Appendix C
Standards of Performance Demonstration
[40 C.F.R. §§ 60.5740a(a), (a)(1), (a)(2), & (a)(4)]

[40 C.F.R. § 60.24a(e)]

In applying a standard of performance to a particular source, the State may take into consideration factors, such as the remaining useful life of such source, provided that the State demonstrates with respect to each such facility (or class of such facilities): (1) unreasonable cost of control resulting from plant age, location, or basic process design; (2) physical impossibility of installing necessary control equipment; or (3) other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

[40 C.F.R. §§ 60.5740a(a), (a)(1), and (a)(2)]

This information must be submitted to the U.S. EPA as part of your plan submittal but will not be codified as part of the federally enforceable plan upon approval by the U.S. EPA.

The state must include a summary of how it determined each standard of performance for each designated facility according to 40 C.F.R. § 60.5755a(a).

> The State must set a standard of performance for each designated facility within the state. The standard of performance must be an emission performance rate relating mass of CO_2 emitted per unit of energy (e.g. pounds of CO_2 emitted per MWh). In establishing the standard, the State must consider the applicability of the heat rate improvements (HRI) and associated degree of emission limitation achievable included in §60.5740a(a)(1) and (2) to the designated facility. The State must include a demonstration in the Plan for how it considered each HRI and associated degree of emission limitation achievable in calculated each standard of performance. A state may consider remaining useful life and other factors, as provided for in §60.24a(e) and must include a demonstration for how such factors were considered.

The State must include in the summary an evaluation of the applicability of each of the following heat rate improvements to each designated facility: (i) neural network/intelligent sootblowers; (ii) boiler feed pumps; (iii) air heater and duct leakage control; (iv) variable frequency drives; (v) blade path upgrades for steam turbines; (vi) redesign or replacement of economizer; and (vii) improved operating and maintenance practices.

As part of the summary regarding heat rate improvement (HRI) applicability to each designated facility, a State must include an evaluation of the degree of emission limitation achievable through application of the HRI according to Table 1 to Paragraph (a)(2)(i) of 40 C.F.R. § 60.5740a. If a State considers remaining useful life and other factors for a designated facility as provided in §60.24a(e) when applying a standard of performance, it must include a summary of the application of the relevant factors in deriving a standard of performance.

[40 C.F.R. § 60.5740a(a)(4)]

This information must be submitted to the U.S. EPA as part of your plan submittal but will not be codified as part of the federally enforceable plan upon approval by the U.S. EPA.

The State Plan demonstration must include, as applicable, a summary of each designated facility's anticipated future operation characteristics included in 40 C.F.R. § 60.5740a(a)(4)(i), a timeline for implementation, all wholesale electricity prices, a time period of analysis through 2035, and a demonstration that each standard of performance meets the requirements of 40 C.F.R. § 60.5755a.

West Virginia Plan Source Specific Demonstration

The justifications and demonstrations provided in this Appendix C in conjunction with the quantifiable, permanent, verifiable, and enforceable demonstration provided in Appendix D and the data and calculations provided in Appendix F satisfies the demonstration for Section 4.4.b of the State Plan, *Determination of each Standard of Performance*.

A. [60.5755a(a)] LONGVIEW POWER LLC STANDARDS OF PERFORMANCE

The standards of performance for Longview Power LLC (LVP) are defined in requirement 4.1.1 of Permit R13-3495. Compliance with the load bin standards is demonstrated in accordance with the CO_2 weighted average limit on a calendar year basis in accordance with the requirements and equations provided under conditions 4.4.4 and 4.4.5 of Permit R13-3495.

The load bin standards were developed for multiple operational load ranges beginning with the start-up / shutdown / minimum load operation identified as LB-0 through the baseload operating conditions identified as LB-5.

The load bin standards for LVP consists of an initial Level 1 emission rate for normal operations that was established for each of the load bins in requirement 4.1.1.a of Permit R13-3495. The initial Level 1 emission rate limit is established for normal operations. Also defined are load bin standards, identified as Level 2, for impaired operations if the conditions established in requirement 4.1.1.b of Permit R13-3495 are triggered and would only apply to load bins LB-1 through LB-5 and only approved for a specified duration of time. Impaired operation means the unit can operate below normal efficiency due to unavoidable equipment failure. If the Level 2 limit is triggered, it is calculated as the Level 1 limit multiplied by 1.10 (ten percent above the Level 1 limit) in accordance with the requirements established as condition 4.1.1.b of Permit R13-3495.

The established standards of performance for LVP are explained in detail in Section 4.4.b of the State Plan and are summarized in Table C-1 below for convenience in reviewing the justification and demonstrations provided in this Appendix C. The load bin standards include multiple components that apply to LVP starting with the initial compliance period and include provisions that should allow the standards to remain relevant over the life of the unit.

Permit condition 4.1.1.c of Permit R13-3495 provides for a unit degradation adjustment factor (UDAF) that is applied to the load bin standards annually following the initial compliance period. The standards are increased annually by 0.4% and once every five years are decreased 0.7% to reflect the recovery. Both adjustments are applied to the individual load bin CO_2 limits. The UDAF is applied up to and including calendar year 2046. Thereafter, the CO_2 load bin limits remain at the 2046 levels. Table 4.4.b-3 in the State Plan provides the load bin standards with the degradation and recovery rates calculated in accordance with condition 4.1.1.c of Permit R13-3495 through calendar year 2046.

Permit condition 4.1.1.d specifies the requirements and the conditions under which a coal adjustment factor (CAF) may be applied to the Level 1 and Level 2 CO_2 load bin standards in the event the source of coal changes in the future for LVP. The CAF is the ratio of future CO_2 emissions divided by the baseline CO_2 emissions as determined in accordance with Permit R13-3495 condition 4.3.1. The CAF is only applicable if LVP requires a fuel switch that results in a different source of coal that LVP has determined has an impact on the carbon dioxide emissions. Changes (variability) of measured coal properties from the same source of coal on a monthly basis does not constitute a CAF. The CAF, not to exceed 3.0% for each instance for which it is determined, increases or decreases the Level 1 and Level 2 CO_2 limits based on the calculated ratio as described above. If a CAF is applied, any subsequent required fuel switch that the permittee has determined has an impact on the carbon dioxide emissions (whether an increase or decrease) must follow the afore mentioned requirements and testing using the most recent previously adjusted CO_2 emissions and coal supply as the baseline to develop a new CAF ratio.

Compliance with the standards of performance is demonstrated based on a weighted average formula based on the operating time spent in each load bin during the compliance period, as established in conditions 4.4.4 and 4.4.5 of Permit R13-3495.

Appendix C is organized as follows:

- The rate based standard demonstration is in Section B.
- The demonstration concerning how the standards of performance were established is in Section C and includes discussions of the following elements:
    - Load bins
    - Gross vs. net
    - Baseline period
    - Level 1 normal operation limits
    - Level 2 impaired operation limits
    - Unit degradation adjustment factor
    - Coal adjustment factor
    - Weighted average limit
    - Stringency with 40 C.F.R. Part 60, Subpart TTTT
    - Compliance Period
- Demonstration of emission limitation achievable from HRI of BSER technologies in Section D
- Anticipated future operation characteristics discussion in Section E
- Demonstration the standards meet 40 C.F.R. § 60.5755a in Section F

Table C-1. Longview Power LLC Load Bin Standards.

Load Bin	Load Bin Range (MWHG)	Normal Operation Initial Level 1 Limit[1] (lbs CO_2/MWh)	Impaired Operation Level 2 Limit (lbs CO_2/MWh Net)
LB-0	< 313	9,864	n/a
LB-1	>313 - 407	2,230	2,453
LB-2	>407 - 501	2,108	2,319
LB-3	>501 - 595	2,050	2,255
LB-4	>595 - 689	2,002	2,202
LB-5	>689	1,958	2,154

1. Based on net generation for LB1 - LB5 and based on gross electricity generation for LB-0.

The discussion regarding the corresponding data and calculations supporting the development of the standards of performance is provided in Appendix F to the State Plan.

B. [60.5755a(a)(1)] RATE-BASED STANDARD

The standards of performance for LVP established in condition 4.1.1 of Permit R13-3495 are rate-based standards expressed as pounds of CO_2 per megawatt of net electricity generation in load bins LB-1 through LB-5. The start-up/shutdown/minimum load bin LB-0 is a rate-based standard expressed as pounds of CO_2 per megawatt of gross electricity generation.

The explanation for why net generation was chosen for load bins LB-1 through LB-5 and why gross generation was chosen for LB-0 is provided in Section C below.

C. [60.5755a(a)(2)] ESTABLISHING THE STANDARD OF PERFORMANCE

West Virginia performed the two-step process identified in the preamble of the federal ACE Rule concurrently in establishing the standard of performance for the SB1 unit at LVP. Step one establishes the standard of performance to reflect the degree of emission limitation achievable through application of the BSER. Step two considers the remaining useful life and other source-specific factors. West Virginia chose this approach for LVP because this facility is less than ten years old and the majority of the BSER technologies are considered best available technology (BAT) and were included in the base design of the unit or were implemented at LVP prior to the baseline period. In some cases, the BAT applied to the SB1 unit at LVP is considered superior to the BSER candidate technologies, and these source-specific factors were taken into consideration and are discussed in Section D of this Appendix C. The U.S. EPA stated in the preamble of the ACE rule "[t]he BSER is a list of candidate technologies that are HRI measures, which states will evaluate and apply to existing sources, establishing a standard of performance that is appropriately tailored to each existing source."[1]

Each candidate technology identified as BSER was analyzed and considered along with source-specific factors when establishing the standard of performance, this demonstration is provided in Section D of this Appendix C.

[1] 84 Fed. Reg. 32550 (July 8, 2019).

The standards of performance for LVP are explained in detail in Section 4.4.b of the State Plan and the load bin standards are summarized in Table C-1 in Section A above for convenience in reviewing the justification and demonstrations provided in this Appendix C. This Section C of Appendix C provides the justification for how the standards of performance were developed including discussions regarding the load bin approach, why net load or gross load was chosen for the rate based standard, the baseline period chosen for the analysis, and each of the factors included in the standards of performance. The corresponding data and calculations are provided in Appendix F of the State Plan.

Load Bin Discussion

Under the ACE emission guidelines, the standards of performance must apply at all times, including times of startup, shutdown, operating at less than minimum load, transitioning to base load, and operating at maximum load conditions. The decision on what load a specific EGU operates and for how long is not made by the EGU but is made by the regional transmission organization (RTO) electric grid operator, PJM in the case of LVP. The PJM market is very competitive and routinely varies demand from its supply sources. Although LVP currently operates as a base load unit and expects to continue operating as a base load unit into the future, it is conceivable that at some point during its life cycle it may shift to a load following mode of operation. The RTO dictates the loading of units based on actual supply and demand of the electric grid throughout each day.

In the preamble to the federal ACE rule, the U.S. EPA acknowledges the role of changing operating conditions on emissions performance and states the following:

> [S]tandards of performance should reflect variability in emission performance at an individual designated facility due to changes in operating conditions. Specifically, the agency believes it would be appropriate for states to identify key factors that influence unit-level emission performance (e.g., load, maintenance schedules, and weather) and to establish emission standards that vary in accordance with those factors. In other words, states could establish standards of performance for an individual EGU that vary (i.e., differ) as factors underlying emission performance vary. For example, states could identify load segments (ranges of EGU load operation) that reflect consistent emission performance within the segment and varying emission performance between segments. States could then establish standards of performance for an EGU that differ by load segment.[2]

West Virginia identified key factors that influence carbon dioxide emissions and heat rate performance at LVP and established the standards of performance to reflect those factors.

When West Virginia started analyzing the emissions and operational data supplied by LVP, it noticed the variability between start-up operations emissions and emissions from the unit at its typical base load operation. LVP currently operates approximately 90 percent of the time as a baseload unit. West Virginia wanted to ensure that the standard of performance developed for LVP would adequately represent operations at any operating load profile (base load, load following, peaking) and provide LVP the flexibility should the load profile change in the future without the need to modify the standard.

[2] 84. Fed. Reg. 32552 (July 8, 2019).

The SB1 unit has been operational less than ten years and is currently operating as a baseload unit which allows the unit to operate at its optimum heat rate (most efficient). Although the anticipated future operating characteristics, discussed in Section E of this Appendix C, indicate the unit will continue to operate as a baseload unit through 2035, there has been a significant amount of change to the electrical grid in the past ten years with the emergence of new natural gas units and renewable generation coming online. The regional transmission organization (RTO) that this unit provides electricity for is very competitive market. At some point, this unit's operating mode may shift from base load to load following. The RTO dictates the loading of the unit based on actual supply and demands of the RTO's electric grid on an hourly and daily basis. Thus, the unit may or may not be operating at its optimum load to achieve it optimum unit heat rate. As generating costs change in the future, so too will operating load characteristics. Establishing standards of performance for distinct load bins of operation, ensures the standard will continue to be representative of future operations and takes into consideration variability at different loads.

Another reason the load bin approach was selected for LVP is to adequately characterize emissions during SUSD conditions with a rate-based emission limit. For reasons discussed below, net load was preferable to gross load in establishing the CO_2 emission rate limit; however, this presented complications establishing the limit during SUSD conditions when there is zero electricity being sold to the electric grid. It is not possible to develop a rate-based standard due to the need to divide by zero. Developing a standard of performance based on a load bin concept enables the SUSD emissions to be included in the standard and be accounted for uniquely.

Structuring the standards of performance using load bins provides flexibility over the anticipated life of the unit should the unit transition from baseload operation to load following operation in the future. The load bin approach allows the CO_2 standard of performance to account for heat rate efficiency changes of the unit resulting from operating in different load bins.

The data for the baseline period was divided into six bins which consists of one bin for SUSD at times when the load is at or below minimum stable load conditions, and five bins for normal operation. The SUSD bin is referred to as Load Bin 0 (LB-0) and is defined from the time the LVP SB1 unit begins operating up to and including the minimum stable load, which is 40% of the maximum load (313 MWh gross). The maximum gross load of this unit is 787 MWh. The normal operating bins were determined by taking the difference between the minimum load and the maximum and dividing into five equal blocks. The ranges of these bins are presented in Table C-2 below.

Table C-2. Load Bin Key.

Load Bin	Range (MWh Gross)
LB-0	0-313
LB-1	>313-407
LB-2	>407-501
LB-3	>501-595
LB-4	>595-689
LB-5	>689

The operating hours for each of these load bins were then evaluated to ensure there was an adequate number of data points in each of these bins to develop a standard.

Gross Load versus Net Load Emissions Rate Discussion

Gross electric generation is the total amount of electricity generated from a unit. Net electric generation is the difference between the gross energy output minus the parasitic load (energy consumed by the unit to operate) of the unit. The parasitic load includes energy used to drive the pumps, fans, coal pulverizers, etc., that is required to operate the unit. The net electric generation is the actual amount of electricity sent to the electricity grid. For LVP, the net load is approximately 90% of the gross load.

Net electric generation was chosen to establish the standard of performance in load bins LB-1 through LB-5 because it allows the unit operator to focus on the load consumed by the auxiliary equipment and it provides consistency for LVP when analyzing the net plant heat rate (NPHR). "[T]he 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."[3]

It was necessary to establish the standard for LB-0 in terms of gross electricity generation because during SUSD, the unit is either coming up to minimum stable load for generation either from a cold start or from an idle position or in the process of shutting the unit down. During start-up conditions, the unit is burning fuel and emitting CO_2; however, the boiler is not yet up to temperature and not creating steam flow through the turbines. The start-up phase of the operation is prior to the unit stabilizing at their minimum operating load of 40%. Until the SB1 unit can sell electricity to the grid, there is zero net electricity generated.

The gross load emissions rate was selected for load bin LB-0 because during SUSD and when the unit is below the minimum stable operation load of 40%, there is either zero or minimal electricity being sold to the electric grid. Division by zero is infinite in mathematical terms and is identified as an error in spreadsheets. Under the ACE emission guidelines, work practice standards are not allowed as an option during SUSD and the standard of performance is required to be quantified during all times, including SUSD. To quantify the standard of performance during SUSD, the rate-based standard must be in terms of gross load when using a load bin approach. The gross electricity generated is small in comparison to generation during other loads of operation and for this reason, the standard of performance developed for this load bin is considerably higher because mathematically when dividing any number by a very small number, the result is a larger number.

Baseline Discussion

Determining the appropriate baseline period was one of the initial decisions that West Virginia made in establishing the standard of performance. The baseline period chosen for the SB1 unit at LVP is calendar year 2016 through the second quarter of 2020 for load bins LB-1 through LB-5. The West Virginia DEP considers this baseline period representative of the operation because all HRIs were implemented or the

[3] Section 3.4 of the Final "Longview Unit 1 Heat Rate Study" prepared for Longview Power by Black & Veach, August 11, 2020. *See Appendix J to the State Plan.*

technology installed prior to 2016. This baseline period is considered representative of anticipated future operation.

Operating time in LB-0 for the SB1 unit accounts for less than 1% of the total operating hours in the 2016 – 2020 Q2 sample data set. For this reason, data including 2012 to 2Q 2020 was used to develop the standard of performance for LB-0. The different baseline period for LB-0 is acceptable because the BSER HRI candidate technologies are not aimed at improving start-up and temporary low-load conditions.

By using this larger data set more data points are available for an increased confidence level as evidenced in the cumulative distribution plots below. As shown in the cumulative distribution plots below (Figures C-1 and C-2), data points with electrical generation have an extreme degree of variability due to the transitional nature of this load bin.

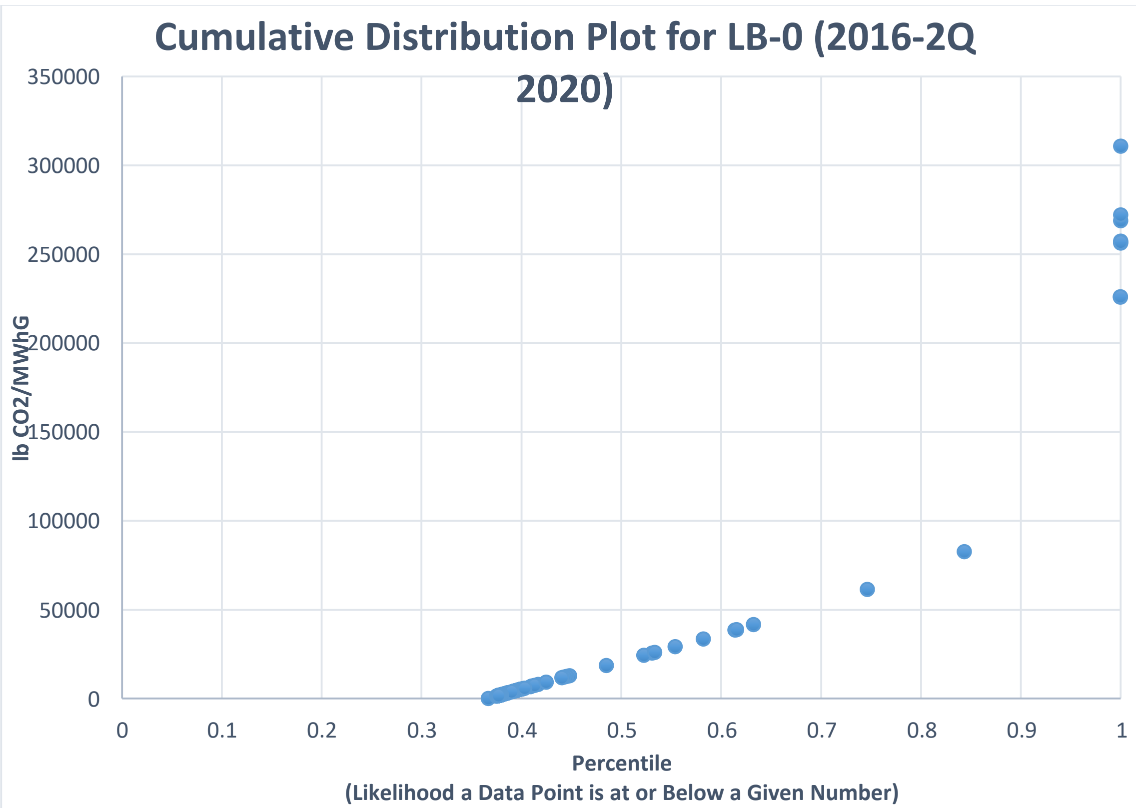

Figure C-1. Cumulative Distribution Plot for LB-0 (2016 – 2Q 2020).

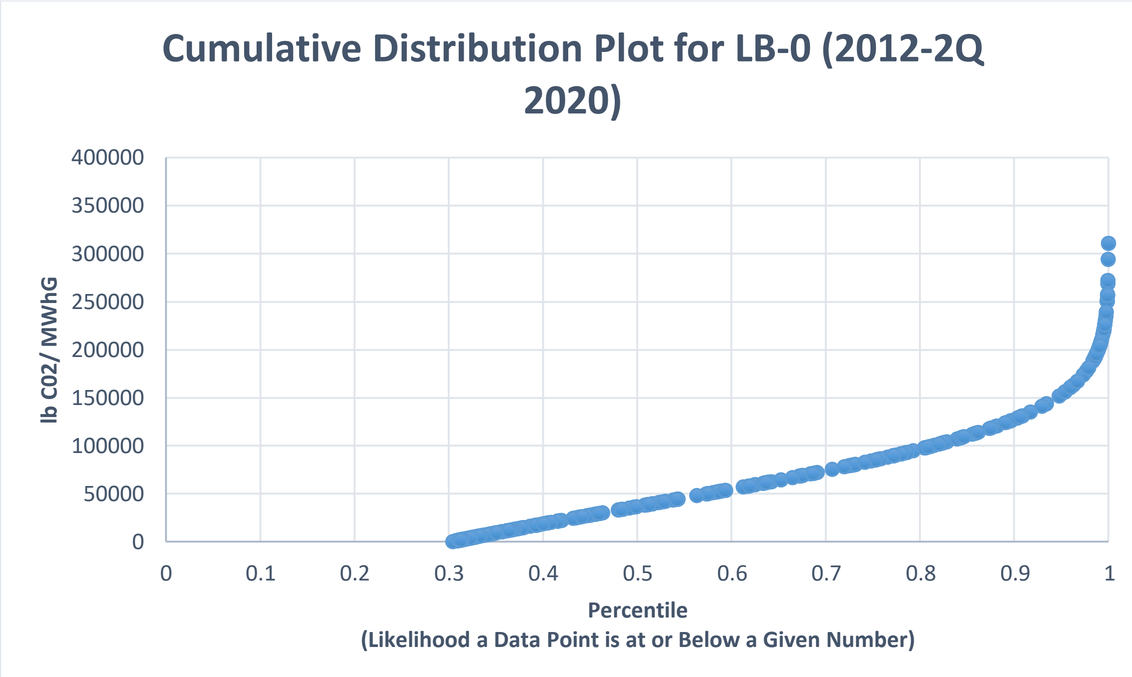

Figure C-2. Cumulative Distribution Plot for LB-0 (2012 – 2Q 2020).

