WV ACE Partial State Plan

Appendix I

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Appendix I
Table of Contents

Appendix I: Longview Power LLC………...Page I-1
Permit R13-3495 (Signed)…..……………………………….……………………Page I-5
Final Determination/Response to Comments (Signed)…………………………..Page I-31
Response to Comment Communication…………………………….…………Page I-83
Comments Received ……………………………………………..…………Page I-85
Joe Robinson……………………………………………………..……Page I-87
Bill Reger-Nash…………………………………………..…………Page I-89
Betsy Lawson…………………………………………………….…Page I-91
Stephen Lawson……………………………………………………..Page I-93
Sierra Club WV - James Kotcon………………………………;;;…….Page I-97
Mon Valley Clean Coalition - Duane G. Nichols………………………...Page I-103
WV Attorney General – Patrick Morrisey………………………………Page I-105
WV 3rd Congressional District – Carol Miller…………………………..Page I-109
WV Congressional Delegation (Capito, McKinley, Mooney, & Miller…Page I-113
Public Meeting Questions (All)…………………………………..…..Page I-117
Public Notice……………………………………………………………….Page I-123
Engineering Evaluation for Permit R13-3495 (Signed).....…….……………......Page I-125
Draft Permit R13-3495 (Signed)…………………………………………..….Page I-199
Other Administrative Records for Permit R13-3495……………………..……..Page I-225

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West Virginia Department of Environmental Protection

Austin Caperton
Cabinet Secretary

Construction Permit

R13-3495

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§22-5-1 et seq.) and 45 C.S.R. 13 – Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits, Permission to Commence Construction, and Procedures for Evaluation. The permittee identified at the above-referenced facility is authorized to construct the stationary sources of air pollutants identified herein in accordance with all terms and conditions of this permit.

Issued to:
Longview Power LLC
Maidsville
061-00134

Laura M. Crowder
Director, Division of Air Quality

Issued: December 23, 2020

Facility Location:	1375 Fort Martin Road Maidsville, Monongalia County, West Virginia 26541
Mailing	Same as Above
Facility Description:	Electric Generation Unit
NAICS Codes:	221112
UTM Coordinates:	580.6 km Easting • 4,306.9 km Northing • Zone 17
Permit Type:	Construction
Description of Change:	This action is for establishing a standard of performance emission limit for carbon dioxide emitted from the Pulverized Coal-Fired Steam Generating Unit (PC-Boiler) in accordance with the Emission Guidelines of 40 CFR Part 60, Subpart UUUUa.

Any person whose interest may be affected, including, but not necessarily limited to, the applicant and any person who participated in the public comment process, by a permit issued, modified or denied by the Secretary may appeal such action of the Secretary to the Air Quality Board pursuant to article one [§§22B-1-1 et seq.], Chapter 22B of the Code of West Virginia. West Virginia Code §§22-5-14.

The source is subject to 45CSR30. Changes authorized by this permit must also be incorporated into the facility's Title V operating permit. Commencement of the operations authorized by this permit shall be determined by the appropriate timing limitations associated with Title V permit revisions per 45CSR30.

Table of Contents

1.0. Emission Units..4

2.0. General Conditions..5
2.1. Definitions 5
2.2. Acronyms..5
2.3. Authority...5
2.4. Term and Renewal 6
2.5. Duty to Comply 6
2.6. Duty to Provide Information...6
2.7. Duty to Supplement and Correct Information..6
2.8. Administrative Update 7
2.9. Permit Modification..7
2.10 Major Permit Modification 7
2.11. Inspection and Entry 7
2.12. Emergency...7
2.13. Need to Halt or Reduce Activity Not a Defense 8
2.14. Suspension of Activities 8
2.15. Property Rights 8
2.16. Severability..8
2.17. Transferability..8
2.18. Notification Requirements...9
2.19. Credible Evidence..9

3.0. Facility-Wide Requirements 10
3.1. Limitations and Standards 10
3.2. Monitoring Requirements...10
3.3. Testing Requirements 10
3.4. Recordkeeping Requirements..11
3.5. Reporting Requirements 12

4.0. Source-Specific Requirements...14
4.1. Limitations and Standards 14
4.2. Monitoring Requirements...16
4.3. Testing Requirements 18
4.4. Recordkeeping Requirements..20
4.5. Reporting Requirements 24

CERTIFICATION OF DATA ACCURACY 25

1.0. Emission Units

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
SB1	EA1	Pulverized Coal-Fired Steam Generator (PC Boiler)	1/26/2007	6,114 MMBtu/hr	SCR/DSI/FF/WFGD

SCR – Selective Catalytic Reduction for reducing nitrogen oxides emissions
DSI – Dry Sorbent Injection for reducing acid gases emissions
FF – Fabric Filter Baghouse for reducing filterable PM emissions
WFGD – Wet Flue Gas Desulfurization for reducing sulfur dioxide emissions

2.0. General Conditions

2.1. Definitions

2.1.1. All references to the "West Virginia Air Pollution Control Act" or the "Air Pollution Control Act" mean those provisions contained in W.Va. Code §§ 22-5-1 to 22-5-18.

