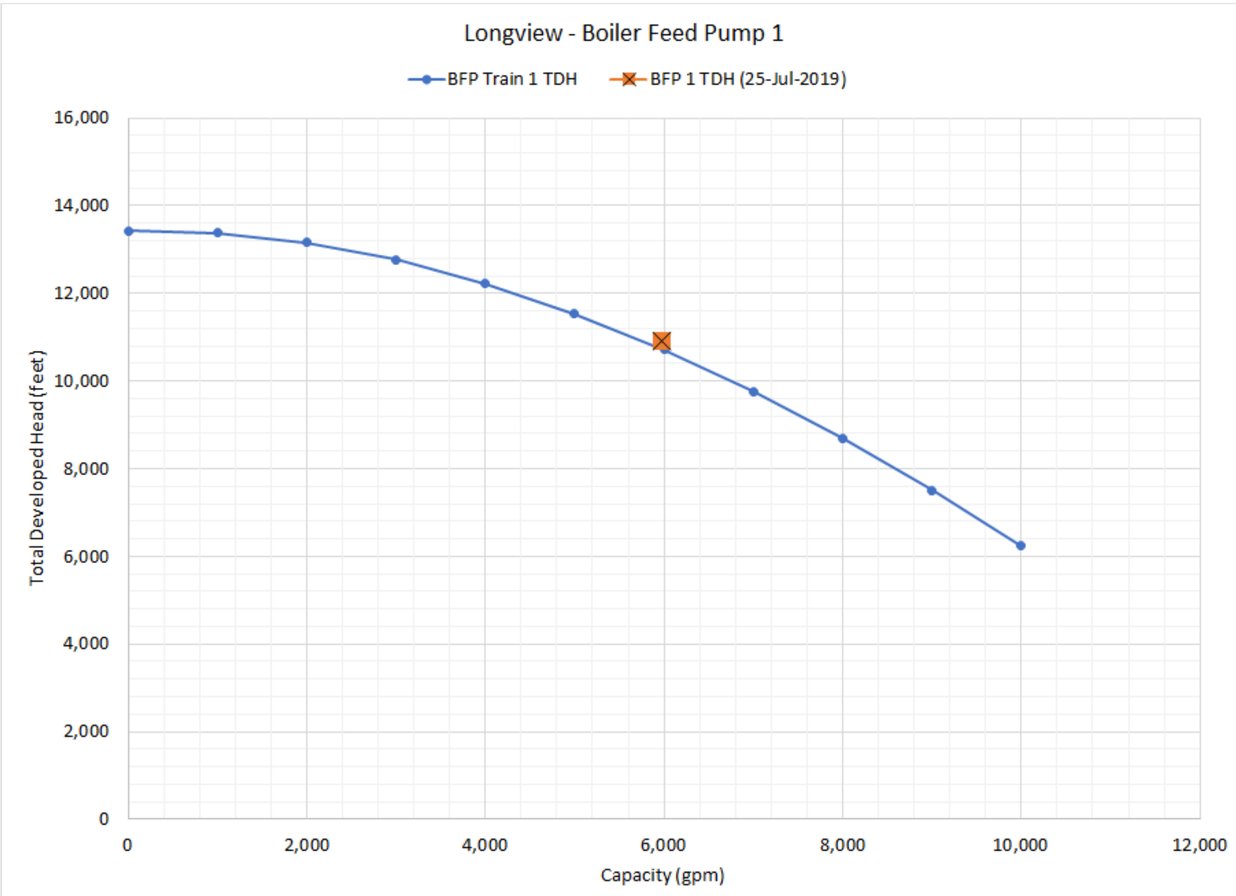

Figure 3-9 Boiler Feed Pump 1 Performance

The full load operating set from August 16, 2019 has the Boiler Feed Pump 2 operating at 4,866 rpm with a discharge flow rate of 5,924 gpm and TDH of 10,961 feet. With a pump speed of 4,866 rpm and the full load operating flow rate the design curve indicates a TDH of 10,806 feet. The pump lies slightly above its curve, suggesting that this pump is in good operation condition and no significant degradation has occurred. As a result, technology upgrades to the boiler feed pump internals are not recommended as a viable method for heat rate improvement. It is only recommended that that the regular program of maintenance and as-needed repair continue.