The operating hours for each of the load bins identified above were evaluated to ensure there was an adequate number of data points in each of these bins to develop a standard. The following table shows the operating hours, by bin, across the baseline period. Initially, a baseline period of 2016 – 2019 was considered; however, as Figure C-3 below clearly demonstrates additional data points were needed for all load bins with the exception of LB-5 and thus the data for the first and second quarter of 2020 were added to the baseline period.

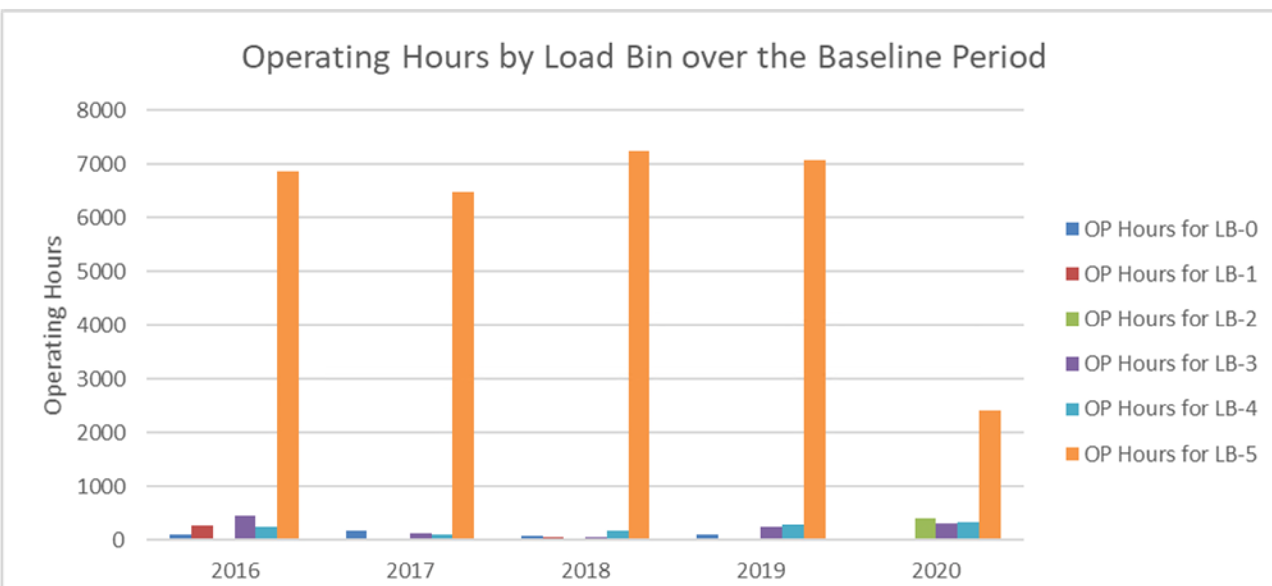

Figure C-3. Operating Hours by Load Bin over the Baseline Period.

The CO_2 emissions data for the baseline analysis was collected from a 40 C.F.R. Part 75 (Part 75) certified continuous emission monitoring system (CEMS) without the bias factors applied (unbiased CO_2 data) collected by LVP for compliance with the Acid Rain Program and submitted to the West Virginia DAQ in conjunction with their permit application for Permit R13-3495. LVP operates a CEMS that conforms to the Part 75 monitoring requirements which includes measuring carbon dioxide emissions. The LVP CO_2 monitor had an overall monitor availability of 99.53% over the baseline period. Only 0.47% of the baseline data contains CO_2 rates using Part 75 Substitution Procedures, as required under compliance with the Acid Rain Program. At this high level of monitor availability, the Part 75 Missing Data Procedures would only require LVP to take the average of the hour before and the hour after the period of the missing CO_2 readings.[4] During the baseline period, only 169 hours contain substituted data out of 35,937 operating hours. Thus, there is no concern for the baseline containing substituted data for CO_2 emissions.

The stated purpose of Part 75 "is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2) emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program. . ."[5] The purpose of the Part 75 monitoring requirements is to quantify the mass emissions released from an affected unit to be used in an emissions trading program. The data methodology under Part 75 was not selected for the baseline analysis because data collected in accordance with Part 75 is required to be adjusted on an annual basis based on results from the Relative Accuracy Test Audit (RATA) whereas the unbiased data collection methodology under 40 C.F.R. Part 60 is not subject to an annual adjustment factor. Part 75 requires the use of substitute data when there is missing data due to or caused by CEMS unavailability. The substitution procedures are designed to prevent operators from manipulating the trading programs to their advantage and are designed to be punitive in nature by intentionally inflating the substituted values.

The ACE emission guidelines require the standards of performance to be a rate-based limit in terms of CO_2 emitted per energy output (e.g. lbs of CO_2/MWh). This is different than the mass emission limits (tons/year) required under Part 75.

The selected methodology for analyzing and establishing the LVP baseline is based on requirements for new units or existing revised or modified units subject to 40 C.F.R. Part 60, Subpart TTTT, *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*. 40 C.F.R. Part 60, Subpart TTTT was chosen because it establishes procedures for monitoring CO_2 emissions to demonstrate compliance with a CO_2 emission rate. These procedures allow for the use of Part 75 monitors with a few exceptions which are:

- The data must be unadjusted exhaust gas volumetric flow rates. No bias adjustment factors applied to the exhaust flow rate data.

- Exclude full scale range of any continuous emission monitoring system for any parameter used to determine the hourly CO_2 mass emissions.

- Exclude data that the substitute data provisions of 40 C.F.R. Part 75 would be applied to determine the hourly CO_2 mass emissions.

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[4] 40 C.F.R. § 75.31(b)(1).
[5] 40 C.F.R. § 75.1(a).

Using unbiased data to determine the baseline emissions rate, to establish the standards of performance, and to demonstrate compliance, allowed West Virginia to analyze the LVP data without introducing additional variability beyond the variability inherent in the measurement systems. The relative accuracy for CO_2 monitors can be as much as 10.0 percent and for flow meters can be as much as 10.0 percent.[6]

The monitoring, recordkeeping, testing, and reporting methodology to demonstrate compliance with the established standard under Permit R13-3495 is consistent with the data methodology used to establish the standards of performance and is based on 40 C.F.R. Part 60, Subpart TTTT. The exception to this was the inclusion of Part 75 substitute data in the baseline data when the CO_2 CEMS was not available for 169 hours (7 days) during the 4.5 years baseline period as discussed above. The standards of performance supporting calculations, required by 40 C.F.R. §60.5740a(a)(6)(ii), are provided in Appendix F to this State Plan.

Level 1 Standards of Performance Discussion LB-0

Load Bin 0 (LB-0) for the SB1 unit is defined as the operating range at or below 40% of the unit's gross rating (i.e., 0-313 MWhG). This is the largest operational range and it includes periods of startups, shutdowns, and the operational time transitioning up to and down from minimum stable load. Under the ACE emission guidelines, work practice standards in lieu of a numerical emission rate during this phase of operations are not allowed. Although the load bin standard established for LB-0 is much higher than the load bin standards established for the other load bins, the established standard is justified, as explained in this section.

Setting an appropriate standard of performance for LB-0 is unique for two primary reasons. One, the LVP unit operates below its minimum stable load rate only when starting the unit up and when shutting the unit down and two, the CO_2 emissions rate is on a gross electric output basis (lbs/MWhG). The gross electric output basis is used because for most of the time operating in LB-0, there is no power being generated.

Although the LB-0 emissions rates are much higher than those in the other operating load bins, the time spent in LB-0 is much lower, thereby resulting in a small fraction of emissions being generated during SUSD operations. Startup and shutdown of the LVP unit make up less than 1% of the total operating hours in the baseline period data set. See Figures C-4 and C-5 below.

[6] 40 C.F.R. Part 75, Appendix A, *Specifications and Test Procedures,* sections 3.3.3 and 3.3.4.

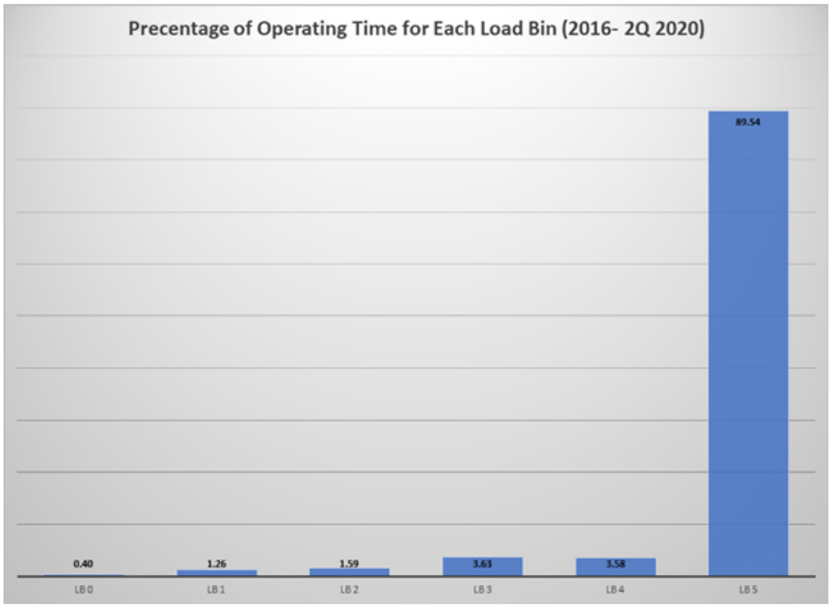

Figure C-4. Percentage Operating Time for each Load Bin.

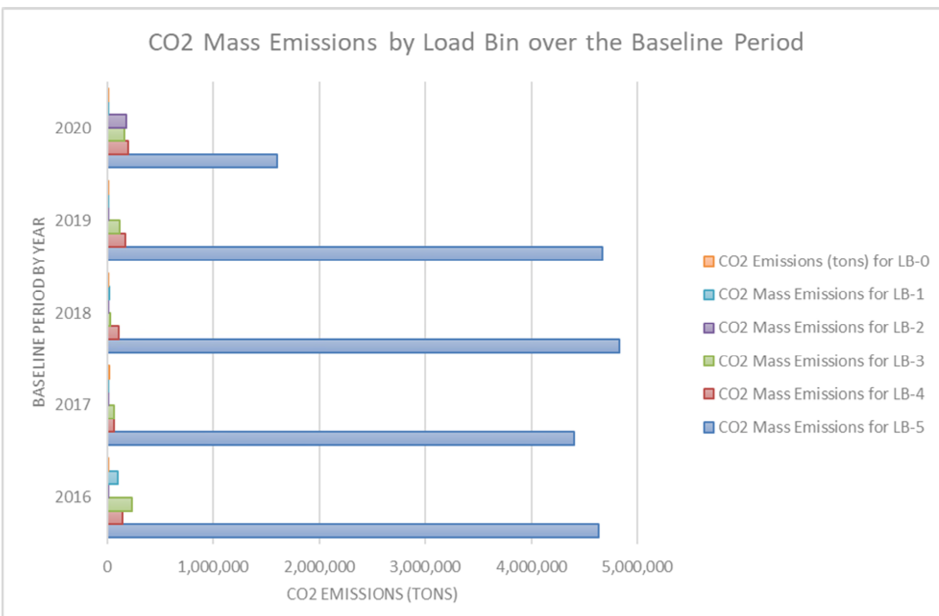

Figure C-5. CO_2 Mass Emissions by Load Bin over the Baseline Period.

Fundamentally, all factors incentivize LVP minimizing the time operating in LB-0 because costs are generated; however, there is no revenue being generated while operating in this load bin. The LVP unit has regimented control logic with established time durations, as well as other critical physical design limitations that force the unit to be either starting up or shutting down – there is no real steady state operation in LB-0. The LVP unit is moved to LB-1 and above as quickly as operationally possible, limited only by design and/or operational challenges in safely ramping up the load and maintaining unit operational stability while moving out of LB-0. If the operators have issues with the unit during this phase, the operators either immediately address the issue online or shut down the unit to enact repairs offline. Factors such as vibration, fuel feed, and other operations and maintenance (O&M) aspects can cause a reduced ramp rate, but these are to be expected, and minimized by the operations staff. Based on all of these factors, the LB-0 separate calculation is necessary and appropriate, overall emissions from this calculation encompass a very small part of overall unit emissions, and all economic and operational factors encourage the unit to move out of LB-0 as quickly as is safely possible.

The HRI from the candidate technologies in the ACE emission guidelines have little to no effect on improving the LVP unit's heat rate or CO_2 emissions during startup and shutdown events. Typically, base loaded units like LVP are projected to startup and shutdown a few times a year. Figure C-6 below provides a graphical representation of the CO_2 emission rates observed by the LVP unit since the unit started commercial operations. This graph along with the discussion in this section demonstrates that although the standard of performance developed for LB-0 is much higher than the other load bins, the standard is reasonable.

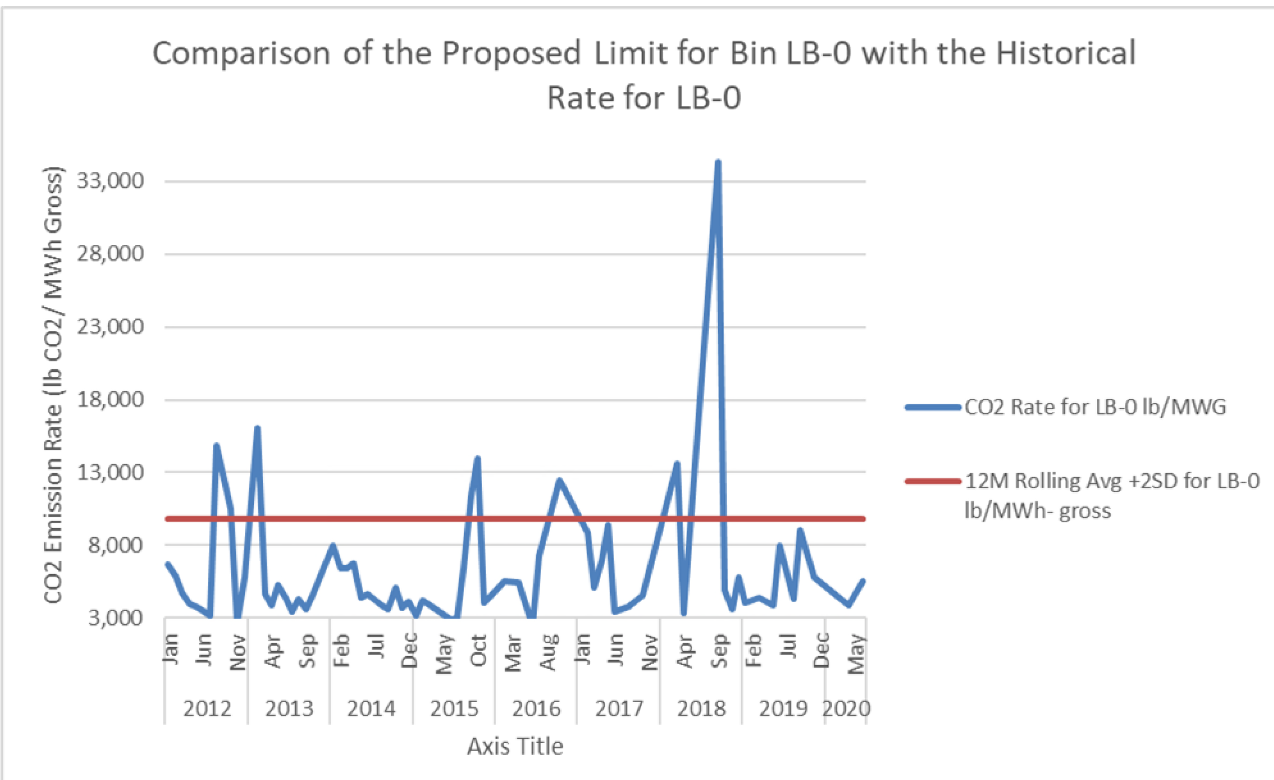

Figure C-6. Comparison of the Proposed Standard for Bin LB-0 with the Historical Rate for LB-0.

A compliance period of a calendar year was chosen for consistency with the other load bins and explained in more detail in the section discussing the other load bins. Figure C-6 above shows the actual monthly CO_2 emissions that occurred when the unit was operating at or less than 313 MWh on a gross basis. This graph demonstrates the need for the LB-0 standard to be averaged over a calendar year basis, as it shows the variability of SUSD rates over the history of the LVP SB1 unit.

While operating in LB-0, the EGU is being synchronized (synced) with the electrical grid. After the EGU is synced with the grid, the load on the EGU is quickly increased to just above its minimum load of 40% to be ready for PJM to dispatch the EGU to its desired load. At that point, the unit generates revenue for the operator (LVP). There is no benefit for LVP to operate in LB-0 other than for startup or shutdown purposes. In addition to the economic considerations, it is physically hard on the equipment with the vibrations the equipment encounters prior to establishing the minimum stable load. LVP is a merchant power plant; meaning, that it is not regulated by the Public Service Commission (PSC) and cannot seek relief from the rate payers. Power plants operate most efficiently at base load operations and are most profitable when running at base load conditions. It is the preference of LVP to operate within load bin LB-5 as often as possible and minimize the time in LB-0.

The standard of performance for LB-0 was developed using the same statistical analysis that was used in developing the standards of performance for the other load bins LB-1 through LB-5. The discussion and justification for using the statistical analysis tools is provided below for the development of the Level 1 standards for LB-1 though LB-5 that follows.

A discussion of the data used for the analysis, the calculations, and the data used for the baseline analysis is provided in Appendix F.

<u>Level 1 Standards of Performance Discussion LB-1 through LB-5</u>

The proposed load bin standards for each of the load bins identified as LB-1 through LB-5 were calculated by adding two times the standard deviation (SD) to the baseline average (determined on a 12-month rolling average) for each of these load bins. The calculations are explained in more detail in Appendix F to the State Plan. The justification for using two times the standard deviation and the statistical approach to establish the load bin standards follows. Compliance with the standards of performance is calculated on a weighted average based on the operating time in each of the load bins during the compliance period. The weighted average equations are provided in Appendix F of the State Plan.

The average of the monthly data converted to a mass rate of CO_2 per energy output (electricity generated), for the normal operation bins was compiled. The monthly average, standard deviation, kurtosis, and skewness of the respective load bin is illustrated in Table C-3 below.

Table C-3. Statistics of 12-Month Rolling Average by Load Bin.

Descriptive Statistics	LB-0	LB-1	LB-2	LB-3	LB-4	LB-5
Mean (lb/MWh- Net)	7,568	2,183	2,050	1,998	1,966	1,916
Standard Error	287	5	6	4	3	3
Median (lb/MWh- Net)	7,856	2,185	2,047	1,999	1,970	1,927
Standard Deviation ((lb/MWh-Net)	1,148	24	29	26	18	21
Sample Variance	1,401,199	580	860	686	338	440
Kurtosis	0.29	-0.50	-1.23	-1.27	-0.79	-1.60
Skewness	-0.69	-0.02	-0.16	-0.32	-0.36	-0.31
Range (lb/MWh- Net)	4,230	88	98	81	67	58
Minimum (lb/MWh- Net)	5,193	2,140	1,999	1,955	1,931	1,884
Maximum (lb/MWh- Net)	9,423	2,229	2,096	2,036	1,998	1,942
Confidence Level (95.0%)	608.6	10.7	12.1	9.1	6.0	6.5

Kurtosis and skewness are indicators of the normal distribution of data. Kurtosis is a measure of whether the data are heavy-tailed or light-tailed relative to a normal distribution. For an ideal normal distribution curve, kurtosis should approach zero. Kurtosis above +1 indicates a peaking curve and values less than -1 indicate the curve is flattening. The skewness for data with a normal distribution is zero.

A standard deviation (SD) is the measure of the "spread" of a data set around its mean value and is a concept integral to this analysis and allows for a proper understanding of the sample data, as well as assisting in predicting future performance with an appropriate degree of uncertainty. The Merriam-Webster dictionary defines standard deviation as a parameter that indicates the way in which a probability function or a probability density function is centered around its mean and that is equal to the square root of the moment in which the deviation from the mean is squared. It is an important concept when analyzing data and predicting future performance with an appropriate degree of uncertainty.

The SB1 unit has spent most of its runtime (>92% from 2016 through 2020) in LB-5 at generation loads greater than 689 MWG (Gross). The data in LB-5 is of high quality with many samples held tightly around the mean, thereby very accurately reflecting the units CO_2 emissions performance in that load bin. An indicator of this data quality is using the sample standard deviation which measures the typical distance between each data point and the mean (average). As shown in Table C-3, the SD for the data in LB-5 is very low, so by incorporating the calculated mean, as well as 2 times the standard deviation, the Bin Standard (Mean + 2 x SD) is a very accurate representation of where most of the actual data has, and future data will, fall based on this load range. Statistically speaking, 95% of the data will fall within 2 standard deviations of the mean.

The concept of using a sample SD is reliable, and meaningful in predicting future performance based on the sample data from 2016 through second quarter 2020 because 95% of the data fits within this standard. The standard deviation statistical approach accounts for normal operational and measurement variability. Measurement accuracy alone can account for a larger acceptable variation than the 2 SD calculated from the baseline data and shown in Table C-3. The relative accuracy for CO_2 and flow monitors can be as much as 10.0 percent.[7]

For the reasons discussed above, the 2 SD approach is appropriate and reasonable for establishing the standards of performance for LVP for LB-1 through LB-5. For consistency purposes, the standard of performance for LB- 0 was developed using the same 12-month rolling average approach plus two times the standard deviation.

As discussed in Section D of this Appendix C, it was determined there are no additional heat rate improvements (HRI) that can be gained for LVP from the BSER candidate technologies. Therefore, there is no HRI subtracted from the average baseline + 2 SD calculation to establish the standards of performance.