2.1.2. The "Clean Air Act" means those provisions contained in 42 U.S.C. §§ 7401 to 7671q, and regulations promulgated thereunder.

2.1.3. "Secretary" means the Secretary of the Department of Environmental Protection or such other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8 (45CSR§30-2.12.). The Director of the Division of Air Quality is the Secretary's designated representative for the purposes of this permit.

2.2. Acronyms

CAAA	Clean Air Act Amendments
CBI	Confidential Business Information
CEM	Continuous Emission Monitor
CES	Certified Emission Statement
C.F.R. ***or*** **CFR**	Code of Federal Regulations
CO	Carbon Monoxide
C.S.R. ***or*** **CSR**	Codes of State Rules
DAQ	Division of Air Quality
DEP	Department of Environmental Protection
dscm	Dry Standard Cubic Meter
FOIA	Freedom of Information Act
HAP	Hazardous Air Pollutant
HON	Hazardous Organic NESHAP
HP	Horsepower
lbs/hr	Pounds per Hour
LDAR	Leak Detection and Repair
M	Thousand
MACT	Maximum Achievable Control Technology
MDHI	Maximum Design Heat Input
MM	Million
MMBtu/hr ***or*** **mmbtu/hr**	Million British Thermal Units per Hour
MMCF/hr ***or*** **mmcf/hr**	Million Cubic Feet per Hour
NA	Not Applicable
NAAQS	National Ambient Air Quality Standards
NESHAPS	National Emissions Standards for Hazardous Air Pollutants
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter less than 2.5 µm in diameter
PM_{10}	Particulate Matter less than 10µm in diameter
Ppb	Pounds per Batch
Pph	Pounds per Hour
Ppm	Parts per Million
Ppm_V or ppmv	Parts per Million by Volume
PSD	Prevention of Significant Deterioration
Psi	Pounds per Square Inch
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TAP	Toxic Air Pollutant
TPY	Tons per Year
TRS	Total Reduced Sulfur
TSP	Total Suspended Particulate
USEPA	United States Environmental Protection Agency
UTM	Universal Transverse Mercator
VEE	Visual Emissions Evaluation
VOC	Volatile Organic Compounds
VOL	Volatile Organic Liquids

2.3. Authority

This permit is issued in accordance with West Virginia Air Pollution Control Act W.Va. Code §§ 22-5-1. et seq. and the following Legislative Rules promulgated thereunder:

2.3.1. 45CSR13 – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation*;

2.4. Term and Renewal

2.4.1. This Permit shall remain valid, continuous and in effect unless it is revised, suspended, revoked or otherwise changed under an applicable provision of 45CSR13 or any other applicable legislative rule;

2.5. Duty to Comply

2.5.1. The permitted facility shall be constructed and operated in accordance with the plans and specifications filed in Permit Application R13-3495, and any modifications, administrative updates, or amendments thereto. The Secretary may suspend or revoke a permit if the plans and specifications upon which the approval was based are not adhered to;
[45CSR§§13-5.10 and 10.3.]

2.5.2. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the West Virginia Code and the Clean Air Act and is grounds for enforcement action by the Secretary or USEPA;

2.5.3. Violations of any of the conditions contained in this permit, or incorporated herein by reference, may subject the permittee to civil and/or criminal penalties for each violation and further action or remedies as provided by West Virginia Code 22-5-6 and 22-5-7;

2.5.4. Approval of this permit does not relieve the permittee herein of the responsibility to apply for and obtain all other permits, licenses, and/or approvals from other agencies; i.e., local, state, and federal, which may have jurisdiction over the construction and/or operation of the source(s) and/or facility herein permitted.

2.6. Duty to Provide Information

The permittee shall furnish to the Secretary within a reasonable time any information the Secretary may request in writing to determine whether cause exists for administratively updating, modifying, revoking, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Secretary copies of records to be kept by the permittee. For information claimed to be confidential, the permittee shall furnish such records to the Secretary along with a claim of confidentiality in accordance with 45CSR31. If confidential information is to be sent to USEPA, the permittee shall directly provide such information to USEPA along with a claim of confidentiality in accordance with 40 C.F.R. Part 2.

2.7. Duty to Supplement and Correct Information

Upon becoming aware of a failure to submit any relevant facts or a submittal of incorrect information in any permit application, the permittee shall promptly submit to the Secretary such supplemental facts or corrected information.

2.8. Administrative Update

The permittee may request an administrative update to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-4.]

2.9. Permit Modification

The permittee may request a minor modification to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-5.4.]