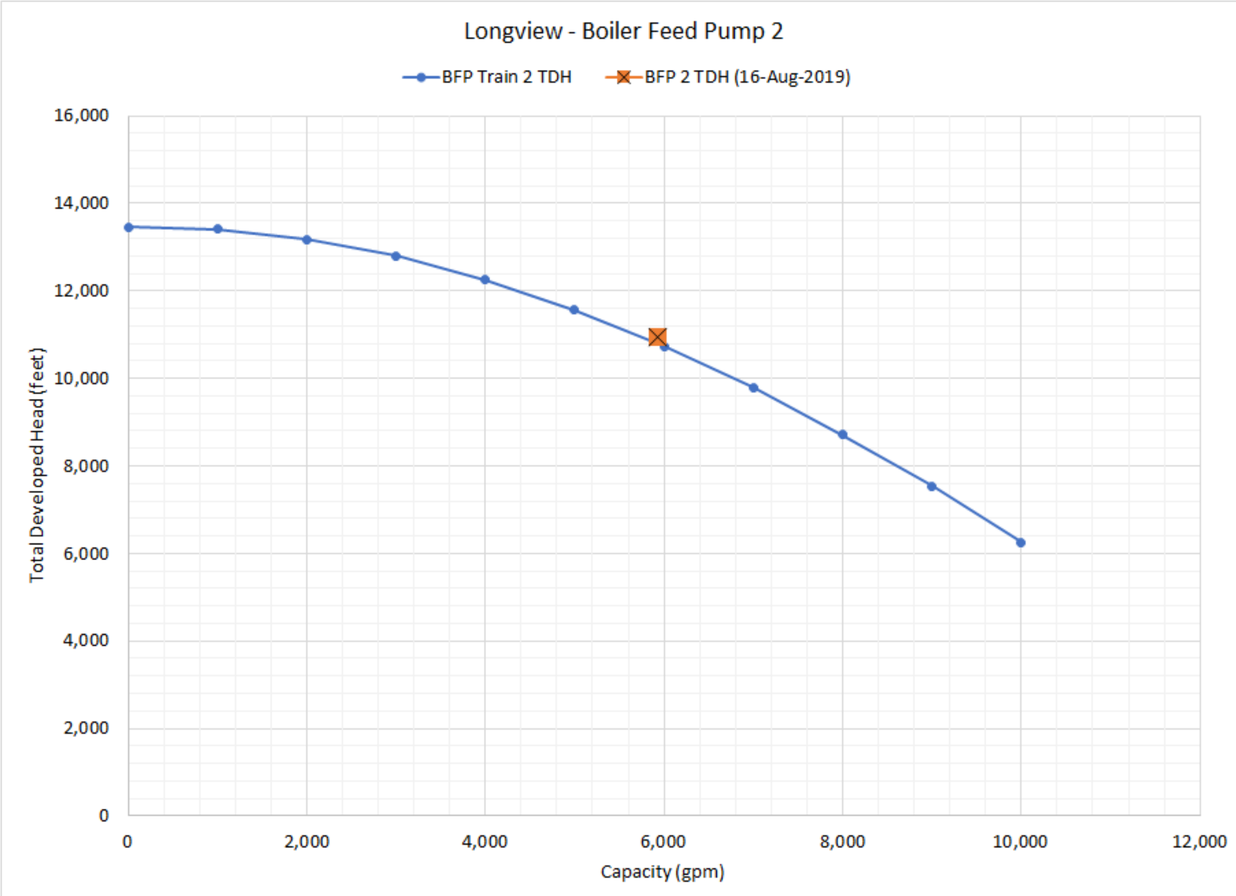

Figure 3-10 Boiler Feed Pump 2 Performance

The full load operating set from July 25, 2019 has the Boiler Feed Pump 3 operating at 4,838 rpm with a discharge flow rate of 5,989 gpm and TDH of 10,843 feet. With a pump speed of 4,838 rpm and the full load operating flow rate the design curve indicates a TDH of 10,606 feet. The pump lies slightly above its curve, suggesting that this pump is in good operation condition and no significant degradation has occurred. As a result, technology upgrades to the boiler feed pump internals are not recommended as a viable method for heat rate improvement. It is only recommended that that the regular program of maintenance and as-needed repair continue.