The ACE emission guidelines do not specify how the standards of performance should be established, leaving discretion to the States. There was not a specific guidance document or model rule that outlines how emissions data should be processed or how the standard of performance should be developed. The ACE guidelines do require the established standards of performance to be quantifiable, verifiable, permanent, and enforceable for each designated facility[8].

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[7] 40 C.F.R. Part 75, Appendix A, *Specifications and Test Procedures,* sections 3.3.3 and 3.3.4.
[8] 40 C.F.R. § 60.5755a(b).

Rather than complying with six different load bin standards throughout a compliance period, a weighted average approach was established to comply with the load bin standards. Compliance with the CO_2 weighted average is specified in condition 4.4 of Permit R13-3495 and is based on the operating hours spent within each of the load bins LB-1 through LB-5. The decision to have LVP demonstrate compliance based on a weighted average was done to ensure the established limits are practicably enforceable over the compliance period. Compliance with LB-0 is determined separately based on the amount of time spent within this load bin because as previously mentioned the LB-0 standard was developed in terms of gross electric generation. Compliance using weighted average standards are not a new concept under the Clean Air Act (i.e. nitrogen oxides (NO_x) standards for different fuels under Subparts Da[9] and Db[10] of 40 C.F.R. Part 60) or West Virginia's State Rules established under the authority of the West Virginia State Code (i.e. 45 CSR 7[11], 45 CSR 21[12]). The weighing mechanism must be common for the bin standards and measurable. The equations used to determine the weighted average standard for Level 1 (normal operations) are provided below and are identified as Equation 1.

Equation 1.

$$Level\ 1\ CO_2 weighted\ Avg =$$

$$\frac{\sum OPHL1_{LB-1} \times CO2_{LB-1} + \sum OPHL1_{LB-2} \times CO2_{LB-2} + \sum OPHL1_{LB-3} \times CO2_{LB-3} + \sum OPHL1_{LB-4} \times CO2_{LB-4} + \sum OPHL1_{LB-5} \times CO2_{LB-5}}{\sum OPHL1_{total}}$$

Where:

Level 1 CO_2 weighted Avg =

Level 1 CO_2 Weighted Average Standard for the compliance period in terms of pounds of CO_2 per MWh (net).

$\sum OPHL1_{LB\text{-}1}$ = Total Level 1 operating hours in Load Bin 1

$CO2_{LB\text{-}1}$ = The CO_2 standard for Load Bin 1 in terms of pounds of CO_2 per MWh (net)

$\sum OPHL1_{LB\text{-}2}$ = Total Level 1 operating hours in Load Bin 2

$CO2_{LB\text{-}2}$ = The CO_2 standard for Load Bin 2 in terms of pounds of CO_2 per MWh (net)

$\sum OPHL1_{LB\text{-}3}$ = Total Level 1 operating hours in Load Bin 3

$CO2_{LB\text{-}3}$ = The CO_2 standard for Load Bin 3 in terms of pounds of CO_2 per MWh (net)

$\sum OPHL1_{LB\text{-}4}$ = Total Level 1 operating hours in Load Bin 4

$CO2_{LB\text{-}4}$ = The CO_2 standard for Load Bin 4 in terms of pounds of CO_2 per MWh (net)

$\sum OPHL1_{LB\text{-}5}$ = Total Level 1 operating hours in Load Bin 5

$CO2_{LB\text{-}5}$ = The CO_2 standard for Load Bin 5 in terms of pounds of CO_2 per MWh (net)

$\sum OPHL1_{total}$ = Total Level 1 operating hours excluding hour operating in Load Bin 0 (LB-0)

The standard must be constraining, yet reasonably achievable. One of the main reasons to separate the startup/shutdown load bin (LB-0) from the weighted average approach for normal operations is to not allow

[9] 40 C.F.R. § 60.44Da(a)(2).
[10] 40 C.F.R. § 60.44b(b).
[11] 45 C.S.R. 7 § 4.1.
[12] 45 C.S.R. 21 § 4.1.a.4.

the weighting from LB-0 to adversely influence the weighted average standard to the point that the standard is no longer constraining. None of the BSER candidate technologies, including the O&M improvements, should have any potential impact on reducing startup and shutdown emissions. The CO_2 emissions that occur during SUSD is practically insignificant when compared to the rest of the load bins[13].

The compliance period established for LVP in Permit R13-3495 is on a one-year calendar basis, as justified later in this section. LVP's SB1 unit has been operational for only eight and a half years. The emissions data to demonstrate the standard is constraining or achievable is limited because LVP is a relatively new unit. Due to the lack of historical data, the annual actual emissions (including data from the baseline period) and the corresponding standard of performance based on the weighted average spent in the each of the established load bins LB-1 through LB-5 was determined and charted in Figure C-7 below.

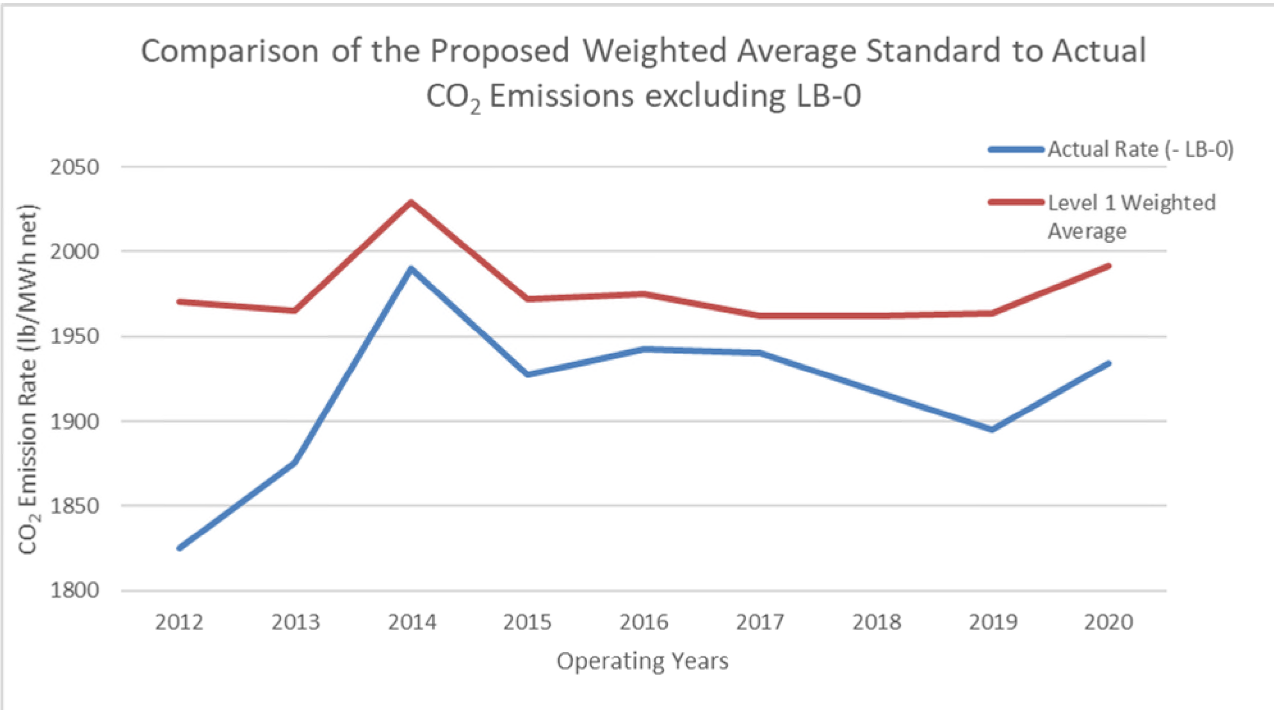

Figure C-7. Comparison of Weighted Average Standard to Actual CO_2 Emission Rate excluding LB-0.

The curves in the above figure excluded the CO_2 emissions data when the unit was operated at or below the minimum load (313 MWh – gross). The margin of compliance between the calculated weighted average standard and the actual CO_2 emissions rate is greatest in calendar years 2012 and 2013. This is expected for a new unit. Any new unit is expected to be at its most efficient after initial startup of the unit. The greatest compliance margin occurred in 2012, with a rate of 7.4%. The compliance margin quickly decreased to 1.9% in calendar year 2014.

From the initial startup until 2015, the SB1unit experienced original design and construction related defects that caused forced outages of the unit. These design and construction issues were corrected during a rehabilitation outage in 2015 that encompassed all major components of the plant. After LVP addressed

[13] See. Figure C-3 of this Appendix C.

these issues, the unit began improving its efficiency and the compliance margin increased slightly. This margin decreased to 1% in 2017. In 2017, LVP switched its source of fuel (coal) to a better-quality fuel with less ash and a higher heating value.

The weighted average standard curve in Figure C-7 levels out from 2016 through 2019. This flatness is due to the unit being operated at its maximum load conditions for extended periods, which is the most efficient operating mode for this unit. The compliance margin is beginning to decrease in 2020, which is mainly due to the unit operating at lower and less efficient loads (LB-3 and LB-4) because of decreased demand in the first two quarters of 2020. The average compliance margin over this period is just over 3%.

Neither the ACE emission guidelines nor guidance from the U.S. EPA provide what would be an acceptable margin of compliance for proposed standards of performance. One benchmark that is currently available as an indicator that the proposed standard is constraining and reasonably achievable is from comparing the proposed standards of performance against 40 C.F.R. Part 60, Subpart TTTT, *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*. The U.S. EPA established carbon dioxide standards for new and reconstructed EGUs under Subpart TTTT of 40 C.F.R. Part 60 (NSPS). The standard established for new EGUs is 1,400 lb per MWh on a gross generation basis. The standard for reconstructed EGUs is 1,800 lb per MWh on a gross generation basis. The compliance with the reconstruction CO_2 standard is based on a 12-month rolling basis of gross generation. This standard includes all times CO_2 emissions are emitted.

Figure C-8 below illustrates the calculated LVP weighted average monthly CO_2 emission rate on a gross generation basis from 2012 through the 2nd Quarter of 2020 based on both a 12- and 36-month rolling averages. For this demonstration, the gross basis was used to compare the actual emission rates in consistent terms with the NSPS standard for reconstructed EGUs. The LVP monthly rates in Figure C-8 includes all CO_2 emissions in the rate, which includes SUSD and emissions less than the minimum stable load that occurred in LB-0. The inclusion of the LB-0 emissions in the actual emission rate was also done to compare the emission rates in consistent terms with the NSPS standard for reconstructed EGUs.

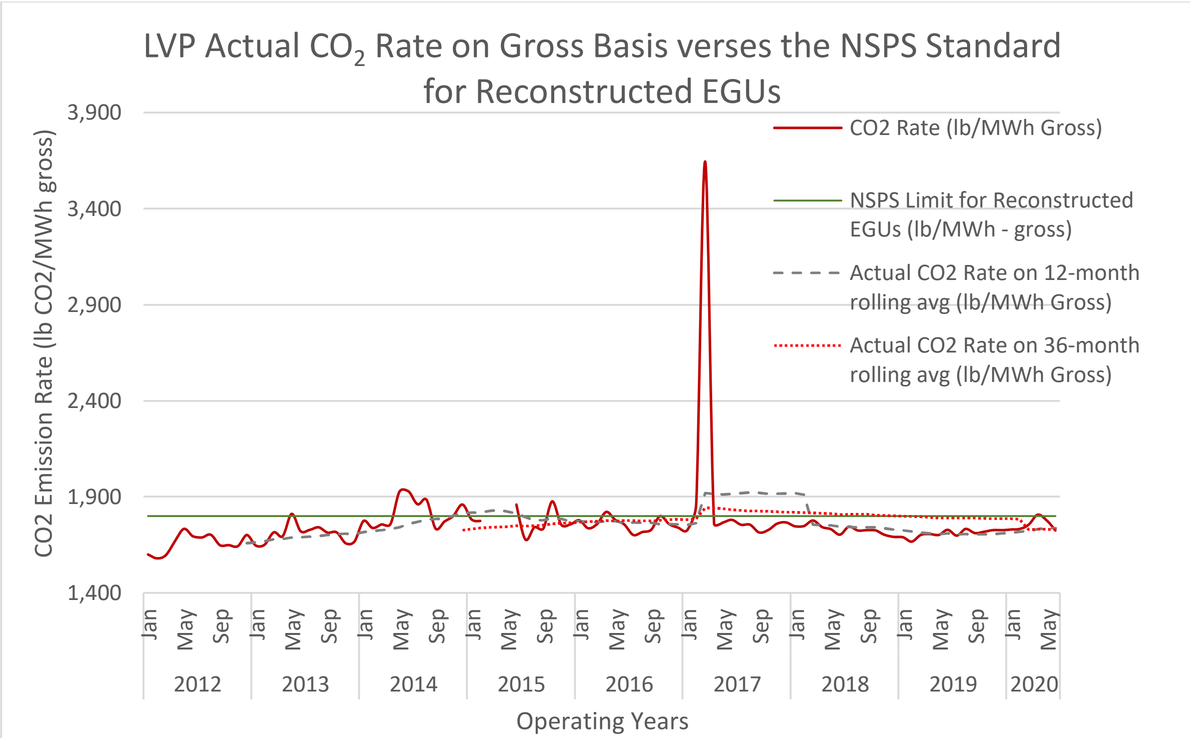

Figure C-8. LVP Actual CO_2 Rate on Gross Basis verses the NSPS Standard for Reconstructed EGUs.

LVP CO_2 mass emissions were converted into a monthly CO_2 rate on a gross generation basis. Using this monthly CO_2 rate, a 12-month rolling average was developed and compared to the NSPS reconstructed EGUs standard. Figure C-8 shows that even with HRI implemented, the unit cannot maintain compliance with the reconstructed standard. A second rolling average was developed to determine if a longer averaging period would allow the unit to comply with the standard.

A rolling average of 36 months was developed, and it smooths out the LVP CO_2 rate over the years. This extended averaging period still would not allow the unit to achieve compliance with the standard based on past historical CO_2 emissions and operating data. The issue of not being able to achieve compliance during 2017 and 2018 is due to two startup events that occurred in October of 2016 and February and March of 2017. To explain, a rolling average includes the previous 12 or 36 months at any given time (depending if it is a 12-month or 36-month basis) and therefore, in this instance, includes both the October 2016 startup event and the Feb/March 2017 startup event. The magnitude, duration and close proximity of these past events prevents the unit from complying with the reconstructed standard regardless of the averaging period, which reinforces the need to allow the source to demonstrate compliance with a separate standard for startup and shutdown periods.

One cannot directly compare LVP's proposed standard with the reconstructed standard. However, the basic method (12-month rolling average plus two standard deviations) that was used to develop the proposed LVP standards of performance can be recalculated on a gross generation basis. Gross generation is the amount of electricity generated from the unit. Net generation is the gross energy output (generation) minus the parasitic load (energy consumed by the unit to operate) of the unit. Parasitic load includes energy used to drive the pumps, fans, pulverizers, etc., required to operate the unit. The net electric generation is the actual amount of electricity sent to the electricity grid.

To compare LVP's proposed weighted average CO_2 standard with the NSPS limit for reconstructed EGUs, the LVP data was reprocessed on a gross basis in the same manner that was used to develop the standards for each of the load bins LB-1 through LB-5, which yielded the values provided in Table C-4 for each of these bins.

Table C-4. LVP Load Bin Standards Adjusted to Gross Basis.

Load Bin	12 Month Rolling Avg + 2SD (lbs CO_2/MWh-gross)
LB-1	1929
LB-2	1897
LB-3	1845
LB-4	1802
LB-5	1762

Using the values in Table C-4 for the corresponding bins, the weighted average CO_2 standard on a gross basis was determined for each operating year from 2012 through 2Q 2020 and plotted in Figure C-9 below.

Other than in 2014, the weighted average CO_2 standard on a gross basis is more constraining than the NSPS reconstruction standard for EGUs. In 2020, the proposed weighted average and actual CO2 rate is approaching the NSPS standard again. In the 1st and 2nd Quarters of 2020, LVP's operational mode shifted to a cycling load mode, which drove the weighted average and actual emission rate closer to the NSPS standard.

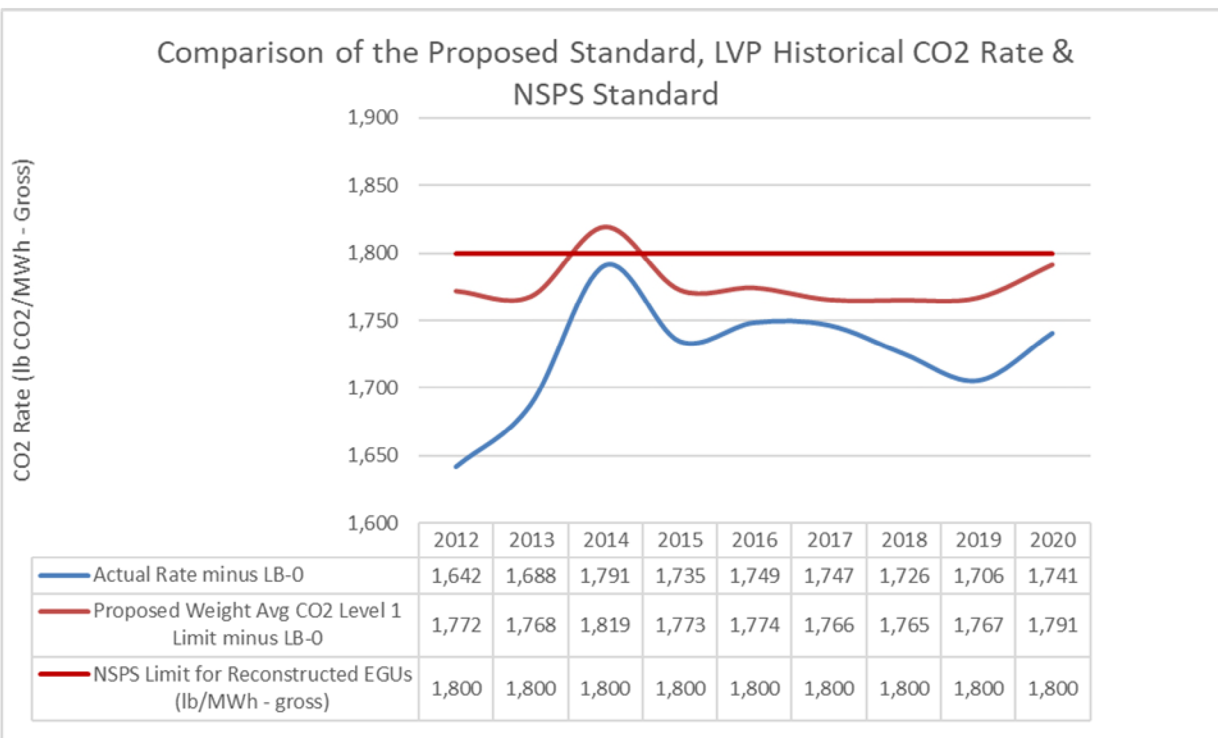

Figure C-9. Comparison of the Proposed LVP Standard, LVP Historical CO_2 Rate & NSPS Standard. (LB-1 through LB-5)

West Virginia's proposed weighted average CO_2 standard for LVP for LB-1 through LB-5 is lower than the standard established for reconstructed EGUs under 40 C.F.R. Part 60, Subpart TTTT. Although West Virginia determined a separate standard for LB-0 to ensure a constraining limit for LB-1 through LB-5 and for reasons previously discussed, Figure C-6 along with the discussion in this section demonstrates that the proposed standards of performance developed for the LVP SB1 unit are reasonable and constraining.

Level 2 (Impaired Operation) Standards of Performance Discussion

West Virginia developed alternative standards of performance for impaired operation scenarios because the standards of performance developed for normal operation may be too constraining in the event of a high impact, but low probability event that could cause damage to the unit and have long lead times for repair materials to be manufactured that could cause the LB-1 unit to operate at a significantly reduced efficiency for a specific period of time.

There are a significant number of scenarios in which an unexpected unavoidable equipment failure or condition monitoring finding may require a critical piece of equipment to be taken out of service. Such a scenario would be expected to have an impact on heat rate, efficiency, and economic viability of the generating unit. The impacts of these equipment failures can be reasonably categorized and estimated and therefore, should be contemplated in formulating the standards of performance for LVP. To accommodate these potential scenarios, the idea of a Level 2 compliance standard was developed, to account for the possibility of equipment failure scenarios and resulting efficiency losses listed below, as well as similar events.

Several realistic scenarios that have occurred at LVP, or may reasonably be expected to occur, are presented below along with their anticipated effect on unit's efficiency. These scenarios are representative of a wide variety of failure mechanisms; however, they are not all-encompassing, and it is not the intent of this demonstration to describe every possible failure scenario in detail, merely to demonstrate the need for proposed Level 2 standards of performance.

A baseline unit operation scenario is provided in Table C-5 for the purpose of providing a comparison of failure scenarios and to estimate the heat rate losses.

Scenario 1 – High Backpressure:

The case of failure of the circulating water pump, portion of the cooling tower, or portion of the condenser would have a minimal impact on the amount of net generation the unit could produce; however, each of those scenarios would have a 7 – 10% impact on the efficiency due to increased back pressure on the turbine in the condenser.

In the case of a circulating water pump failure, LVP has existing O&M strategies in place to largely mitigate this risk. Part of the mitigation is proper operation and oversight, proper maintenance, advanced condition monitoring with items such as continuous vibration and temperature monitoring, and spare parts inventory management. With the referenced strategies, LVP has expressed that even though the efficiency impact of such a failure is significant, it can be handled in manner to get back to normal condition with appropriate speed to largely mitigate compliance risk of CO_2 compliance when averaged over the reporting time period within a reasonable compliance margin.

Scenario 2 - High Backpressure and L-0 Removed:

One such example is the Low Pressure (LP) Turbine L-0 blading. The L-0 blading on an LP Turbine is the final stage of converting steam energy into mechanical energy to be converted to electrical energy at the generator. To convert as much energy as possible, these blades are very long which creates significant stress on the blades due to forces placed on them. Additionally, since this is the last stage of blading, the steam has started to transition into saturation temperatures becoming wet steam, creating an ongoing erosion issue on the leading edges of blades.

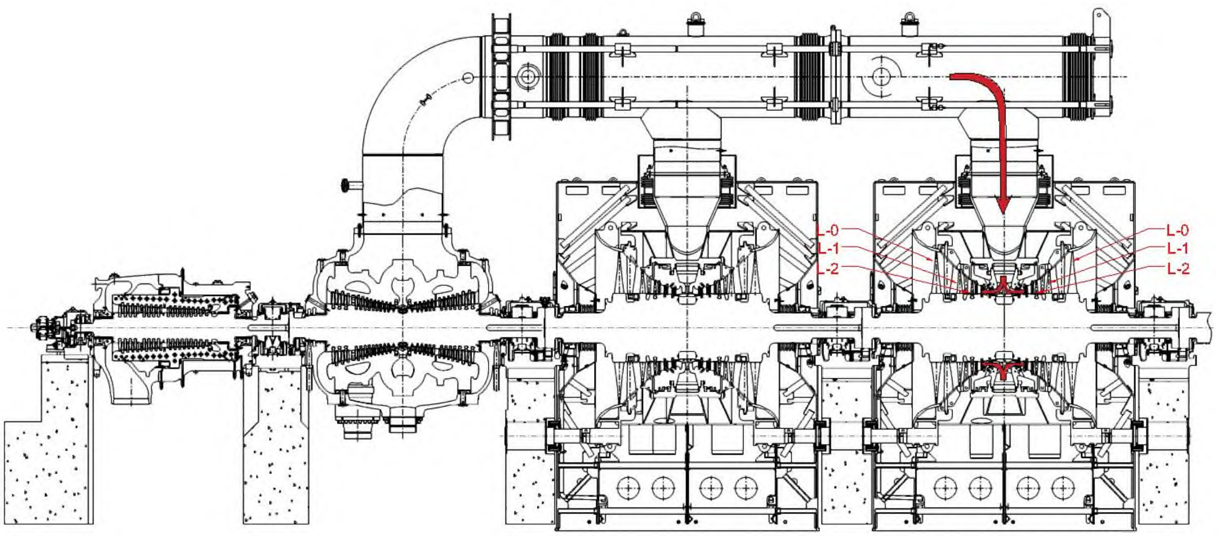

Figure C-10. Longview Power Steam Turbine Overview.

As illustrated in Figure C-10, the L-0 blading is the last row of blades and they are the largest blades in system.

L-0 blading (the last rotating row) in LP Turbines has been an ongoing industry wide design and reliability issue for equipment manufacturers and plant engineers for many years. This row experiences a unique range of operating conditions that place significant stresses on the material. LVP has an extensive advanced non-destructive examination technologies program to monitor the condition of the blading. LVP utilizes these advanced examinations approximately every 25,000 hours of operation (approximately every 3 ½ years) or after a turbine trip with a loss of condenser vacuum due to additional significant stresses on the LP Turbine blading. The effort and expense is completed proactively with the intention of identifying an issue in a very early stage that can be corrected or mitigated prior to a complete failure event; however, it is feasible to find an indication that would require immediate action or mitigation.

Even with these proactive measures in place, there is a risk of turbine blade failures that would allow for continued, albeit less efficient, facility operation during extensive repairs. A row of L-0 blading is approximately $1MM material cost per row (2 or 4 rows would be needed) and a 1-year lead time due to the size of forgings and specialty materials and machining required.

In 2017, the plant experienced a failure of an L-2 LP turbine blade that damaged the entire L-2 row, as well as L-1 and L-0 rows. Inspection required the L-2 and L-1 blading to be replaced. LVP contemplated removing L-0 blading due to the damage on blades. If this had been required, an approximate 15 - 30% MW load loss and a 14% impact to unit efficiency would have been observed. This temporary measure would allow continued operation and preservation of some revenue thus maintaining the business until the parts could be supplied. Replacement of L-0 blades would require a 5 to 6-week outage. This high impact scenario would result in having to operate the unit out of compliance for well over a one-year time period if not addressed through some reasonable permit relief mechanism such as the proposed Level 2 standards.

Scenario 3 – 7/8 HP Heaters Out of Service:

There are many cases where it may be required to run without feedwater heaters in service. Depending on the specific heaters or combination of heaters it can have an efficiency impact greater than 2.5%. The unit is designed to operate without these heaters and maintain normal emissions.

Table C-5: Heat Rate Impacts Considered for the Level 2 Standard.

	Baseline Scenario	**Scenario 1**	**Scenario 2**	**Scenario 3**
Unit Heat Rate (Btu/kWh Net)	8,857	9,509	10,241	9,085
Heat Rate Impact	0.0%	7.4%	14.2%	2.6%
% Rated Load	100.0%	93.5%	87.1%	98.1%
Unit Operating Load (MW Net)	700	655	609	686

There are equipment failures that can be reasonably managed via O&M best practices; however, there are real scenarios that cannot be avoided. To address these possibilities, West Virginia established a Level 2 standard of performance as an alternative operating scenario under condition 4.1.1.b of Permit R13-3495 that includes conditions that must be met to trigger the Level 2 standards of performance. The Level 2 alternative operating requirements include notification requirements, approval requirements, a root cause analysis, a corrective action plan submittal that includes timelines for repairs that is capped at twenty-four months, and reporting requirements.

The Level 2 standard is 10% higher than the Level 1 standards of performance during non-emergency operations. Given the range of efficiency losses calculated from the various failure scenarios and provided in Table C-5 above, West Virginia considers the 110% Level 2 criteria a reasonable accommodation that covers a range of possible scenarios while not automatically implementing a worst-case scenario in the event these or similar failure events occur over the life of the LVP unit, while also maintaining the intention of the ACE emission guidelines.

Market conditions and LVP unit's degraded state will ultimately decide whether the unit will operate. It is the role of the West Virginia DAQ to determine whether the source is or is not operating in compliance with the standard and what measures are adequate to bring the source back into compliance.

During periods when Level 2 in in effect, the standard for LB-0 is not adjusted. Equipment failures that affect the efficiency should not impair the CO_2 emission rate while operating in LB-0.

An equation similar to Equation 1, is used to determine the weighted average while the unit is operating within Level 2 conditions during the compliance period. See the following equations (Equation 2 and Equation 3).

Equation 2.

$$Level\ 2\ CO_2 weighted\ Avg =$$

$$1.10 \times \left(\frac{\sum OPHL2_{LB-1} \times CO2_{LB-1} + \sum OPHL2_{LB-2} \times CO2_{LB-2} + \sum OPHL2_{LB-3} \times CO2_{LB-3} + \sum OPHL2_{LB-4} \times CO2_{LB-4} + \sum OPHL2_{LB-5} \times CO2_{LB-5}}{\sum OPHL2_{total}}\right)$$

Where:

Level 2 CO_2 weighted Avg =

Level 2 CO_2 Weighted Average Limit for the compliance period in terms of pounds of CO_2 per MWh (net).

$\sum OPHL2_{LB-1}$ = Total Level 2 operating hours in Load Bin 1

$CO2_{LB-1}$ = The CO_2 limit for Load Bin 1 in terms of pounds of CO_2 per MWh (net)

$\sum OPHL2_{LB-2}$ = Total Level 2 operating hours in Load Bin 2

$CO2_{LB-2}$ = The CO_2 limit for Load Bin 2 in terms of pounds of CO_2 per MWh (net)

$\sum OPHL2_{LB-3}$ = Total Level 2 operating hours in Load Bin 3

$CO2_{LB-3}$ = The CO_2 limit for Load Bin 3 in terms of pounds of CO_2 per MWh (net)

$\sum OPHL2_{LB-4}$ = Total Level 2 operating hours in Load Bin 4

$CO2_{LB-4}$ = The CO_2 limit for Load Bin 4 in terms of pounds of CO_2 per MWh (net)

$\sum OPHL2_{LB-5}$ = Total Level 2 operating hours in Load Bin 5

$CO2_{LB-5}$ = The CO_2 limit for Load Bin 5 in terms of pounds of CO_2 per MWh (net)

$\sum OPHL2_{total}$ = Total Level 2 operating hours excluding hours operating in Load Bin 0 (LB-0)

1.10 = Ten (10) percent increase of the Level 1 Limits.

To address times when the Level 2 standards occur during the compliance period, the same weighted average concept to be used to weight the standard during the compliance period based on actual operating hours for each of the levels.

Equation 3.

$$CO2\ Weighted\ Avg\ = \frac{(Level\ 1\ CO2\ weighted\ avg\ \times \sum OPHL1_{total}) + (Level\ 2\ CO2\ weighted\ avg\ \times \sum OPHL2_{total})}{\sum OPHL1_{total} + \sum OPHL2_{total}}$$

Where:

CO_2 weighted Avg =

CO_2 Weighted Average Limit for the compliance period in terms of pounds of CO_2 per MWh (net).

$\sum OPHL1_{total}$ = Total Level 1 operating hours excluding hours operating in Load Bin 0 (LB-0)

$\sum OPHL2_{total}$ = Total Level 2 operating hours excluding hours operating in Load Bin 0 (LB-0)

Unit Degradation Adjustment Factor (UDAF)

Coal-fired power plants conduct major outages to perform maintenance that cannot be performed while the EGU is in operation and must be done when the unit is out of service. These outages tend to be longer in duration, commonly lasting a few months. These outages are scheduled well in advance and are coordinated with the PJM RTO to ensure electrical grid reliability. Equipment degradation is observed between periods of major outages, with efficiencies gained following the tune-ups that occur during the major outages. Permit R13-3495 condition 4.1.1.c addresses degradation in the form of a unit degradation adjustment factor (UDAF).

LVP has been in commercial operation less than ten years; therefore, the SB1 unit has not gone through its first major outage and does not yet have any facility specific experience with how the equipment will respond following its first major outage and how much efficiency will be regained as a result of the major tune-up outage. For this reason, LVP conducted an extensive analysis of peer supercritical coal fired plants in PJM Interconnection to determine historical actual degradation rates over time. LVP downloaded publicly available data from S&P Market Intelligence to complete this analysis. Annual heat rate data was downloaded for all currently operating supercritical coal fired plants in the PJM Interconnection from 1994 through 2019 to provide a large sample size located within the same geographic region. This supercritical coal fleet is comparable to Longview Power in terms of similar atmospheric conditions, fuel supply, market conditions, and basic plant design.

LVP analyzed the peer fleet (PJM coal-fired operational supercritical units in operation since 1994) over the last 25 years as a basis for a recommended degradation rate. The recommended LVP degradation standard curve utilized the average starting heat rate in year 1994 and escalated heat rate by the recommended degradation curve of 0.4% annual increase with a 0.7% reduction (recovery) due to major maintenance recovery every 5th year. This is represented in Figure C-11 below. In reviewing the average trend, the result of the recommended degradation rate is significantly less as compared to the peer group over the last 25 years. The intent is to demonstrate an improved degradation rate over the historical demonstration of the peer group. Please note that a single unit data set will exhibit wider variability than the larger population represented by a fleet of similar units due to averaging of numerous variables.

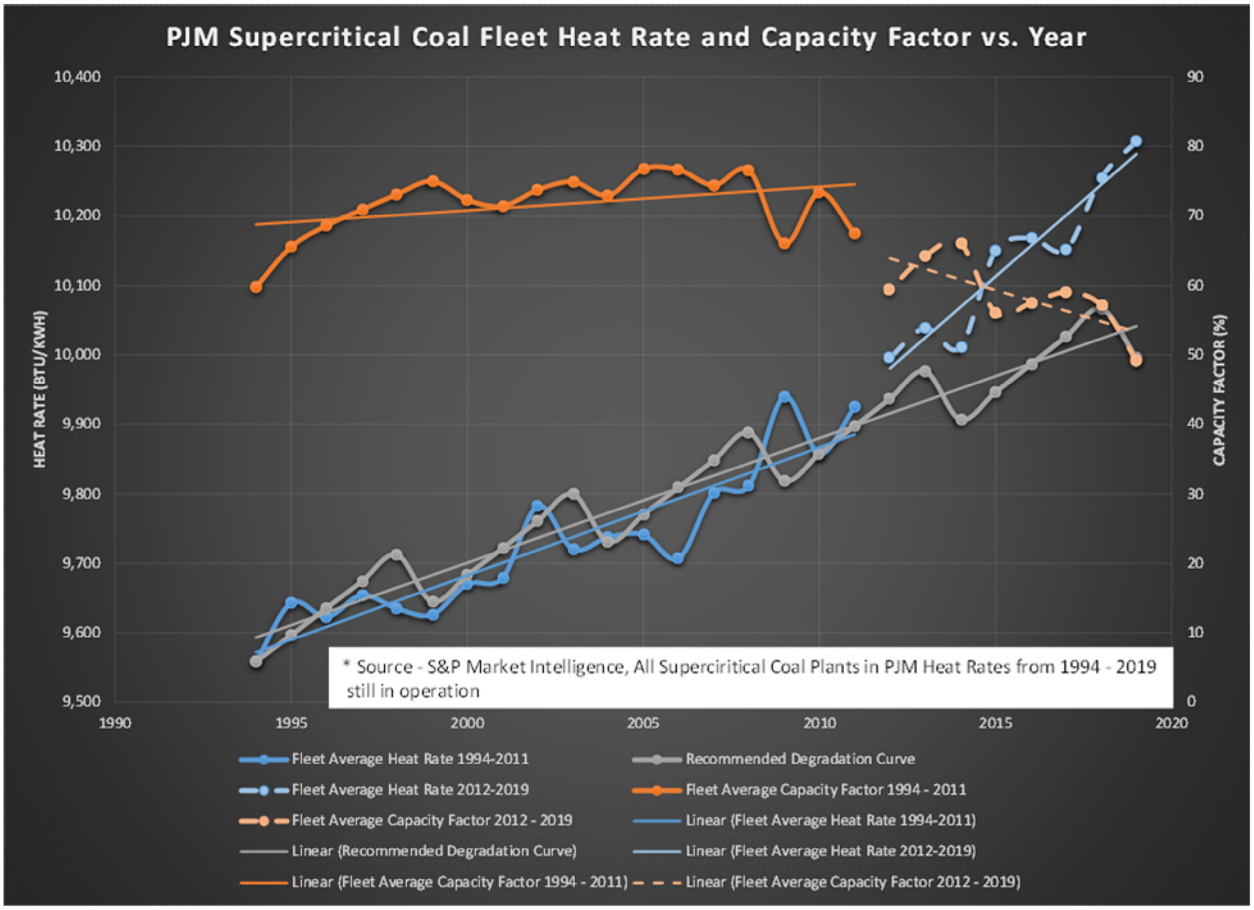

Figure C-11. PJM Supercritical Coal Fleet Heat rate and Capacity Factor versus Year.

There are two distinct time trends for the fleet data. First, from 1994 – 2011 there was an increasing trend in capacity factor that shows an increasing rate of change in heat rate. Starting around 2012, it is apparent that plant capacity factors for supercritical plants started to decline and the rate of increased heat rate increased at a much faster rate. This declining trend is related to the decline in the industry average capacity factor.

Figure C-12 has the degradation displayed in terms of percent per year and Cumulative percent over a 25-year period based on fleet data starting in 1994 as year zero. As seen on the annual percent per year over year trends, the reader will notice the fleet has large swings year over year. The cumulative results show how the recommended degradation curve would yield greater than 3% better performance over a 25-year period.

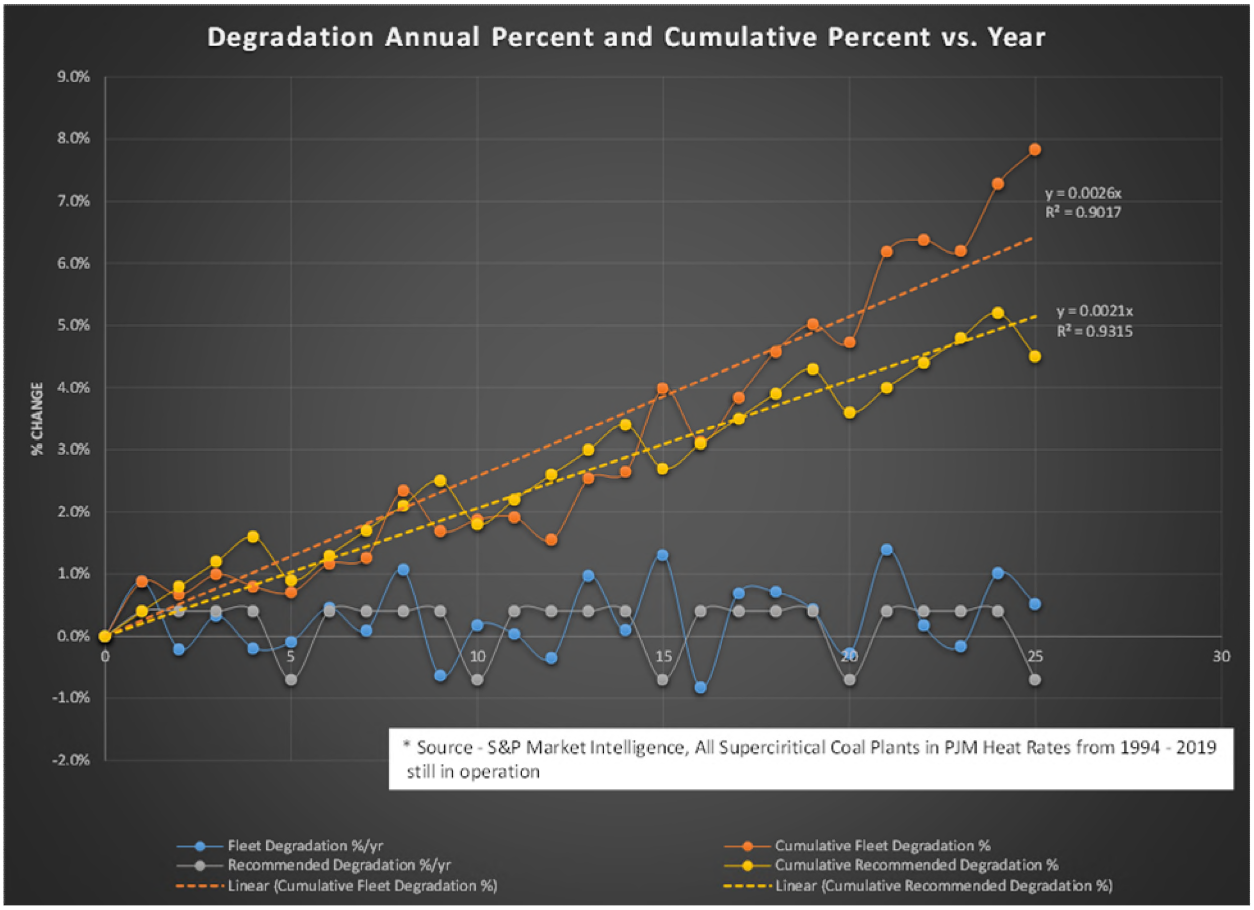

Figure C-12. Degradation Annual Percent and Cumulative Percent vs. Year.

LVP proposed that the above discussion justifies the proposed UDAF of 0.4% annually with a five-year recovery rate of 0.7%. The West Virginia DAQ permit engineer states the following in the Engineering Evaluation of Permit R13-3495 for LVP[14]:

> Using the HR from the LVP Online Performance Monitoring (OPM) system, degradation of the SB1 unit is difficult to observe. The unit's annual average HR performance has continued to improve nearly each year from 2016 to the present. Except for LB-2, the average heat rate by bin degraded from 2014 to 2015, which ranged from 5.5% for LB-1 to 0.4% for LB-5. This degradation occurred despite LVP's efforts to address the design and construction issues that affected the unit's reliability. The lack of HR data from the OPM system and heat rate improvements implemented at LVP in 2015 make it difficult to determine the unit's degradation rate.
>
> It would have been expected that resolving the design and construction issues would have improved the unit's heat rate from 2014 to 2015. From 2015 to 2016, the heat rate by bin improved except for LB-5, which degraded 0.5%. The OPM heat rate for this 2015 to 2016

[14] Engineering Evaluation of R13-3495; Longview Power LLC; Maidsville Facility, pages 41- 43

should have indicated an improvement across all the load bins because LVP completed installing all the BSERs at the beginning of 2016.

The writer believes the HR determined using the OPM supports LVP's proposed UDAF of 0.4% for each of the load bins as being conservative. There is not enough data to adequately determine whether the recovery rate is conservative. The unit has not undergone its first complete major outage to determine the actual recovery rate. Basing the proposed recovery rate on the recovery rate of the fleet is an acceptable methodology.

LVP believes that there is a period at the beginning of a new unit's operation when the unit operators are learning how to optimize the unit. LVP OPM data indicates that this unit optimization had occurred twice for their unit due to the rehabilitation project in 2015. The DAQ believes that the unit heat rate is decaying but the measured heat rate from OPM data is not indicating this due additional HRI. There is a point in the degradation rate (decay curve) of a new unit where the rate of decay will slow down. Based on Black and Veatch experience of the efficiency of coal fired power plants, Black and Vetch would a anticipate this change in the rate of decay to occur around 20 to 25 years of age.

EPA has proposed a revised carbon dioxide standard for combined cycle combustion turbines and EGUs. The DAQ looked to the EPA's proposed standard for guidance in determining the time frame for allowing the standard to be adjusted to account for the rate of decay. The proposed revised standard that would be applicable to LVP is 1,900 lb of CO_2 per MWh gross. EPA acknowledged that this standard should adequately account for degradation of the unit.

To compare this proposed revised standard with LVP's proposed standard, the proposed revised standard was corrected to a net basis by dividing the historical difference between gross verses net of 0.9, which equates to a net generation based value of 2,111 lb/MWh net. The 0.9 is LVP historical the ratio of gross to net generation.

The projected Load Bin 5 standard is 2,089 lb CO_2/MW net which is less than the corrected revised standard. Just comparing the proposed CO_2 corrected to gross limit, which is the most efficient load bin, to the proposed standard is not sufficient in justifying the proposed weighted average concept with the unit degradation factor applied. An effective weighted average standard was projected for all Load Bin standards for year 2046 using operating hours by bin from 2019. Two effective weighted average standards were determined, one based on compliance with the all the load bin, including LB-0, and one with Load Bins 1 through 5 (excluding LB-0). The weighted average with LB-0 included is 2,120 lb CO_2/MWh – net, which is slightly above the proposed revised NSPS standard. The NSPS would include all emissions even emissions during startup and shutdown events. The weighted average without LB-0 is 2,100 lb CO_2/MWh – net, which is slightly less than the revised NSPS standard.

The writer has concluded that the proposed unit degradation adjustment factor should be capped at year 2046. Even though the proposed load bin standards with the weighted average fall in line with the NSPS current standard and with the proposed revised NSPS in year 2046 with the degradation factor applied, the writer does not recommend setting or using the NSPS standards in lieu of the proposed weighted average. The intent of Subpart UUUUa is to be constraining and reasonable today and into the future.