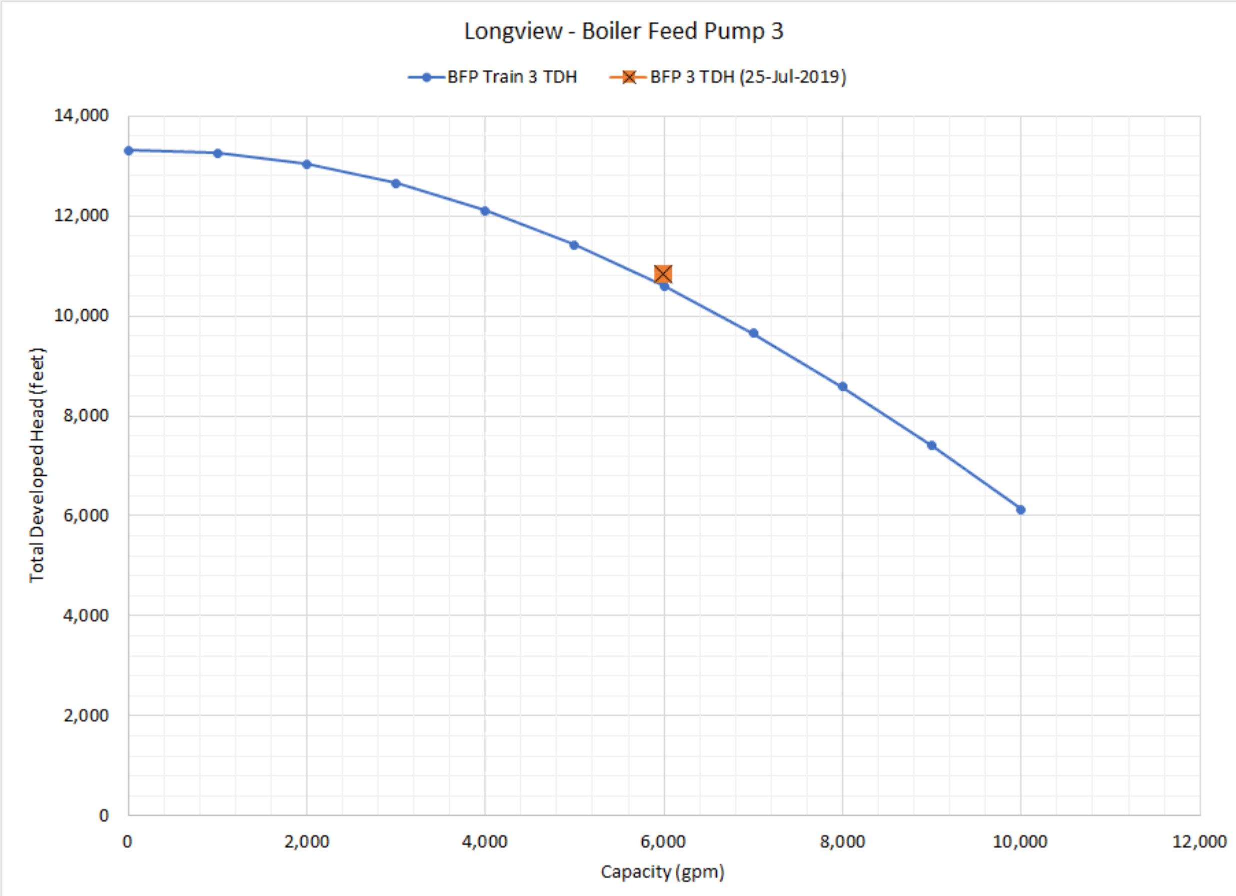

Figure 3-11 Boiler Feed Pump 3 Performance

3.3 IMPROVED OPERATIONS AND MAINTENANCE PRACTICES

The purpose of this project would be to improve O&M practices as they pertain to the following two areas of focus: HRI training, and on-site appraisals for identifying additional HRIs. This section is provided as a generic reference to show potential based upon Black & Veatch experience, and is not intended to apply specifically to Longview.

3.3.1 Heat Rate Improvement Training

Black & Veatch conducts heat rate awareness training, which covers the fundamentals of determining unit performance, how to use these metrics, and the operating conditions and decisions that impact unit efficiency and heat rate. The course includes numerous real-life case studies identified through years of monitoring and diagnostic work. This on-site course is typically 2.5 days and is primarily geared toward operators and engineers.