When looking at unit degradation over time, fleet performance is a key indicator of what may be expected in terms of rate of decay, and in turn, CO_2 and heat rate performance degradation. While there are many factors that can influence this degradation, two critical issues are mechanical and thermal stress and corresponding decreased unit efficiency. These may be recovered in part through maintenance activities and repair/replacement of critical systems. Another factor that greatly influences unit degradation is the Capacity Factor (CF) of the unit. As units shift from traditional base-loaded operation to increased load swings, lower steady state loads, and are operated as peaking units (many startup/shutdown events), the lower efficiency inherent in units (as demonstrated by each units unique "Heat Rate Curve") at these lower loads and changing loads, will appear as degraded performance. While it may seem that capacity factor influence may be readily filtered out from the unit degradation due to thermal and physical stresses and associated inefficiencies, it actually cannot. Increased SUSD operations, more and more radical load shifts, and increased operation at lower loads all increase physical stress, fatigue, creep, corrosion, and wear thus causing unit degradation above and beyond what may be accounted for in the observed unit efficiency reductions when operating in lower load bins.

Performance recovery after major outage work has been predicted for the Longview unit, and is reflected in the degradation/recovery rate. These outages will occur in future years and while some level of performance enhancement is expected, it may not be analytically quantified at this time due to a lack of data. It does need to be noted that not all outage/maintenance work will sufficiently recover all damage as there are practical physical and economic limits to repair and replacements at every overhaul cycle.

Based on the above, and the degradation demonstration both for Longview as well as the appropriate fleet data, CF cannot and should not be fully removed from the degradation rate. An appropriate rate has been determined and presented which accurately reflects the unit operation into the future as it ages and is supported by the included fleet performance data.

After reviewing the supporting information and justification LVP provided, the West Virginia DEP concurs with the company's recommendation. The data reviewed for the analysis shown in the charts provided in this section are from 15 coal-fired supercritical steam turbines operating in the PJM interchange over 25 years. The cumulative fleet degradation analysis compared the average fleet heat rate (Btu/kWh) in 2019 to the average fleet heat rate (Btu/kWh) in 1994.

There is a point in the degradation rate (decay curve) of a new unit where the rate of decay will slow down. Based on Black and Veatch experience of the efficiency of coal fired power plants, Black and Vetch would anticipate this change in the rate of decay to occur around 20 to 25 years of age.

The U.S. EPA has proposed a revised carbon dioxide standard for combined cycle combustion turbines and EGUs.[15] The West Virginia DAQ looked to the U.S. EPA's proposed standard for guidance in determining the time frame for allowing the standard to be adjusted to account for the rate of decay. The proposed

[15] Federal Register 83 FR 65424, Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, December 20, 2018, Table 1 – Summary of BSER and Proposed Standards for Affected Sources, Page 65427.

revised standard that would be applicable to LVP is 1,900 lbs of CO_2 per MWh gross. The U.S. EPA acknowledged that this standard should adequately account for degradation of the unit.[16]

To compare this proposed revised standard with LVP's proposed standard, the proposed revised standard was corrected to a net basis by dividing the historical difference between gross verses net of 0.9, which equates to a net generation based value of 2,111 lbs/MWh net. The 0.9 is LVP historical ratio of gross to net generation.[17]

The projected LB- 5 standard is 2,089 lbs CO_2/MWh net which is less than the corrected revised standard. Just comparing the proposed CO_2 corrected to gross limit, which is the most efficient load bin, to the proposed standard is not sufficient in justifying the proposed weighted average concept with the unit degradation factor applied. An effective weighted average standard was projected for all load bin standards for year 2046 using operating hours by bin from 2019. Two effective weighted average standards were determined, one based on compliance with all load bins, including LB-0, and one with load bins 1 through 5 (excluding LB-0). The weighted average with LB-0 included is 2,120 lbs CO_2/MWh – net, which is slightly above the proposed revised NSPS standard. The NSPS would consist of all emissions including during startup and shutdown events. The weighted average without LB-0 is 2,100 lbs CO_2/MWh – net, which is slightly less than the revised NSPS standard.

Based on the discussion above, the conclusion is to cap the unit degradation adjustment factor at year 2046.

The West Virginia DAQ utilized the U.S. EPA NEEDS Database[18] to develop a list of newer coal-fired EGUs (identified as commencing commercial operations, or coming online, after the year 2000) with a design electrical output capacity greater than 500 MWe that are combusting steam coal and that have a listed heat rate (HR), or thermal efficiency, within the range the U.S. EPA categorized as best preforming units in the ACE Rule. These EGUs historically combusted either bituminous coal, subbituminous coal, refined coal, or a bituminous coal and natural gas mix. In the Regulatory Impact Analysis (RIA) to the ACE Rule, the U.S. EPA identified the most efficient EGUs as Group 1 with a HR range of ≤ 9,773 British thermal units heat input per kilowatt-hour electrical energy output (Btu/kWh)[19]. The top three performing units taken from the NEEDS database are illustrated in Table C-6 below, met the chosen criteria, and were further evaluated.

[16] 83 Fed. Reg. 65450 (December 20, 2018).
[17] Permit Application File R13-3495, June 26, 2020, LVP Generation and OPM Heat Rates 2020-06-26.xlxs.
[18] U.S. EPA, National Electric Energy Data System (NEEDS) v6, October 5, 2020, https://www.epa.gov/sites/production/files/2020-10/needs_v620_10-05-20_0.xlsx.
[19] U.S. EPA, Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, EPA-452/R-19-003, June 2019.

Table C-6. Newer Top Three Best Performing Coal-Fired EGUs >500 MWe, Sorted by Historical Avg. Total Heat Rate.

Facility Name	State	NEEDSEGU Unit ID	CAMD EGU Unit ID	Capacity (MWe)	Historical Average Total Heat Rate (Btu/kWh)	Online Year
Longview Power Plant	WV	UHA01	90398	700	8,904	2011
James E. Rogers Energy Complex	NC	6	90414	844	9,090	2012
John W. Turk Jr Power Plant	AR	B1	90325	609	9,102	2012

The DAQ downloaded hourly emissions, operating data, gross electrical generation, heat input, and the monitoring plans for these units from CAMD using the EPA Field Audit Checklist Tool (FACT)[20]. The hourly data was sorted into five operating load bins based on the upper and lower bounds listed for each respective unit's monitoring plan filed with CAMD. Other than LVP, the data that was analyzed further was specific to the upper load bin, corresponding with the EGU's baseload operation and to LVP load bin LB-5. The heat input rate for each hour was divided by the gross electrical output of the unit for the same hour to calculate the HR for that hour. Lower heat rates indicate a more thermally efficient unit and thus less CO_2 emissions per unit of gross electrical output.

Additional historical operational data including fuel use types, origins, quality, and quantity was then downloaded from the United States Department of Energy's Energy Information Administration (EIA)[21] website and analyzed so that similar units could be accurately compared. Some units varied in fuel type while others burned a more consistent fuel composition. West Virginia DAQ could not discern when specific fuel mixes were utilized beyond an annual resolution.

The data from LVP was analyzed for each of the operating load bins, excluding load bin LB-0. Review of the LVP graphs verified that the degradation experienced thus far is at or slightly above the proposed LVP degradation rate for each of the operating load bins identified as LB-1 through LB-5. LB-5 is the baseload load bin and the operating range where LVP most often operates. This plot can be found below in Figure C-13. Similarly, the data from the selected best performing EGUs was then plotted and best-fit linear trendlines were generated and added to observe any long-term changes in HR. A review of the plots illustrates varied historical HR over the time periods analyzed, with fluctuations within the operations of each unit. An overall positive slope of a trendline indicates degradation in thermal efficiency and an increase in HR because it demonstrates an increase in the heat input to the unit measured in Btu required to generate a unit of gross electrical generation, measured in kWh; a trendline with negative slope would be an indicator of a decreasing HR or an improvement in thermal efficiency. Trendlines were added to the plots with their respective equation; see HR plots in Figure C-14 for the James E. Rogers Energy Complex and Figure C-15 for the John W. Turk Jr Power Plant below.

The following plots demonstrate the historical heat rates of the units described in Table C-7, as well as best fit linear trend lines for each plot. The plots illustrate considerable variation in unit HR, which can be attributed to seasonal variations, fuel quality, and whether the unit operations were load following or baseload. Resolution of load following versus baseload operations were not included in the plots beyond the recognition that all plots were constructed for the highest load bins, which are typically baseload in

[20] https://www.epa.gov/airmarkets/field-audit-checklist-tool-fact.
[21] https://www.eia.gov/electricity/data/eia923/.

nature and within the operational range that most units spend the majority of their operational time. Table C-7 below summarizes HR variabilities among the selected units within each unit's respective LB-5.

Table C-7 – Heat Rate Variabilities for Selected Units for LB-5.

Facility Name	Minimum HR	Maximum HR	Average HR	Standard Deviation
Longview Power Plant	7,590	8,838	8,353	226.6
James E. Rogers Energy Complex	7,986	8,631	8,291	142.9
John W. Turk Jr Power Plant	8,163	9,263	8,659	288.6

West Virginia DAQ concluded that the proposed HR degradation rate for LVP written into Permit R13-3495 is reasonable because it is consistent with the slope of the trendline matching historical data. LVP's degradation trendline is also similar to the James E Rogers and John W Turk comparison units as illustrated in the figures below.

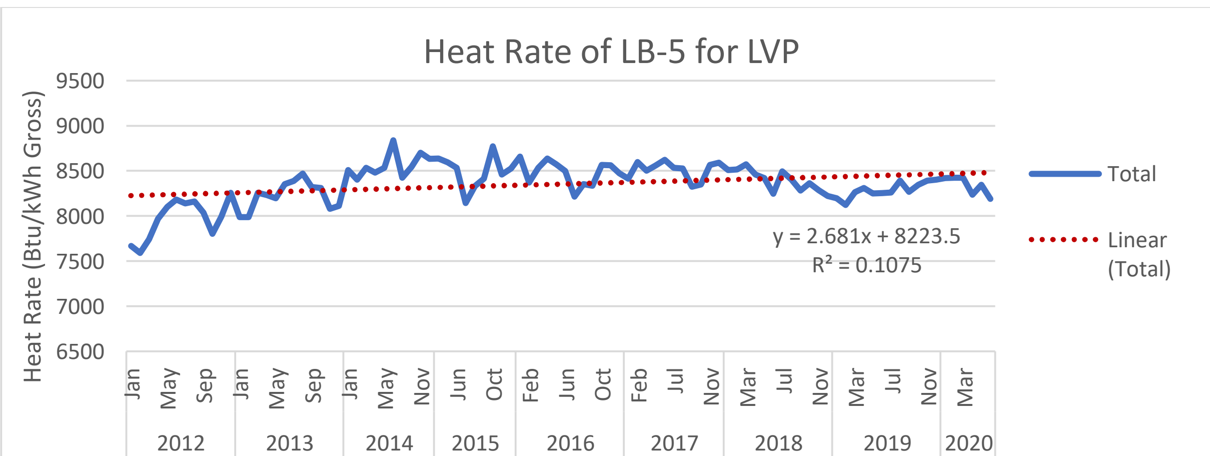

Figure C-13. Historical Heat Rates of LB-5 for LVP.

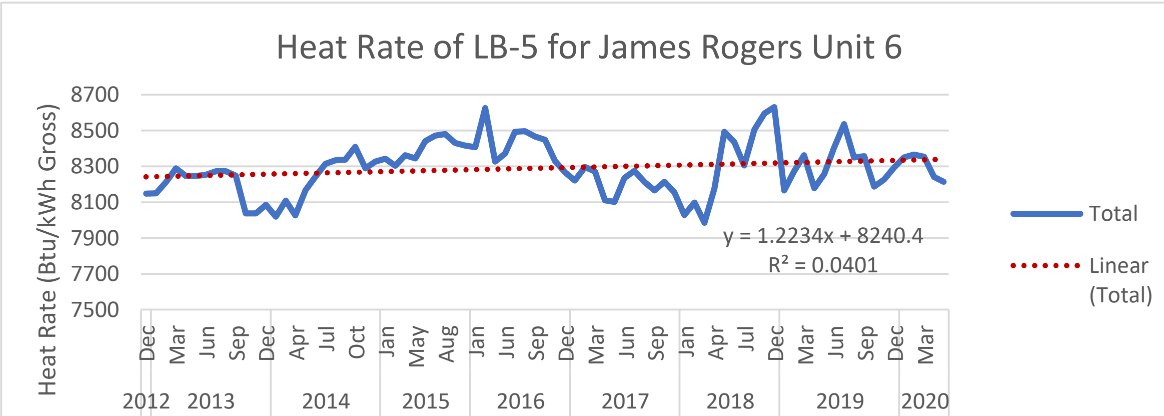

Figure C-14. Historical Heat Rates of LB-5 for James Rogers Unit 6.

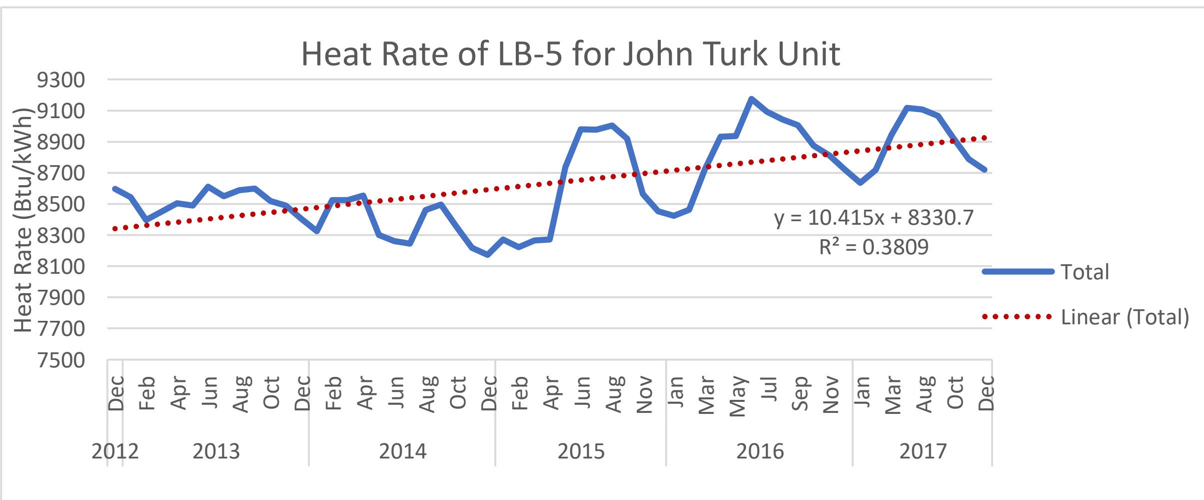

Figure C-15. Historical Heat Rates of LB-5 for John W. Turk.

In conclusion, LVP recommended a 0.4% degradation rate annually with 0.7% recovery rate every five years which is supported by historical data from the peer group and based on the demonstration provided in this section, West Virginia concurs.

Coal Adjustment Factor (CAF)

Condition 4.1.1.d of Permit R13-3495 specifies the circumstances by which a coal adjustment factor (CAF) would apply to the standards of performance. The CAF is the ratio of future CO_2 emissions divided by the baseline CO_2 emissions as determined in accordance with Condition 4.3.1 of Permit R13-3495. The CAF would only be applicable when LVP requires a switch in fuel supplier that results in a different source of coal (coal from a different coal seam with its unique properties) that LVP has determined will have an impact on the carbon dioxide emissions. Changes (variability) of measured coal properties from the same source of coal monthly does not constitute a CAF.

The CAF, not to exceed 3.0% for each instance for which it is determined, increases or decreases the Level 1 and Level 2 CO_2 limits based on the calculated ratio as described above. If a CAF is applied, any subsequent required fuel switch that the permittee has determined has an impact on the carbon dioxide emissions (whether an increase or decrease) shall follow the aforementioned requirements and testing using the most recent previously adjusted CO_2 emissions and coal supply as the baseline to develop a new CAF ratio.

The CAF addresses the future and real possibility that LVP may require a change from its current coal supply. Each coal seam has unique physical properties that could impact unit operation. Fuels with a higher hydrocarbon content have a higher heating content and would provide a higher heat rate and generate a lower CO_2 emission rate, whereas fuels with a higher sulfur content require the use of more lime in the flue-gas desulfurization (FGD) system (scrubber) which increases the CO_2 emission rate. Carbon dioxide is generated during a reaction that occurs in the scrubber to lower the sulfur dioxide (SO_2) emissions and to comply with the SO_2 emission limit.

Should a significant fuel change be warranted at the discretion of the company or as a result of a supplier change and/or issue, and LVP must undergo a fuel change, the CO_2 standard of performance would be re-evaluated and potentially adjusted in the event a future fuel change would affect the established standard of performance established in permit R13-3495. LVP identified twelve parameters and trigger levels for each of these parameters that could potentially change due to a fuel change and could affect heat rate and/or CO_2 performance. The fuel characteristics identified are: heating value expressed as Btu/lb, sulfur content, ash content, moisture content, chlorine content, nitrogen content, hardgrove grindability index (hgi), initial deformation (reducing), softening (reducing), initial deformation (oxidizing), softening (oxidizing), and size. Two of these characteristics affect CO_2 emissions directly, while the other ten characteristics affect combustion that will influence the CO_2 emissions.

In the event of a significant fuel change, LVP would notify the West Virginia DAQ of the change, as well as provide analytical data supporting the need for a re-evaluation of the CO_2 standard and abide by the CAF provisions provided in conditions 4.1.1.d and 4.3.1 of Permit R13-3495.

Fuel characteristics have substantial influence over the heat rate and CO_2 performance and are fundamental to unit performance. Minor changes in a variety of characteristics can directly influence not only combustion performance, but also increased auxiliary loads based on additional pollution control equipment needs. Increased CO_2 emission rate and heat rate may be solely caused by the change, rather than a change in unit efficiency. Coal characteristics from a specific seam are relatively consistent although these characteristics do materially vary. Changing sources of fuel that are sourced even from the same seam may be significant enough to make a relevant difference in unit efficiency and thus compliance.

The complexities of how fuel is utilized in the SB1 unit encompass significant multi-variables and complex interactions that do not lend themselves to formulaic conclusions. It is imperative that fuel be considered not only when setting the standards, but as a catalyst for review when the fuel source changes either voluntarily or forced. Due to significant instability in the current coal supply chain, coal-fired units cannot count on continuing to receive the same coal they may have burned during the sample period. Therefore, the ability to trigger a reassessment of the CO_2 standard of performance based on fuel change is critical to the economic health of all coal-fired units as in the event a current fuel supplier ceased operation, and no equivalent fuel could be obtained, units may be forced to shut down if the alternative fuels would not allow compliance with the in-effect standard of performance.

Thermal power plant operations costs are significantly dominated by fuel costs, which typically represent 70 to 80% of the total cost of operations. Inherent in the fuel cost are the cost of fuel production, transportation, and the conversion (converting the chemical energy into electrical energy – unit heat rate) efficiency. Additionally, power plants are designed to consume fuels within a specific range of the various fuel characteristics and thus have limits as to what can be burnt. An overriding fact of fuel production/supply especially with coal is that the economics of extraction and transportation can change significantly with time, geologic conditions, broader economic conditions, government policies and overall thermal coal production volumes. From these factors it is critical for each facility to maintain viable fuel resources that fit into its specific design parameters as controlling fuel cost becomes a key driver to the overall cost effectiveness of producing affordable electric power. The concept of accounting for fuel characteristics is a long-established approach in the development of emission standards for power plants[22].

Prior to developing the CAF requirements identified in Permit R13-3495, LVP and the West Virginia DEP along with the assistance from the U.S. EPA, identified alternative options. One potential option for a fuel adjustment factor that was explored was the utilization of an equation in Appendix G of 40 C.F.R. Part 75 that plays a role in how CO_2 CEMS data can be adjusted based on the carbon content of the fuel. Appendix G contains procedures for determining CO_2 mass emissions from coal fired EGUs. After extensive evaluation of this option, LVP concluded that the Appendix G equation could not be validated as an appropriate CAF either using past or current fuels burned at LVP. The equation is too simplistic and does not adequately model all the factors in determining unit level CO_2 emissions at the necessary level of accuracy. CO_2 emission levels predicted by the model varied from measured CO_2 levels by approximately +/ 10% on a monthly basis. This is too much variance for determining compliance with the CO_2 limits established as condition 4.1.1 of Permit R13-3495.

The procedures in Appendix G of 40 C.F.R. Part 75 would only account the CO_2 emissions from the carbon content in the fuel and additional CO_2 generated from the scrubber(s) to control sulfur dioxide. These procedures would not account for the changes in auxiliary load due to the fuel, which is critical for LVP to determine compliance of the SB1 unit with a net generation-based standard. The equation approach in Appendix G of 40 C.F.R. Part 75 in predicting CO_2 performance was determined not to be feasible.

There are third party software programs that predict EGU performance based upon actual design features and fuel quality that produce a more comprehensive outcome. These programs require subscription fees and only predict the unit's performance based upon difference in fuel quality and therefore were not selected.

LVP suggested conducting two test burns – one to establish a baseline of the fuel current to the existing standard and a second to establish the CO_2 emissions for the new source of fuel. In this proposal, LVP suggested using the average plus 2 x standard deviation approach. However, this proposed process will not yield enough high-quality emission data for the standard deviation to be meaningful. There needs to be

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[22] See, e.g., National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units.77 Fed. Reg. 9,304, 9367 (Feb. 16, 2012) (codified at 40 C.F.R.§ 63.9990)(Mercury and Air Toxic Standard (MATS) Subcategorization of fuel ranks).

enough data to be processed in a meaningful fashion so that the peaks and valleys in the data can be minimized. Instead, the DAQ believes using the average CO_2 rate of the most efficient load bin from both tests could yield a representative ratio of the two tests to adjust the standard. Simply using a test burn of the future fuel would not be adequate.

The testing requirements to satisfy the CAF requirements in permit condition 4.1.1.d are specified in condition 4.3.1 of Permit R13-3495 and requires the testing to be conducted by an independent third-party organization. LVP must utilize an independent third-party organization to oversee the testing, tuning of the unit on the new fuel source and development of the ratio.

West Virginia believes using the average CO_2 rate of the most efficient load bin from one test to establish a baseline of the current fuel and one test to establish the CO_2 emissions from the new source of fuel will yield a representative ratio of the two tests to adjust the standard. Simply using a test burn of the future fuel would not be adequate. The baseline test would eliminate the need to develop some sort of actual degradation adjustment factor or function to account for the change in actual degradation versus the applied degradation rate under the UDAF. By conducting both tests within short time frames (6 weeks), the results of both tests should see the effects of relatively the same level of degradation.

The purpose of this CAF is to adjust the standard based on the effect of the coal (fuel) quality with respect to the unit. The key to making this CAF functional is for the ratio to be applied both ways (up/down – accounting for both worse and better fuel quality). Second, the unit must achieve and sustain a state to efficiently burn the new fuel in a timely and optimized fashion. Third, the collected emissions data must be sufficient in quantity and quality.

To ensure that the CAF does not radically change the standard, a cap needed to be developed and is established as 3.0% in condition 4.1.1.d of Permit R13-3495. Looking at the margin of compliance of the Weighted Average CO_2 standard versus historical CO_2 excluding emissions occurring during Load Bin 0 in Figure C-16 below, the margin is consistent except during the unit's initial startup. The annual average margin of compliance is 3.06% over this period.

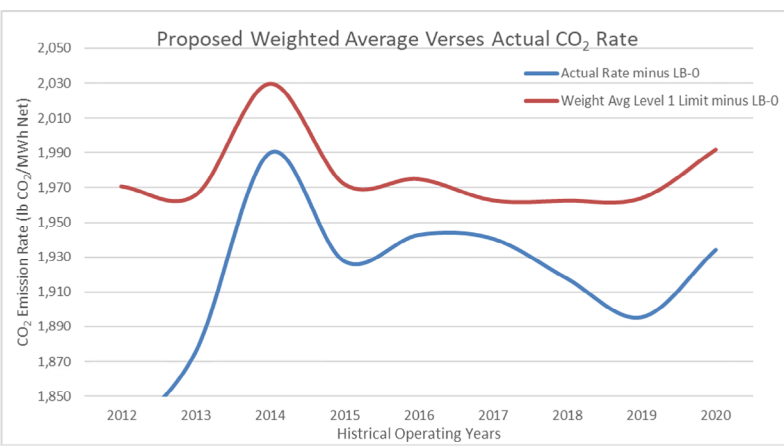

Figure C-16. Proposed Weighted Average Versus Actual CO_2 Rate

This 3.0% cap would therefore indirectly limit the CAF to a reasonable margin of compliance from the baseline emission rate. The main reason for establishing a cap is minimize the extent that the applicant could gain compliance margin and not continue to invest in HRI to maintain compliance with the CO_2 standard. The CAF or the cap does not prevent LVP from requesting a new standard of performance (new CO_2 standard), which would require an update or modification to Permit R13-3495 and West Virginia to submit a revised State Plan to be approved by the U.S. EPA Administrator.

If the CAF was only applied if the new fuel source increased CO_2 emissions, then a source could keep shopping for a new fuel source that increases the CO_2 standard to get a desired standard that the unit can achieve without making any changes to improve the unit's heat rate or minimize CO_2 emissions.

To ensure that the ratio is based on sufficient and quality emissions data, Permit R13-3495 stipulates that each test run must have at least 151 operating hours in LB- 5, which equates to 90% of the possible hours in a week. The collected data for each test run needs to yield a standard deviation 68 lbs CO_2/MWh net or below.

The collected hourly data may have to be reduced from hours to days to improve the standard deviation to meet the acceptable level. If the data is reduced for one of the test runs, then the methods need to be applied to both test runs. Another option is to extend the testing past 7 days and shift the test period to meet the data quality requirements.

A fourth equation was developed to address periods when the CAF is applied within a compliance period. When a CAF is applied after the beginning of a compliance period, the permittee shall determine the Level 1 CO_2 weighted average and Level 2 CO_2 weighted average before the CAF and after the CAF using Equations 1 and 2 and the appropriate CO_2 limits for each of the load bins. LVP is required to use the following equation to determine the CO_2 weighted avg in lieu of Equation 3. Listed below is Equation 4 which is provided in Condition 4.4.4. of Permit R13-3495.

Equation 4.

$$CO2\ Weighted\ Avg\ =$$

$$\frac{(Level\ 1\ CO2_{WBCAF} \times \sum OPHL1_{BCAF}) + (Level\ 2\ CO2_{WBCAF} \times \sum OPHL2_{BCAF}) + (Level\ 1\ CO2_{WACAF} \times \sum OPHL1_{ACAF}) + (Level\ 2\ CO2_{WACAF} \times \sum OPHL2_{ACAF})}{\sum OPHL1_{BCAF} + \sum OPHL2_{BCAF} + \sum OPHL1_{ACAF} + \sum OPHL2_{ACAF}}$$

Where:

CO2 Weighted Avg = the weighted average of the CO_2 Limits adjusted for the compliance period when a CAF is applicable, in terms of lb of CO_2 per MWh of net generation.

Level 1 $CO2_{WBCAF}$= Level 1 CO_2 weighted average limit calculated using Equation 1 of the time period before the CAF was taken into effect.

$\sum OPHL1_{BCAF}$ = The sum of the operating hours of the unit in Level 1 before the CAF was taken into effect.

Level 2 $CO2_{WBCAF}$ = Level 2 CO_2 weighted average limit calculated using Equation 2 of the time period before the CAF was taken into effect.

$\sum$OPHL2BCAF = The sum of the operating hours of the unit in Level 2 before the CAF was taken into effect.

Level 1 $CO2_{WACAF}$ = Level 1 CO_2 weighted average limit calculated using Equation 1 of the time period after the CAF was taken into effect.

$\sum$OPHL1ACAF = The sum of the operating hours of the unit in Level 1 after the CAF was taken into effect.

Level 2 $CO2_{WACAF}$ = Level 1 CO_2 weighted average limit calculated using Equation 2 of the time period after the CAF was taken into effect.

$\sum OPHL2_{ACAF}$ = The sum of the operating hours of the unit in Level 2 after the CAF was taken into effect.

Please refer to Appendix F for a discussion regarding data used to develop the 3 percent cap.

Stringency with 40 C.F.R. Part 60, Subpart TTTT

Condition 4.4.4 of Permit R13-3495 stipulates LVP shall comply with the less stringent of either the weighted average of the load bin standard of performance described previously or the standard of performance established for new stationary sources under 40 C.F.R. 60, Subpart TTTT, *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units.* The justification for this is that LVP is an existing EGU that should not be held to standard of performance that is more stringent than any standard established for new stationary sources. West Virginia air quality legislative rules and programs, such as this State Plan, cannot be more stringent that its federal counterpart[23].

Compliance Determination

Condition 4.1.1 of Permit R13-3495 states:

> Except for periods of operation in Load Bin 0, carbon dioxide (CO_2) emissions released to the atmosphere from Emission Point EA1 shall not exceed the limit calculated using Equations 3 or 4 in section 4.4 of this permit. Calculated limits shall include all carbon dioxide emissions from the source and compliance shall be on a calendar-year basis. The following limits for each respective load bin shall be utilized as appropriate in Equations 1 and 2 in section 4.4. of this permit for determination of the Level 1 and Level 2 CO_2 Weighted Average Limits. The Level 1 Limits defined in 4.1.1.a. of this condition, shall apply at all times unless the permittee satisfies the requirements of 4.1.1.b of this condition, in which the Level 2 Limits go into effect in accordance with the timing as stipulated in 4.1.1.b. of this condition. While operating in Load Bin 0, the CO_2 emissions released to the atmosphere from Emission Point EA1 shall not exceed the limit in 4.1.1.a.i. This limit shall include all carbon dioxide emissions from the source and compliance shall be on a calendar-year basis.

[23] W. Va. Code § 22-5-4(a)(4).

Compliance with the LB-0 CO_2 emissions rate limit is specified in condition 4.4.5 which regarding LB-0 states:

> The permittee shall demonstrate compliance with the CO_2 Load Bin 0 Limit in Condition 4.1.1a.1.by summing the hourly CO_2 emissions that occurred when the unit was operating in Load Bin 0 during the compliance period divided by the sum of the gross generation from the unit in Load Bin 0 during the compliance period.

Determining compliance with the limit for LB-0 in accordance with the above calculation was decided upon because of the small amount of time LVP spends operating at less than it minimum stable load and because the emission limit for this load bin is based on terms of gross electric generation. Demonstration for this load bin therefore must be calculated independently from the other load bins.

Determining compliance with a CO_2 Weighted Average based on the amount of time spent operating in load bins LB-1 through LB-5 in accordance with the limit calculated using Equation 3 or 4 as appropriate based on condition 4.4.4 of Permit R13-3495 was decided upon for the following reasons. As previously discussed, the amount of time spent operating in load bins LB1 through LB-4 combined is less than 10% of total operating hours over the entire baseline period. The amount of time spent operating in each of these individual load bins is as low as 1.2% over the baseline period for LB-1. Based on the information provided by LVP regarding future operating characteristics, the amount of operating time anticipated to be spent operating outside of LB-5 is expected to be very small into the foreseeable future. Given the realistic potential for such a small amount of data anticipated to be collected for load bins LB-1 through LB-4, West Virginia decided the best approach was to calculate a weighted average limit based on the amount of time LVP spends in each of the respective load bins and to demonstrate compliance against said weighted limit based on the standards developed for each of the respective load bins.

Consideration was given to compliance for the standard of performance for each of the load bins without consideration of a weighted average, but that option was not selected for several reasons:

1. Since SB1 has primarily operated as a base-loaded unit (e.g. 90% operation in LB-5) during the baseline years, there are not sufficient data points to determine a specific standard of performance for each individual load bin that would generate a high confidence level in the lower load bins LB-1 through LB-4. As illustrated in the cumulative distribution plots below (Figures C-17 through 21), the variability of the data steadily decreases as gross output increases.

2. Table C-8 below is a summary of the count of the number of hourly data points from each load bin during the baseline period used to develop the standard. Although more data points became available for evaluation during the 2Q 2020 because more time was spent operating in LB-4, the reader can observe the small number of data points in comparison with LB-5. The same holds true for the lower bins LB-1 through LB-3. Therefore, although there was sufficient data to establish a statistically significant standard for these load bins, West Virginia did not think there was sufficient data to demonstrate compliance with the actual load bin limits on a stand-alone basis.

Table C-8. Load Bin Data Point Counts.

Load Bin	Total Data Points
LB-1	405
LB-2	127
LB-3	463
LB-4	256
LB-5	29,457

3. By developing a standard of performance based on a weighted average of the operating time in the different load bins, more operational flexibility will be allowed with an increase of the confidence level for compliance while operating within all the load bins.

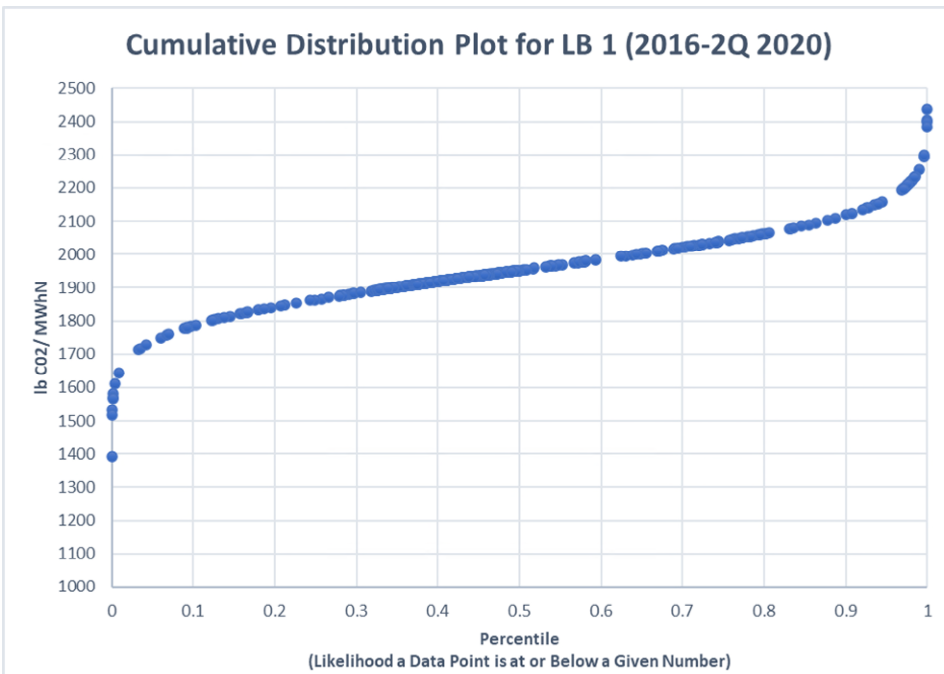

Figure C-17. Cumulative Distribution Plot for LB-1 (2016 – 2Q 2020)

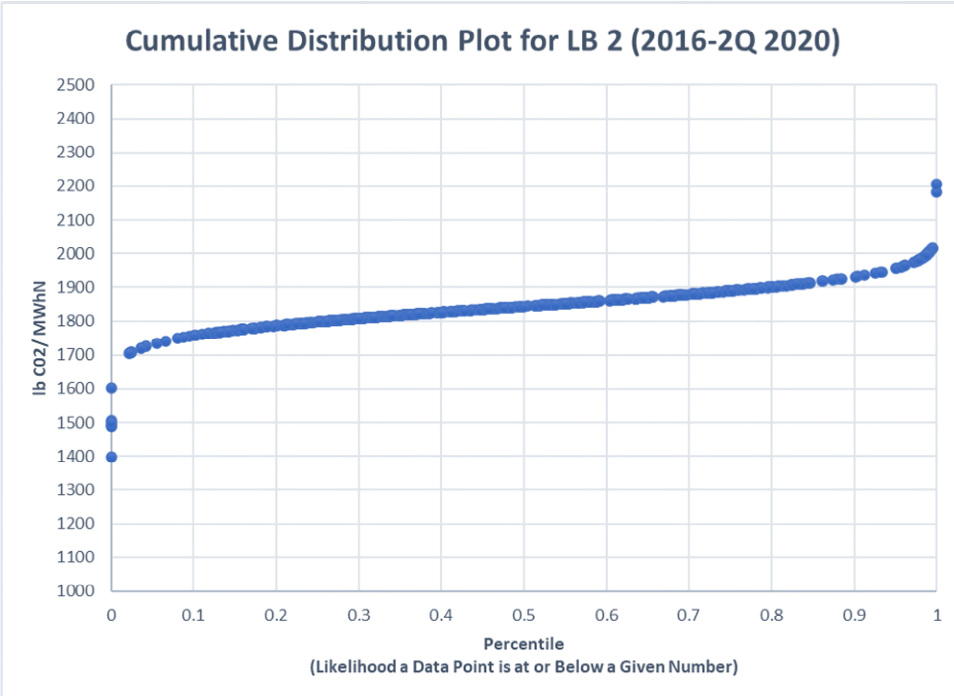

Figure C-18. Cumulative Distribution Plot for LB-2 (2016 – 2Q 2020)

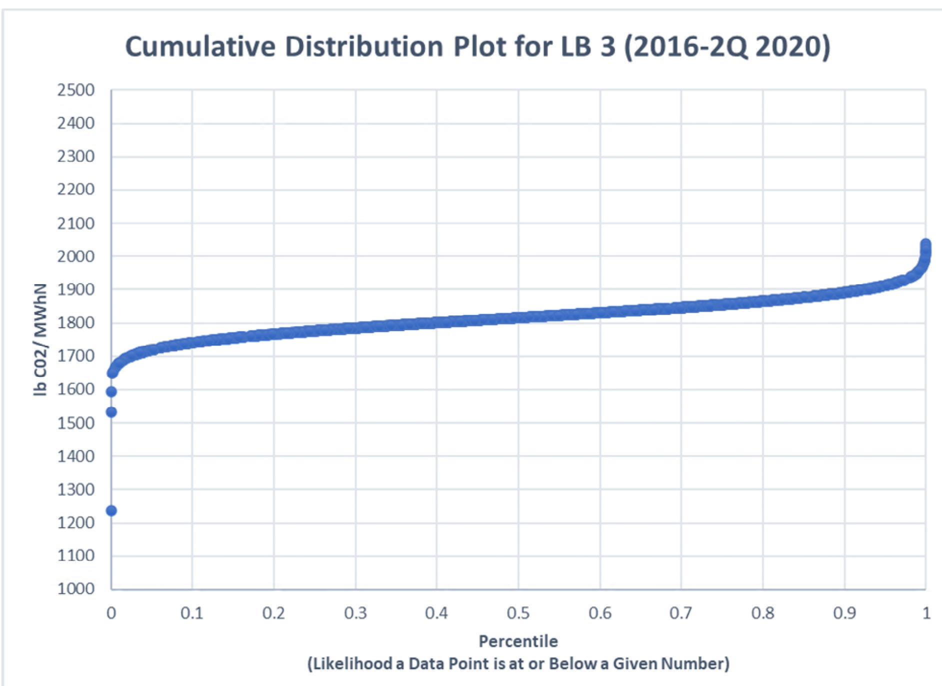

Figure C-19. Cumulative Distribution Plot for LB-3 (2016 – 2Q 2020)

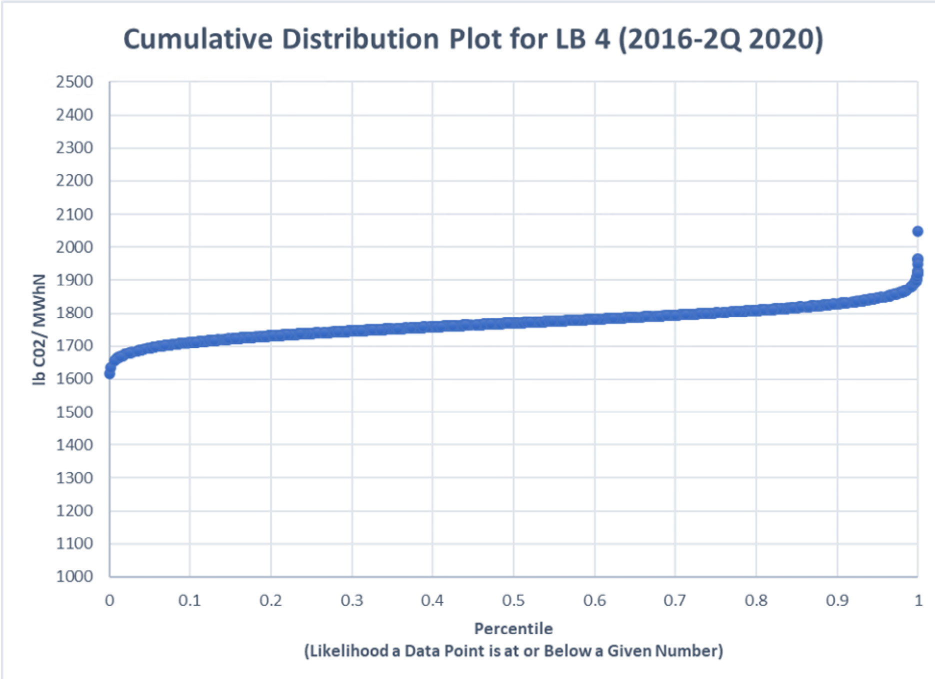

Figure C-20. Cumulative Distribution Plot for LB-4 (2016 – 2Q 2020)

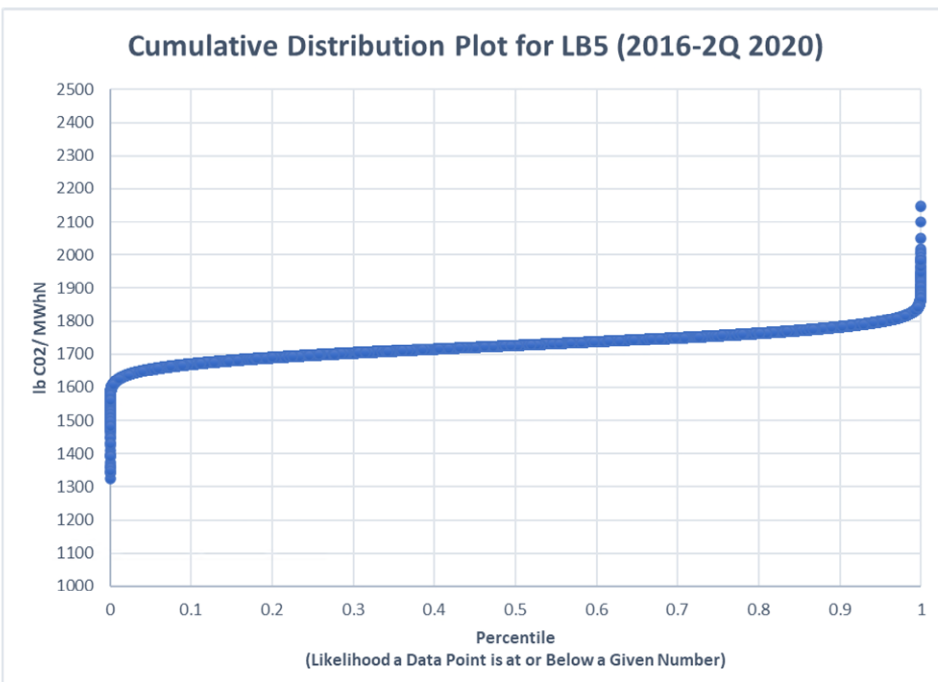

Figure C-21. Cumulative Distribution Plot for LB-5 (2016 – 2Q 2020)

Compliance Period

The compliance period established for LVP in condition 4.4.5 of Permit R13-3495 is on a 12-month annual calendar basis with the initial compliance period beginning on January 1, 2021 and ending December 31, 2021. Subsequent compliance periods follow thereafter. The compliance demonstration is required no later than March 1 following the end of the compliance period.

Strong consideration was given to determining compliance on a 12-month rolling average basis; however, given the complexity of the proposed standards of performance under condition 4.1.1 of Permit R13-3495, for practical reasons it was decided to simplify the compliance demonstration. Timing of the application of the UDAF, calculations for the weighted average limit based on the operating time spent in each of the load bins, along with the requirement for West Virginia to provide an annual compliance report to the U.S. EPA are better suited to an annual compliance period based on an calendar year basis.