Total Installed Capital Cost:	$15,000/class (could cover multiple units and plants).

Heat Rate (Efficiency) Improvement:	Unknown, although improved O&M practices at peer coal fired EGUs have claimed to result in NPHR improvements of 0.1 to 0.5 percent in the first year of implementation.

3.3.2 On-Site Heat Rate Appraisals

This item, which is mentioned as a BSER in the EPA ACE proposal, is left open to interpretation and 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 HRI 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 and drain cooler approach 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), 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 caused by debris in the heater.
- An analysis of 19 different truck coals supplied to a power plant found that not only were seven of the coals unprofitable to burn, burning the worst coal resulted in a

heat rate loss of more than 2 percent. Moreover, this coal was responsible in whole or in part for most of the plant de-rates caused by high-temperature sodium-based fouling, which cost the unit an additional 1.2 percent in heat rate on an annual basis because of the increased number of starts and stops from fouling-related outages.

- A long-term analysis of plant continuous emissions monitoring system data and motor amperage data found that a malfunctioning VFD controller in the coal handling system was responsible for incorrect blending 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 evermoving 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 HRI.

3.4 GROSS VERSUS NET HEAT RATE IMPROVEMENT

The NPHR can be determined by the input/output method, whereby the equation is as follows:

$$NPHR = \frac{Total\ Fuel\ Heat\ Input, Btu/h}{Net\ Generation, kW}$$

The resulting calculation is whence is derived the mixed US/SI units of Btu/kW*h. Correspondingly, the gross plant heat rate (GPHR) is as follows:

$$GPHR = \frac{Total\ Fuel\ Heat\ Input, Btu/h}{Gross\ Generation, kW}$$

While technically correct, this simple form of plant heat rate equations hides the fact that the NPHR is actually the product of the efficiencies of the following three primary energy conversion processes within a Rankine-cycle power plant:

- Boiler efficiency, which is where fuel energy is converted to steam energy.
- Turbine efficiency, which is where steam energy is converted to rotational energy.
- Electrical use efficiency, which is how efficiently the plant utilizes the rotational energy to generate saleable electricity.

Thus, a better equation that illustrates these three energy conversion processes is known as the loss method equation:

$$NPHR = \frac{Net\ Turbine\ Heat\ Rate, \frac{Btu}{kW * h}}{Boiler\ Efficiency\ (fraction) * \frac{Net\ Generation, kW}{Gross\ Generation, kW}}$$

Correspondingly, since the concern for the GPHR is the gross generation, the GPHR heat loss equation is as follows:

$$GPHR = \frac{Net\ Turbine\ Heat\ Rate, \frac{Btu}{kW * h}}{Boiler\ Efficiency\ (fraction) * 1.0}$$

Therefore, the primary difference between the GPHR and NPHR is how one accounts for station service (auxiliary power). Take, for example, the case of a unit with the following characteristics:

- Gross output: 400 MW
- Net output: 370 MW
- NTHR: 8,000 Btu/kWh
- Boiler efficiency: 88 percent

By utilizing the previous equation for NPHR, the result for this unit would be as follows:

NPHR = 8,000 / ([88/100]*[370/400]) = 9,828 Btu/kWh

And the GPHR for this unit would be as follows:

GPHR = 8,000 / (88/100) = 9,090 Btu/kWh

If it is assumed that this unit deploys VFDs for its main fans and reduces the station service by 2 MW, the net generation will increase at the same gross output. Thus, the new characteristics of the unit are as follows:

NPHR = 8,000 / ([88/100]*[372/400]) = 9,775 Btu/kWh

GPHR = 8,000 / (88/100) = 9,090 Btu/kWh

In this case, the NPHR has shown an improvement of 53 Btu/kWh (about 0.5 percent), but the GPHR reflects no such benefit.

Because of its neglect of changes in station service, utilizing the GPHR measurement, therefore, has the risk of invalidating the following technologies:

- Air heater and duct leakage control.[1]
- VFD motor deployment.
- Many improved O&M practices.
- BFP upgrades for electric BFPs.