While establishing the standards of performance for the load bins, DAQ determined there was insufficient data available on a calendar year basis. The use of data on an calendar year basis would result in only one data point for each year from 2016 – 2019, and a 2020 data point would not have been included as the year was incomplete at the time of the analysis. The use of the 12-month rolling average to develop the standards of performance allowed for a 12-month period; however, it also allowed for significantly more data points to establish the load bin standards. By analyzing the data on an hourly basis, DAQ was able to maximize data resolution and eliminate shorter periods which would have disproportionate influence on the data analysis and limit development. West Virginia considers the decision to demonstrate compliance with the standards on a 12-month calendar basis to be one of practicality, given that both the establishment of the standards and compliance are both based on a 12-month basis. Table C-9 below shows the 2019 rolling weighted average CO_2 emission limit in the second column and the actual 2019 monthly CO_2 emissions in the third column with the % difference in the fourth column. The difference between the 12-month rolling average for this time frame and the 12-month annual emission rate for this time frame is 0.11%. The difference between the 12-month calendar basis and the 12-month rolling average basis as demonstrated below is not significant.

Table C-9. LVP 2019 Weighted Average CO_2 Emission Limit and Actual Monthly CO_2 Emissions

2019 Month	Level 1 CO2 Weighted Avg Limit	Level 1 CO2 Rate (lb/MWh - Net)	% Difference of the Limit vs Actual Rate
Jan	1,964	1,872	4.68%
Feb	1,958	1,852	5.43%
Mar	1,961	1,886	3.83%
Apr	1,959	1,895	3.25%
May	1,979	1,887	4.67%
Jun	1,981	1,903	3.94%
Jul	1,962	1,886	3.87%
Aug	1,968	1,923	2.32%
Sep	1,963	1,889	3.80%
Oct	1,964	1,908	2.86%
Nov	1,961	1,916	2.30%
Dec	1,960	1,918	2.16%
Weighted Averages	**1,964**	**1,895**	**3.48%**
		Avg of 12 Months % Difference Actual Emissions	3.59%
		Difference of the 12 Month Rolling vs Annual Emission Rate	0.11%

Additionally, LVP is subject to interstate transport regulations (i.e. Acid Rain Program, CSAPR) that require sources to maintain allowances for their annual emissions of sulfur dioxide and nitrogen oxides at the end of each calendar as part of demonstrating compliance with these respective programs. Maintaining compliance of these programs on the same calendar year basis would provide consistency to both LVP and the West Virginia DAQ.

D. [60.5755a(a)(2)] DETERMINATION OF EMISSION LIMITATION ACHIEVABLE FROM APPLICATION OF HRI BSER CANDIDATE TECHNOLOGIES IN §60.5740a(a)(1) and (2):

West Virginia considered the applicability of each of the seven BSER heat rate improvement (HRI) candidate technologies and the associated degree of emission limitation achievable as provided in 40 C.F.R. §60.5740a(a)(1) and (2). The demonstration for how West Virginia considered each HRI and associated degree of emission limitation achievable in calculating each standard of performance is provided below.

As demonstrated in this analysis, there are no additional BSER upgrades or improvements available that can be applied at LVP's unit SB1. In calculating the standard of performance, the level of emission reduction achievable through the application of BSER at LVP's unit SB1, which is zero, was subtracted from the baseline.

The conclusion that there is no potential for further HRI opportunity by applying BSER to LVP is consistent with the assumption that the U.S. EPA provided in the Regulatory Impact Analysis (RIA) where it identified four groups of EGUs based on heat rate performance from most efficient to least efficient based on the National Electric Energy Data System (NEEDS) database v6. The U.S. EPA states "Group 1 represents the most efficient units in the fleet. Those units are assumed to have little to no potential for further HRI applying the BSER technologies.[24]" Group 1 was defined in Table 1-1 of the RIA as EGUs having a heat rate range of less than or equal to 9,773 But/kWh[25]. The heat rate for LVP from the NEEDS_v6 database is 9,039 Btu/kWh[26] and therefore is one of the Group 1 most efficient coal fired EGUs in the country.

LVP employed the best available technology (BAT) as part of the original design when it was commissioned in 2011. As further described under the HRI analysis for each of the BSER candidate technologies, the cost to rebuild or replace existing state-of-the art equipment that has been in operation less than 10 years would be unreasonable, especially when considering that LVP is currently one of the most efficient coal-fired EGUs in the United States.

As discussed in further detail below, LVP considered each of the BSER technologies and practices specifically enumerated in the ACE rule in the permit application submitted for Permit R13-3495. West Virginia DEP thoroughly reviewed the LVP analysis and documented the analysis in the corresponding Engineering Evaluation to Permit R13-3495. LVP has already fully implemented six of the seven BSER technologies and practices. The only BSER technology not currently installed is the use of variable frequency drives (VFD) on some facility equipment; however, the technology currently being utilized by LVP is equivalent to or better than VFDs, including variable vane fans. In the limited instances in which VFDs could be added and provide some HRI, such as on condensate pumps, the expected cost of $750,000 to $1,200,000 for such a project compared with the expected trivial HRI of 1 - 3 Btu/kwh benefit in return demonstrates they would not be cost effective projects and would take longer than the life of the facility for a return on investment. Thus, LVP and the West Virginia DEP were unable to identify any further HRI from the BSER candidate technologies listed in the ACE rule.

The U.S. EPA has stated that "[a] prime example of an 'other factor' [precluding a heat rate improvement] is ruling out the reapplication of a candidate technology. The U.S. EPA expects this to be a part of many state plans." 84 Fed. Reg. at 32,554. The U.S. EPA has also noted that "[a]pplying a specific candidate technology at a designated facility can be a unit-by-unit determination that weighs the value of both the cost of installation and the CO_2 reductions." LVP has already integrated the BSER technologies specified in the ACE rule (or in the case of VFDs an alternative providing even greater HRI) into the design, construction, and operation of the plant, which have successfully achieved both high efficiency and low CO_2 emissions, and with any further trivial potential HRI not being cost effective, there are no additional HRI improvements that can be applied at the unit.

The LVP Power Heat Rate Improvement analysis (summarized in Table C-10 below) is based on the U.S. EPA guidance of best available technology (BAT) and the potential heat rate improvements (HRI) based on a unit greater than 500 MW provided in Table 1 to 40 C.F.R. §60.5740a(a)(2)(i). In LVP's case, all the technical equipment solutions are part of the base design of the facility except for Neural

[24] Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, Section 1.6.2, Page 1-12.
[25] *Ibid.*, Page 1-13.
[26] NEEDS_v6_06-30-2020, available on-line at https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6.

Network/Intelligent Combustion and Intelligent Sootblowing, which were integrated after the Commercial Operating Date (COD). Intelligent Sootblowing created benefits due to reduction in reheat spray flow and improved heat transfer. Intelligent Combustion with the Neural Network allowed for a reduction in oxygen (O_2) in the boiler resulting in a heat rate benefit.

Table C-10 assumes an 8,800 Btu/kwh baseline to calculate the targeted range of potential improvement listed in the ACE rule[27]. Additional columns were added to list the LVP results for both the post COD improvements and the technologies inherent in the base facility design. It should be noted that for developing the range of potential improvement of the unit's heat rate that potential improvements were summed together. However, these HRI measures will not result in an additive efficiency upgrade in that installing HRI technologies in parallel with one another may mitigate the effects of one or more of the technologies[28].

Table C-10. Longview Power LLC Heat Rate Improvement.

HRI Measure	>500 MW		Longview Target (Btu/kWh)	
(Assuming 8,800 Btu/kwh baseline OPM[1] heat rate)	**% Min**	**% Max**	**Min**	**Max**
DCS / Neural Network / Intelligent Sootblowers	0.3	0.9	26.4	79.2
Boiler Feed Pumps	0.2	0.5	17.6	44.0
Air Heater & Duct Leakage Control	0.1	0.4	8.8	35.2
Variable Frequency Drives	0.2	1.0	17.6	88.0
Blade Path Upgrade (Steam Turbine)	1.0	2.9	88.0	255.2
Redesign / Replace Economizer	0.5	1.0	44.0	88.0
Improved Operating and Maintenance (O&M) Practices	-	2.0	-	176.0
Total Potential of all of the Heat Rate Improvements			202.4	765.6
Projected HR without BSER implementation (Btu/kWh)			8,5989,002	9,566
Change in HR (%)			2.3	8.7

OPM is Black & Veatch's On-Line Performance Monitoring System; a real-time heat-rate monitoring model.
OPM Baseline HR 8,800 Btu/kWh calculated on a lower heating value basis.

The HRI evaluation for each of the candidate technologies for possible applicability at LVP is provided below.

Neural Network / Intelligent Sootblowers

Typical sootblowing operations at most facilities are operated with pre-set sequences of sootblowers on specified timing intervals. This mode of operation can result in the erosion of tubes in some areas of the unit and excessive slagging in others. These sootblowers either use steam or compressed air. Regardless of which medium is used to clean the tubes and heat exchanger, the auxiliary load of the unit is increased which affects the overall heat rate (decreases the efficiency) of the unit during sootblowing operations.

Intelligent Sootblowing systems use sensors that measures surface temperatures or water/steam temperatures of these circuits at key locations/sections of the unit to determine the cleanliness and heat transfer performance of the heating surfaces in the unit and is programed to activate only sootblowers in

[27] 84 Fed. Reg. 32,520 (July 8, 2019).
[28] 84 Fed. Reg. 32,554 (July 8, 2019).

the location or section that the system determines need to be cleaned to restore heat transfer performance of the heating surfaces (tubes and heat exchangers) of the unit.

According to the ACE rule, a neural network means a computer model that can be used to optimize combustion conditions, steam temperatures, and air pollution at a steam generating unit.

The neural network and intelligent sootblowing technology have previously been applied to SB1. There was a neural network DCS upgrade / replacement in June of 2015. Intelligent sootblowing commenced in the fall of 2015 and intelligent combustion operations began in the fall of 2018.

The Distributed Control System (DCS) is a digital hardware/software process that takes a large number of operating data points across the plant's systems to control and adjust processes through a central control station. This initial upgrade enabled the inclusion of Intelligent Combustion and Intelligent Sootblowing in an efficient and cost-effective manner. Intelligent combustion resulted in a HRI of approximately 20 to 40 btu/kwh due to a 1% reduction in oxygen, and intelligent sootblowing resulted in a HRI of approximately 25 to 50 btu/kwh due to the ability to control the reheat spray and increase heat transfer in the boiler.

Babcox and Wilcox, the vender of LVP's intelligent sootblowing system, and LVP conducted performance testing of this sootblower system from September 2015 through May 2016. This intelligent sootblowing system reduced the gas temperatures at the platen inlet and furnace exit sections of the unit during this demonstration. The reduction in temperatures in these sections indicate that the heat transfer efficiency had increased. The improved heat transfer efficiency of the heating surfaces up stream of the reheat section allowed LVP to reduce the reheat spray flow, which is required to control the heat steam temperature. Thus, the system reduced the unit heat rate by 90 Btu/kWh.

Since LVP had already installed these HRI technologies, no further evaluation of the technical and or economic feasibility of these two HRI candidate technologies is necessary.

Boiler Feed Pumps

Boiler feed pump (BFP) technology was applied to SB1 as part of the base design of the LVP site in the original commissioning in 2011. BFPs have a Best Available Technology (BAT) variable speed hydraulic coupling to allow for efficient control and optimization of the process. LVP's unique boiler feed pump design utilizes a constant speed motor directly coupled to a condensate booster pump that provides sufficient suction head for the feedwater pump, which is in turn coupled to the same motor through a VOITH variable speed hydraulic coupling that permits precise and stepless speed control. This speed control allows the feed pump to vary flow in the same fashion as a Variable Frequency Drive (VFD) pump without the throttling losses of a constant speed pump configuration. A retrofit to a VFD is estimated to cost approximately $9.9 million and based on economics, would provide no meaningful benefit to Longview's current or expected operation. Additionally, it would require an additional motor to drive the condensate booster pump thereby negating any efficiency increases and the overall system would not gain any efficiency due to reduced throttling losses.

Because the BFP was part of the base design for efficiency, there was no HRI achieved. Pump performance will slowly degrade over time due to normal wear and tear. LVP has extensive condition and performance modeling programs, both in-house and via a third party, to ensure pumps stay reliable and on pump curves to maintain efficiency over the maintenance cycle of the pumps. A pump rebuild is designed to take a pump back to near new performance so with proper maintenance the heat rate can be maintained. There are no further upgrades or improvements available with this technology because the current pump design and operation is consistent with BAT for new installations.

LVP contracted Black & Veach to perform a limited heat rate study[29] to develop a high-level assessment report regarding four specific items including potential internals upgrades for boiler feed pumps. A copy of this report is provided as Appendix J to the State Plan. "The stated 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)." According to the report, there are three boiler feed pump trains. Regarding Boiler Feed Pump 1, the report states:

> 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.

Regarding Boiler Feed Pump 2, the report states:

> 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.

Regarding Boiler Feed Pump 3, the report states:

> 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.

The West Virginia DAQ Engineering Evaluation corresponding with Permit R13-3495 states:

> LVP had Black & Vetch (B&V) evaluated the current condition of each of the three boiler feed pumps. B&V used the pump performance curves from the original equipment manufacturer (OEM) and actual pump data from July 25, 2019 to determine if the any of the three pumps are falling off the OEM performance curve. The actual pump data for each of the three pumps indicate that actual performance of these pumps is at or lies slightly above the OEM's performance curve. This indicates that there little to no degradation has occurred on any of the boiler feed pumps. B&V concluded that no technology upgrades of the any boiler feed pump internals are not recommended as a viable method for improving the heat rate of LVP's unit.

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[29] Black & Veach "Final Longview Unit 1 Heat Rate Study"; 31 July 2020; B&V Project Number 406009; File Number 14.410.

The West Virginia DAQ permit engineer concurs with LVP's claim and B&V's recommendation that there is no viable upgrade for the boiler feed water pumps that would result in a measurable heat rate improve of the unit.

Air Heater & Duct Leakage Control

This heat rate improvement implies that a unit is equipped with a regenerative style air heater. Regenerative air heaters transfer heat indirectly by convection as a heat storage medium is periodically exposed to hot and cold flow streams. Regenerative air heaters are relatively compact and are the most widely used type of air heater in the electric utility steam generating units. The regenerative air heater most notable operating characteristic is that a small but significant amount of air leaks into the flue gas steam due to the rotary operation.

LVP use a regenerative style air heater on their unit. Their air heaters have a double seal design which can be adjust while on-line. Figure C-22 below is an illustration of LVP's adjustable seal design.

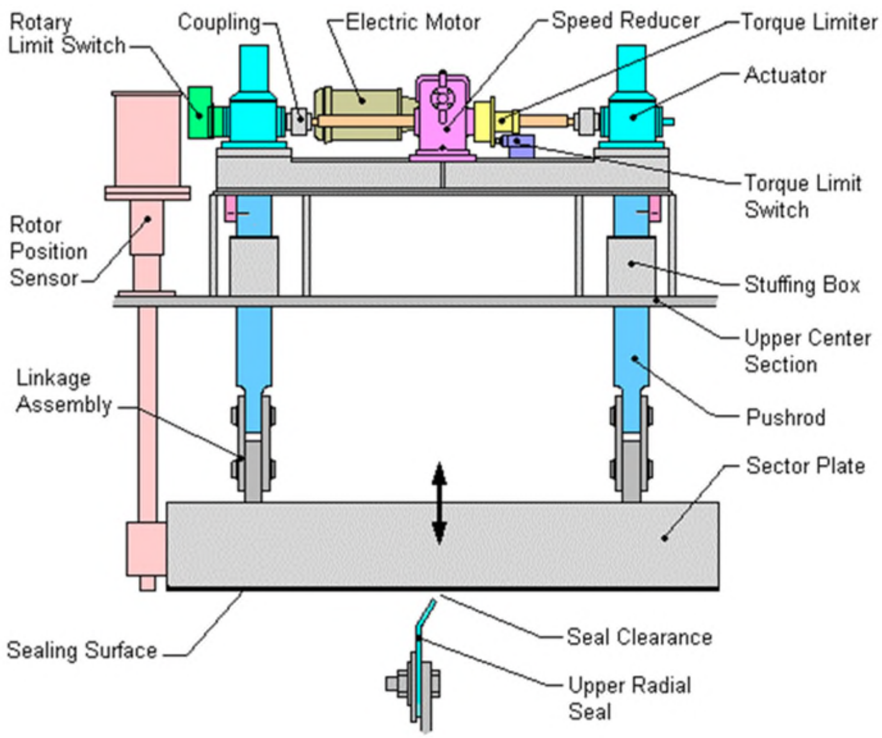

Figure C-22. Longview Power Plant Adjustable Seal Design.

West Virginia DAQ concurs with the LVP claim that their original air heater seal design meets the intent of the HRI under the ACE rule. The intent of this BSER candidate technology is to reduce leakage by replacing worn out seals, changes the seal design, and using better materials for the seals (i.e. from single to double seals, wear resistance materials, adjustable seals) all with the purpose of reducing air leakage through the seals and repairing ductwork. West Virginia DAQ therefore considers that LVP has already implemented this BSER technology.

Variable Frequency Drives (VFD)

The variable frequency drive technology has not been previously applied to the EGU because LVP's design incorporates the use of variable pitch axial fans to control the input of air and exhaust of gases (balance draft unit). The intent of using VFDs is to provide increased efficiencies for older centrifugal fans commonly used on the bulk of the country's coal fired EGU fleet. LVP, due to its recent design, makes use of the constant speed motive force but varies the pitch of the fan blades to control flow. This results in greater efficiency for the motor in a manner that is equivalent to or better than the centrifugal fan/VFD format[30]. The use of variable pitch axial flow fans results in a 0.39% to 0.53% (full load benefit only) heat rate improvement over constant speed centrifugal fans while providing for better efficiency over a wider load range. Due to this, LVP does not expect that VFD would provide any additional HRI over the application of the axial flow fans currently installed. The induced draft fans and the forced draft fans have utilized the variable blade pitch design since the original commissioning in 2011. This technology was part of the base design for efficiency. It is anticipated this will be sustained for the life of the EGU with proper maintenance. No further upgrades or improvements are available with the air/fan systems - the axial variable blade pitch fan design is the current state of the art for power plant fan systems.

VFDs may provide some heat rate improvement in selected condensate pumps should the LVP unit face a significant change in its operating regime (i.e. increased low load cycling). However, the net efficiency gain from the use of VFDs on condensate pumps (0.014% to 0.028%) is considered marginal. The marginal benefit is due to the facility being base loaded with condensate pumps design and operation being at a very efficient point on the pump curve. The investment of $750,000 - $1,250,000 is not able to be recovered in current operating conditions. The comparison of marginal HRI with considerable cost do not make it a cost effective project (poor cost/benefit). Under very specific circumstances, it is technically feasible to apply this HRI to the condensate pumps. Based on operating data and review of the pump curve, it is projected that this application of VFD technology could provide an additional 0.014% to 0.028% heat rate improvement. This percentage of HRI potential is outside the range in Table 1 to 40 C.F.R. § 60.5740a(a)(2)(i). A significant amount of the equipment at LVP already has variable technologies. Additionally, based on LVP being a base-loaded facility and condensate pumps operating at an efficient load point at full load there is not significant incremental value in this case. The HRI potential differs from the ranges in Table 1 to 40 C.F.R. § 60.5740a(a)(2)(i) due to a significant amount of equipment already equipped with BAT variable technologies. Additionally, based on LVP operating as a base-loaded facility, the condensate pumps operate at an efficient load point and as such there is not significant incremental value in this case.

The U.S. EPA developed the *Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units*[31] (RIA) as a technical support document associated with the federal ACE rule final action because it was an

[30] THE BABCOCK AND WILCOX COMPANY, STEAM/ITS GENERATION AND USE 25-19 (Gregory L. Tomei ed., 42nd ed. 2015) (noting that "[v]ariable pitch axial flow fans used in fossil power generating systems can be more efficient than equivalent centrifugal type fans" and "[s]everal major benefits observed from this figure for axial flow fans include ... [t]he areas of constant efficiency run parallel to the boiler resistance line resulting in high efficiency over a wide boiler load range ...").

[31] EPA-452/R-19-003, June 2019.

economically significant regulatory action. Section 1.5.4 of the RIA addresses VFDs on induced draft (ID) fans and on boiler feed pumps only. Discussing VFDs on ID fans, the RIA states in pertinent part:

> The increased pressure required to maintain proper flue gas flow through downstream air pollutant control equipment may require additional fan power, which can be achieved by an ID fan upgrade/replacement or an added booster fan. Generally, older power plant facilities were designed and built with centrifugal fans. . .

LVP asked Black & Veach to perform a limited heat rate study[32] to develop a high-level assessment report regarding four specific items including VFD deployment for induced draft fans and boiler feed pumps. As previously mentioned, a copy of this report is provided as Appendix J to the State Plan.

Section 3.1 of the Black & Veach report addresses VFD upgrades. The introduction to this section of the report states in part:

> 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.
>
> . . .

[32] Black & Veach “Final Longview Unit 1 Heat Rate Study”; 31 July 2020; B&V Project Number 406009; File Number 14.410.

> 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).

Section 3.1.1 of the Black & Veach report discusses the analysis of VFDs on the boiler feed pumps and concludes the heat rate improvement would be negligible at full load (782 MW gross) and 0.5% at low load (475 MW gross). The total installed capital cost is $9.9 million for three boiler feed pumps with an additional estimated annual operations & maintenance cost of $9,000. As previously mentioned in this Appendix C, the LVP operates in load bin LB-5 (full load) approximately 90% of the time. The recommendation was stated as follows:

> 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.[33]

LVP estimated that the capital cost of implementing this technology to their unit would be $12.65 per kW on a gross basis. This capital cost exceeds maximum projected cost in Sargent & Lundy, *Coal-Fired Power Plant Heat Rate Reductions, SL-009597 Final Report, January 22, 2009*[34] of $8.5 per kW adjusted to 2020 dollars from 2008. The annual operation and maintenance cost were estimated to be $9,000 for all three pumps.

The SB1 unit has operated at loads of less than 695 MW during the proposed baseline period (2016 to 2nd Quarter of 2020) for only 10% of the operating time, which does not include startup and shutdown periods (loads less than the unit's minimum load of 313 MW gross). 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.

As stated in the Engineering Evaluation corresponding to Permit R13-3495, West Virginia concluded that implementing this technology on the boiler feedwater pumps is not reasonable due to the projected cost.

Section 3.1.2.1 of the Black & Veach report discusses the analysis of VFDs on the large forced draft fans; however, forced draft fans are not included in the definition of "variable frequency drive" under 40 C.F.R. § 60.5805a and therefore no additional discussion is required.