The case where the gross heat rate would be the better heat rate metric for a coal fired EGU would be where emissions controls for pollutants such as NO_X, SO_2, etc., must be installed or upgraded on a unit to meet more stringent emissions limits. Taking again our hypothetical unit, if the unit must install an SCR system that requires 5 MW of additional station service, the gross heat rate would not be impacted, but the net heat rate would worsen from its baseline value of 9,828 Btu/kWh to the following:

NPHR = 8,000 / ([88/100]*[365/400]) = 9,963 Btu/kWh

In other words, a 1.37 percent worsening of NPHR. This could be problematic in cases where a unit's performance standard was based on net measurement and an emissions control addition resulted in an increased net heat rate that was not contemplated or accounted for when the standard was set.

[1] Care must be taken to distinguish between air heater heat transfer surface upgrades, which will increase the boiler efficiency, and air heater leakage reduction, which will reduce the station service. In the first case, increasing the boiler efficiency improves both the NPHR and GPHR. In the second case, reducing the station service only improves the NPHR. The proposed rule is also not clear on whether leakage reduction projects are considered to

4.0 Performance and Carbon Dioxide Reduction Estimates

High level plant performance estimates were used to estimate 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 from the PI data provided by Longview and assumed a baseline 76.7 percent net capacity factor. The 76.7 percent net capacity factor was retrieved from the S&P Global database as the average value from 2015-2019, inclusive. In addition to PI data, the existing Electric Power Research Institute Vista model of Longview was utilized to confirm and predict the annual average net plant heat rate values across the load curves.

Table 4-1 Basis for Current CO_2 Reduction Estimates – 76.7 Percent Net Capacity Factor

Gross/Net Capacity (MW)	Net Capacity Factor (%)	Average Annual NPHR (Btu/kWh)*	Fuel Heat Input (MBtu/y)*	LBM CO_2/ MBtu (HHV)*	Annual CO_2 (tons/y)*
781.9/ 706.2	76.7	8,596	41,360,298	200.4	4,144,410
*Note that this differs from Table 2-1 because an annual average value is used, rather than full load value.					

The annual CO_2 reductions over the next 5 years shown in Table B-2 were projected using estimated values provided by Longview personnel. These values ranged from 85 to 92 percent, with Longview giving an average value of 87 percent. Gross and net capacity were unchanged, although the average annual NPHR did vary because of the difference in the net capacity factor.

Table 4-2 Basis for Future CO_2 Reduction Estimates – 87.0 Percent Net Capacity Factor

Gross/Net Capacity (MW)	Net Capacity Factor (%)	Average Annual NPHR (Btu/kWh)	Fuel Heat Input (MBtu/y)	LBM CO_2/ MBtu (HHV)	Annual CO_2 (tons/y)
781.9/ 706.2	87.0	8,577	46,491,199	200.4	4,658,560

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)

Appendix A. Abbreviations and Acronyms

°F	Degrees Fahrenheit
ACE	Affordable Clean Energy (Plan)
BSER	Best System of Emission Reduction
Btu	British Thermal Unit
CO	Carbon Monoxide
CO_2	Carbon Dioxide
EPA	United States Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
FD	Forced Draft
GPHR	Gross Plant Heat Rate
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
IP	Intermediate-Pressure
kW	Kilowatt
kWh	Kilowatt-hour
lbm	Pound-Mass
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
PI	Plant Instrumentation
rpm	Revolutions per Minute
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
TDH	Total Developed Head
ton/h	Tons per hour
VFD	Variable Frequency Drive

Vista	The EPRI Vista fuel quality impact analysis program, which is used to model this unit.
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 (Current Net Capacity Factor – 76.7 Percent)

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**
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	9,900	0.19	16.4	78,998	7,916	1,250.66	Low
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,472	0.06	4.8	23,041	2,309	1,070.70	Low
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	3,650	0.01	0.9	4,424	443	8,233.96	Low
Boiler Feed Pump Upgrades, Rebuilding, Or Replacement	Boiler Feed Pumps	NA	NA	NA	NA	NA	NA	NA

Table B-2 Preliminary EPC Capital Cost Estimate (in 2020 Dollars) and First Year Performance Benefits (Future Net Capacity Factor – 87.0 Percent)

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**
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	9,900	0.19	16.4	88,798	8,898	1,112.63	Low
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,472	0.06	4.8	25,899	2,595	952.53	Low
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	3,650	0.01	0.9	4,973	498	7,325.20	Low
Boiler Feed Pump Upgrades, Rebuilding, Or Replacement	Boiler Feed Pumps	NA	NA	NA	NA	NA	NA	NA