Section 3.1.2.2 of the Black & Veach report discusses the analysis of VFDs on induced draft fans. The LVP utilizes axial-type fans with single speed motors and controlled by modulating blade position (variable blade pitch controls). Axial fans with blade modulation operate at a very efficient load profile, reducing the benefits associated with VFD operation. In the 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. Heat rate improvement potential is negligible at full load (782 MW gross) and 0.028 percent at low load (475 MW

[33] *Ibid.*
[34] U.S. EPA Docket ID Number EPA-HQ-OAR-2017-0355-2117.

gross) for an estimated total installed capital cost of $3,650,000 for two fans and an additional annual operational and maintenance cost of $6,000 per unit. The recommendation states:

> 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.[35]

In the Engineering Evaluation corresponding to Permit R13-3495, West Virginia DAQ summarizes the conclusion that VFD technology is not feasible for LVP's forced- and induced-draft fans by stating:

> In the ACE Rule, EPA noted that the VFD technology would be an ideal choice for applications with centrifugal fans on units that are load cycling (load following)[36]. The writer agrees this is EPA's ideal application for this technology. LVP's unit configuration and operational mode does not fall within this ideal application for the VFD technology.
>
> Axial fans, in general, are more efficient than centrifugal fans. Coupling an axial fan with variable pitch blades is very efficient over an entire operating range. Thus, the expected HRI is not observed when adding VFD technology to LVP's fans. The writer believes that VFD technology is not feasible for LVP's forced- and induced-draft fans.

Blade Path Upgrade (Steam Turbine)

Upgrades or technology improvements, such as blade path upgrades, to steam turbines are dependent on the original design of the specific turbine and original equipment manufacturers (OEM). There are other factors that the owners/operators must consider before electing to embark on a blade path upgrade, including assuring a sufficient generator size to handle the increased turbine power output and confirming that the current steam generator can maintain optimal steam conditions (pressure and temperature) required by the turbine steam path upgrade.

Of the HRI required to be evaluated under the ACE rule, blade path upgrades for steam turbines offers the greatest potential return on investment, greatest potential in improving the unit's heat rate, and is the most expensive to implement. For some units, the steam generator may have to be modified to generate the optimum steam conditions for the blade path to see the projected HRI.

The blade path for the steam turbines had BAT applied as part of the base design LVP when the SB1 unit originally commissioned in 2011. LVP's SB1 unit utilizes a Siemens SST-6000 steam turbine to harness the potential energy of the steam and transmits it to the generator. The turbine configuration includes a high-pressure (HP) turbine, intermediate pressure (IP) turbine, and two low-pressure (LP) turbines. This configuration has a single reheat which takes the steam exhaust from the HP turbine and reheats it in the reheat section of the boiler.

The HP turbine is a single flow, double shell, with a stationary blade carrier and outer casing. The IP and two LP arrangement provides opposed double flow and compensates for axial thrust.

[35] *Ibid.*, Page 3-9.
[36] 84 Fed. Reg. 32539 (July 8, 2019).

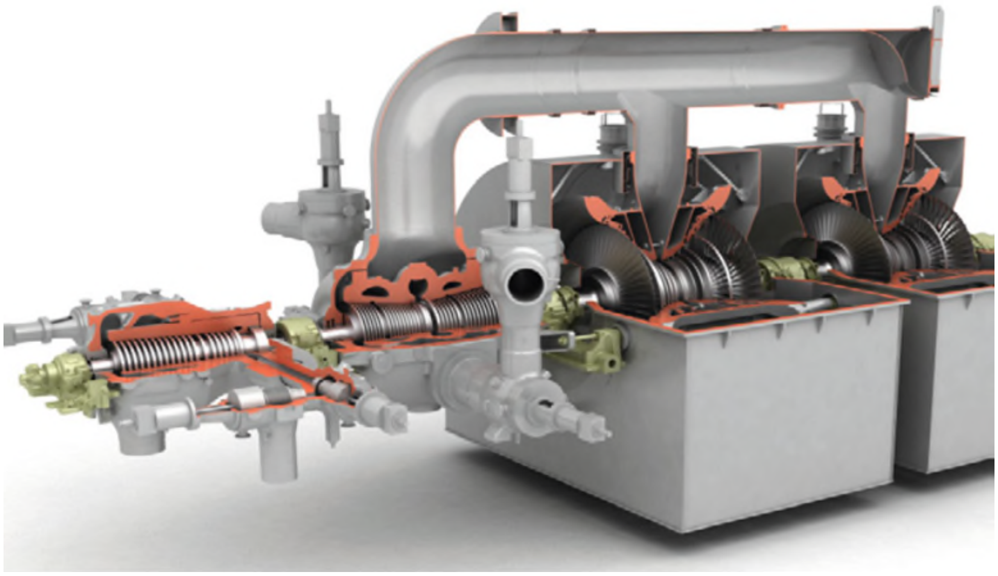

Figure C-23. Siemens SST-6000 Steam Turbine Cut-away

Siemen's advanced design with improved blade and sealing design for tighter clearances increase energy conversion (transfer) from the steam into mechanical work. The blade paths for both the HP and IP turbines are composed entirely of three-dimensional airfoil construction.

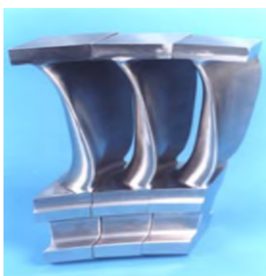

Figure C-24. Airfoil construction.

Siemens claims that the SST-6000 package has an efficiency of greater than 48%. As of June 2015, there are 488 units of the SST-6000 package series operating worldwide. Currently, Siemens does not offer any blade path improve option for the SST-6000 series. Therefore, the blade path upgrade HRI technology is not a feasible option for LVP's SST-6000 turbine package.

Redesign/ Replace Economizer

Economizers are basically tubular heat transfer surfaces used to preheat boiler feedwater before it enters to furnace pass or wall tubes for once through units. The economizer is a heat exchanger that is used to recover a portion of the residual heat energy in the flue gas exhaust as it exits the steam generator (boiler) to pre-heat the feedwater. The improvements for the economizer in terms of the unit's heat rate is to capture additional heat energy in the exhaust and transfer this energy into the feedwater. The goal of improvements to the economizer in terms of the unit's heat rate is to capture additional heat energy in the exhaust and transfer this energy into the feedwater.

The Economizer was included in the BAT applied as part of the base design when the SB1 unit was originally commissioned by LVP in 2011. The economizer at the LVP uses bare tubes. Bare tubes are the most common and reliable economizer design for coal-fired units. The bare tube, in-line arrangement minimizes the like hood of erosion and trapping of ash on the tube surfaces.

The SB1 unit utilizes a Selective Catalytic Reduction (SCR) device to control oxides of nitrogen (NO_x) emissions. The SCR is located downstream of the economizer. The heat transfer efficiency of the economizer will affect the performance of the SCR. Typically, SCRs needs an inlet exhaust temperature of 630 to 800 degrees Fahrenheit (ºF) for the initial the reaction required to operate the SCR. At full load conditions of the unit, LVP maintains a minimum exhaust temperature for the SCR of 670ºF. To optimize NO_x, LVP needs to maintain a flue gas temperature of 680ºF. To maintain this minimum flue gas temperature, they utilize an economizer by-pass, which allows a portion of the hot flue exhaust gases to be routed around the economizer to maintain the temperature flue gases above minimum temperature before entering the SCR.

Other factors that need to be considered when evaluating a re-design and replacement change is the acid gas dew point and velocities of the flue gas. Excessive corrosion in the ductwork, pollution control devices, induce-draft fans, and other downstream equipment will develop when dropping the temperature of the flue gas below the acid gas dew point, which can happen with a more efficient economizer.

With coal-fired EGUs, the gas side velocities in the economizer need to be limited due to the erosion potential of the flyash in the flue gas. Higher gas side velocities in the economizer would provide better heat transfer and reduce the capital cost of the economizer re-design and replacement. This design criteria needs to be carefully considered. LVP typically burns a high ash coal.

In the permit application for R13-3495, LVP claims the original economizer design is sized correctly for the SB1 unit. Redesign of the economizer would not allow the unit to take advantage of any gains in the unit's heat rate without adversely effecting downstream pollution control devices or increasing the degradation of downstream ductwork and other pieces of equipment. Should LVP consider redesigning the economizer, any such redesign would need to be evaluated in regard to the performance of the SCR and whether such performance change would trigger a major modification of the major source permitting requirements under the New Source Review Program of the Clean Air Act, as amended.

The West Virginia DAQ agrees with LVP that a redesigned economizer would not offer any heat rate improvement without affecting the unit's ability to control NO_x emissions.

<u>Improved Operating and Maintenance (O&M) Practices</u>

In the preamble to the ACE rule, the U.S. EPA identifies the following O&M actions for States to evaluate opportunities for HRI: (a) adopt HRI training for O&M staff, (b) perform on-site appraisals to identify areas for improved heat rate performance, and improved steam surface condenser cleaning[37]. It is clear

[37] 84 Fed. Reg. 32540 (July 8, 2019).

when reviewing the list of O&M practices employed at LVP below that the opportunities for HRI provided in the preamble of the ACE rule have been evaluated and are established at LVP.

The following is a list of measures, programs, and other notable improvements that LVP employs and should be considered as HRI under this category:

- Online condenser cleaning
- Online air heater baskets cleaning
- Air Leakage monitoring system
- Online condenser performance monitoring system
- Online Performance Monitoring (OPM) System that continuous determines the heat rate of the unit
    - o Internal and third-party evaluation of the monitored heat rate
    - o Real time performance modeling (ASME-based on Performance Test Code)
- Condition Assessments of equipment to insure operating in normal expected bands of equipment performance.
    - o Pumps stay on pump curves
    - o Fans stay on fan curves
    - o Heat exchangers and condensers performance
- Maintenance and Reliability Practices
    - o Proactive maintenance practices
    - o Pulverizer maintenance and performance program
    - o Annual critical valve leak study
    - o Annual and ongoing tuning of the control systems
    - o Computerized Manager Maintenance System to manage workflow of relevant O&M resources
- Training
    - o All personnel are trained on Heat Rate Fundamentals
    - o Operations, Maintenance, and Reliability Sections have attended Heat Rate and Combustion Fundamentals
    - o Reliability and Performance Section have received additional ongoing training to include General Physics "Fundamentals on Power Plant Performance"
    - o Peer group review and continuous learning and improvement

After resolving the unit's original design issues in 2015, LVP's reliability programs have significantly improved the unit performance which is noted by observing the change in operating hours in Figure C-25.

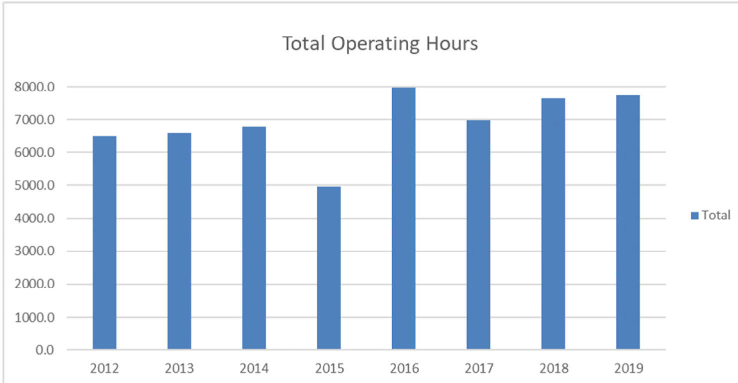

Figure C-25. Total Operating Hours 2012 – 2019.

In 2014, LVP began using Black & Vetch's On-line Performance Monitoring System (OPM) which is a real-time ASME thermodynamic model to continuously monitor and assess unit performance including heat rate to prevent and/or mitigate performance degradation due to a variety of factors. The OPM determines the net heat rate on an hourly basis using real time operational data. Advanced monitoring and diagnostics with an artificial intelligence learning system is continuously used to identify changes in the process that can impact reliability and performance of the facility. LVP utilizes third-party subject matter experts for performance to help troubleshoot or identify any abnormal operation or condition.

As part of the R13-3495 permit application, LVP provided the West Virginia DAQ a copy of this data from 2014 through the second Quarter of 2020 and the raw data is provided in Appendix F to the State Plan. Figure C-26 below shows the improvement in the SB1 unit's heat rate.

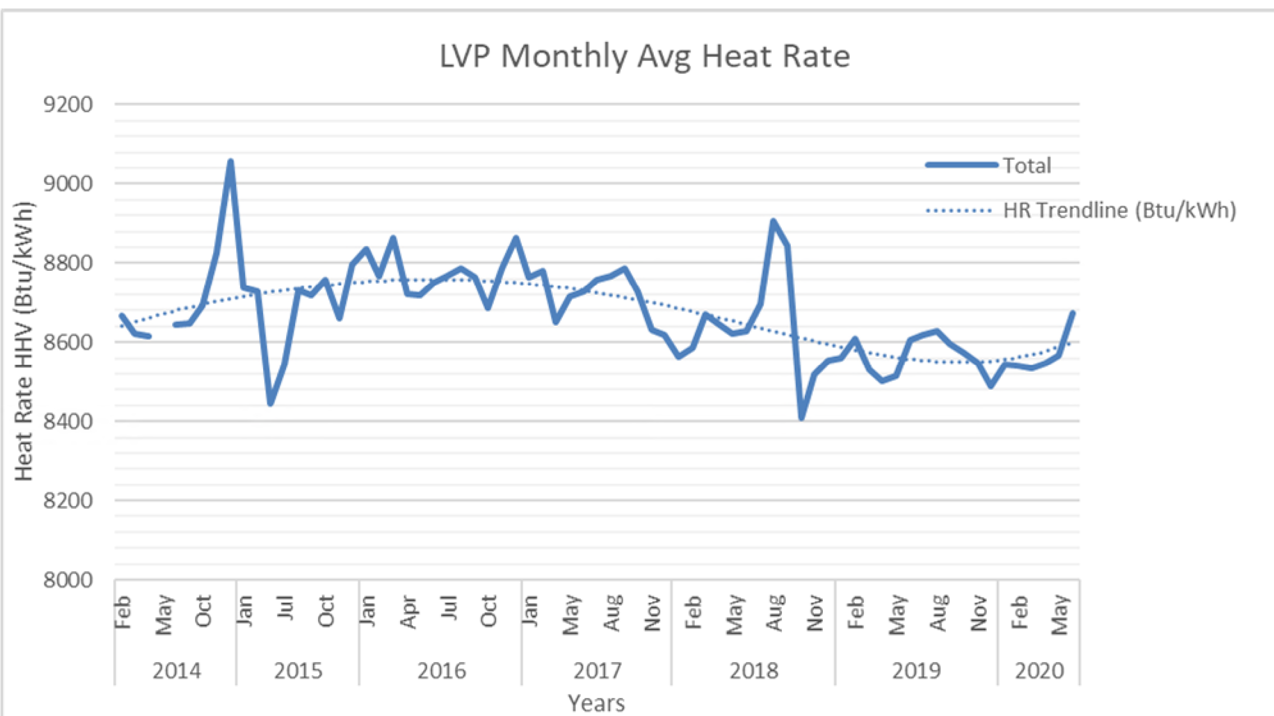

Figure C-26. LVP Monthly Average Heat Rate (2014 - 2Q 2020)

LVP's heat rate is 8,904 Btu/kWh[38]. The U.S. EPA determined that the most efficient units are units with a heat rate of less than 9,773 Btu/kWh.[39] The most advanced coal fired EGU in the nation is the American Electric Power (AEP) John W. Turk Jr. Power Plant located in Arkansas which is an ultra-supercritical steam generating unit with a capacity of 609 MW and a heat rate of 9,102 Btu/kWh[40].

LVP was unable to quantify the actual HRI resulting from the listed O&M improvements. The OPM HR data clearly suggests that these efforts, on a collective basis, are improving the SB1 unit HR. Over time, key components or equipment will wear down. As result of normal wear and tear of components such a pumps and turbine blades, the NPHR of any unit will increase which is referred to as unit degradation. LVP expects that the trend line in Figure C-26 will continue to climb with periods of decreases when these key components are repaired. LVP plans to conduct minor repair outages once every five year and major turbine repair work once every ten years. These minor and major maintenance outages should minimize the SB1 unit degradation as much as possible.

Several of the O&M measures that LVP has implemented include monitoring the performance of critical components which allows LVP to properly allocate resources and materials for the minor and major repair outages in efforts to regain the unit efficiency (heat rate).

LVP has initiated many programs, activities, and trainings as HRI under the O&M category. LVP has adopted all of the O&M measures the U.S. EPA identified in the preamble to the ACE rule, which include HRI training for O&M staff, on-site appraisals to identify areas for improved heat rate performance, and improved steam surface condenser cleaning. West Virginia DAQ does not believe that additional HRI from the O&M technology category can be achieved.

Conclusion of the HRI Evaluations

After a detailed analysis of the BSER candidate technologies specific to the LVP SB1 unit, West Virginia concludes that no additional HRI can be achieved from the candidate technologies listed in 40 C.F.R. § 60.5740a(a)(1) in accordance with 40 C.F.R. § 60.5740a(a)(2). This conclusion is consistent with the U.S. EPA's assessment in the RIA to the ACE rule that the most efficient EGUs in Group 1 "are assumed to be very well maintained and to have already implemented available HRI technologies"[41].

E. ANTICIPATED FUTURE OPERATION CHARACTERISTICS, AS APPLICABLE [40 C.F.R. § 60.5740a(a)(4)]

LVP routinely dispatches as a base load unit within the competitive PJM wholesale market. The future of an open and competitive marketplace is not subject to definitive future outcomes and, therefore, cannot be effectively forecast to gain certainty for generation patterns, capacity factors, electric power prices, fuel use patterns or consumptions. Since these cannot be gained in a certain manner, maintenance efforts and associated costs cannot be accurately determined. As a result, LVP could only forecast the near-term

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[38] U.S. EPA National Electric Energy Data System (NEEDS) v620 rev: 10-05-20.
[39] Regulatory Impact Analysis for the Repeal of Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, EPA-452/R-19-003, June 2019, Table 3-1, page 3-6.
[40] U.S. EPA National Electric Energy Data System (NEEDS) v620 rev: 10-05-20.
[41] Regulatory Impact Analysis for the Repeal of Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, EPA-452/R-19-003, June 2019, Table 3-1, page 1-16.

expectation of net generation, capacity factors and maintenance requirements. Detailed forecasts are critical and vital to LVP's competitiveness and are considered proprietary and confidential.

Given these limitations, and a projected unit service life of approximately 30 to 40 years, LVP believes that the future operations for this facility will remain as a base load unit with relatively high capacity factors and that maintenance efforts will remain sufficient to sustain reliability, compliance, and safety of the facility well into the future. Table C-11 presents the applicable anticipated future operating characteristics for LVP. Any further attempted prediction of future operations beyond what is provided in Table C-11 is not possible. West Virginia did not require additional information to perform a detailed analysis and develop standards of performance for LVP. For reasons discussed in the subsequent paragraphs, the following characteristics are not applicable: fuel prices, fixed and variable operations and maintenance costs, and wholesale electricity prices.

In evaluating the BSER HRI technologies, none of the technologies were determined to be infeasible based on cost alone. Specifically, for the O&M technologies, LVP has already implemented all the measures identified in the preamble to the ACE rule and believes it would be financially feasible to implement these measures if they were not already established at LVP. Thus, West Virginia does not consider the projected fuel prices and O&M costs applicable to establish a standard of performance for LVP.

LVP is a non-rate payer unit, which means the rate that LVP charges for their electricity is not regulated by the Public Service Commission for the State of West Virginia. The rate at which LVP receives compensation for their electricity generation is dependent upon the actual market price. Again, the schema of wholesale electricity pricing was not used to justify why any of the O&M measures were infeasible. Thus, the projected pricing is not applicable to the process of establishing a standard.

The timeline for implementation, as required by 40 C.F.R. § 60.5740a(a)(4)(ii), is provided in condition 4.4.5 of Permit R13-3495 that is included as Appendix I to the State Plan. The initial compliance period shall begin on January 1, 2021 and end on December 31, 2021. Subsequent compliance periods follow thereafter.

Table C-11. LVP Anticipated Future Operation Characteristics.

Year	Annual Net Generation (MW)	CO2 Emissions (1000 of tons)	Fuel Use (1000 of tons)	Fuel Carbon Content (1000 of tons)	Heat Rate (Btu/kWh)	Electric Generation Capacity	Capacity Factor
2020	5,087	5,212	1758	1231	8815	6149	83%
2021	5,250	5400	1822	1275	8851	6132	85%
2022	5,410	5587	1885	1319	8885	6132	88%
2023	5,174	5365	1783	1248	8922	6132	84%
2024	5,124	5286	1875	1313	8872	6149	83%
2025	5,368	5560	1875	1313	8912	6132	88%
2026	5,423	5640	1903	1332	8948	6132	88%
2027	5,514	5757	1942	1360	8984	6132	90%
2028	5,470	5734	1934	1354	9020	6149	89%
2029	5,191	5415	1827	1279	8975	6132	85%
2030	5,571	5834	1968	1378	9011	6132	91%
2031	5,454	5734	1935	1354	9047	6132	89%
2032	5,416	5717	1929	1350	9083	6149	88%
2033	5,290	5606	1891	1324	9119	6132	86%
2034	4,991	5311	1792	1254	9156	6132	81%
2035	5,548	5874	1982	1387	9110	6132	90%

F. DEMONSTRATION THAT THE STANDARDS OF PERFORMANCE MEET THE REQUIREMENTS OF 40 C.F.R. § 60.5755a [40 C.F.R. § 60.5740a(a)(4)(v)]

Table C-12 below identifies the location in the State Plan where the demonstration can be found for each of the requirements of 40 C.F.R. § 60.5755a.

Table C-12. Demonstration of 40 C.F.R. § 60.5755a.

ACE Requirement:	WV State Plan Location:
§60.5755a(a)	4.4.c & Appendix C, Section A
§60.5755a(a)(1)	4.4.a, 4.4.c & Appendix C, Section B
§60.5755a(a)(2)	4.4.c & Appendix C, Sections C and D
§60.5755a(b)	4.4.c & Appendix D
§60.5755a(c)	4.4.c & Appendix D
§60.5755a(d)	4.4.c & Appendix D
§60.5755a(e)	4.4.c & Appendix D
§60.5755a(f)	4.4.c & Appendix D