2.10 Major Permit Modification

The permittee may request a major modification as defined in and according to the procedures specified in 45CSR14 or 45CSR19, as appropriate.
[45CSR§13-5.1]

2.11. Inspection and Entry

The permittee shall allow any authorized representative of the Secretary, upon the presentation of credentials and other documents as may be required by law, to perform the following:

a. At all reasonable times (including all times in which the facility is in operation) enter upon the permittee's premises where a source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect at reasonable times (including all times in which the facility is in operation) any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

d. Sample or monitor at reasonable times substances or parameters to determine compliance with the permit or applicable requirements or ascertain the amounts and types of air pollutants discharged.

2.12. Emergency

2.12.1. An "emergency" means any situation arising from sudden and reasonable unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

2.12.2. Effect of any emergency. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions of Section 2.12.3 are met.

2.12.3. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. An emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. The permitted facility was at the time being properly operated;

c. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

d. The permittee submitted notice of the emergency to the Secretary within one (1) working day of the time when emission limitations were exceeded due to the emergency and made a request for variance, and as applicable rules provide. This notice must contain a detailed description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

2.12.4. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.

2.12.5 The provisions of this section are in addition to any emergency or upset provision contained in any applicable requirement.

2.13. Need to Halt or Reduce Activity Not a Defense

It shall not be a defense for a permittee in an enforcement action that it should have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in determining penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continued operations.

2.14. Suspension of Activities

In the event the permittee should deem it necessary to suspend, for a period in excess of sixty (60) consecutive calendar days, the operations authorized by this permit, the permittee shall notify the Secretary, in writing, within two (2) calendar weeks of the passing of the sixtieth (60) day of the suspension period.

2.15. Property Rights

This permit does not convey any property rights of any sort or any exclusive privilege.

2.16. Severability

The provisions of this permit are severable and should any provision(s) be declared by a court of competent jurisdiction to be invalid or unenforceable, all other provisions shall remain in full force and effect.

2.17. Transferability

This permit is transferable in accordance with the requirements outlined in Section 10.1 of 45CSR13.
[45CSR§13-10.1.]

2.18. Notification Requirements

The permittee shall notify the Secretary, in writing, no later than thirty (30) calendar days after the actual startup of the operations authorized under this permit.

2.19. Credible Evidence

Nothing in this permit shall alter or affect the ability of any person to establish compliance with, or a violation of, any applicable requirement through the use of credible evidence to the extent authorized by law. Nothing in this permit shall be construed to waive any defense otherwise available to the permittee including, but not limited to, any challenge to the credible evidence rule in the context of any future proceeding.

3.0. Facility-Wide Requirements

3.1. Limitations and Standards

3.1.1. **Open burning.** The open burning of refuse by any person, firm, corporation, association or public agency is prohibited except as noted in 45CSR§6-3.1.
[45CSR§6-3.1.]

3.1.2. **Open burning exemptions.** The exemptions listed in 45CSR§6-3.1 are subject to the following stipulation: Upon notification by the Secretary, no person shall cause, suffer, allow or permit any form of open burning during existing or predicted periods of atmospheric stagnation. Notification shall be made by such means as the Secretary may deem necessary and feasible.
[45CSR§6-3.2.]

3.1.3. **Asbestos.** The permittee is responsible for thoroughly inspecting the facility, or part of the facility, prior to commencement of demolition or renovation for the presence of asbestos and complying with 40 C.F.R. § 61.145, 40 C.F.R. § 61.148, and 40 C.F.R. § 61.150. The permittee, owner, or operator must notify the Secretary at least ten (10) working days prior to the commencement of any asbestos removal on the forms prescribed by the Secretary if the permittee is subject to the notification requirements of 40 C.F.R. § 61.145(b)(3)(i). The USEPA, the Division of Waste Management, and the Bureau for Public Health - Environmental Health require a copy of this notice to be sent to them.
[40CFR§61.145(b) and 45CSR§34]

3.1.4. **Odor.** No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor at any location occupied by the public.
[45CSR§4-3.1] ***[State Enforceable Only]***

3.1.5. **Permanent shutdown.** A source which has not operated at least 500 hours in one 12-month period within the previous five (5) year time period may be considered permanently shutdown, unless such source can provide to the Secretary, with reasonable specificity, information to the contrary. All permits may be modified or revoked and/or reapplication or application for new permits may be required for any source determined to be permanently shutdown.
[45CSR§13-10.5.]

3.1.6. **Standby plan for reducing emissions.** When requested by the Secretary, the permittee shall prepare standby plans for reducing the emissions of air pollutants in accordance with the objectives set forth in Tables I, II, and III of 45CSR11.
[45CSR§11-5.2.]

3.2. Monitoring Requirements

[Reserved]

3.3. Testing Requirements

3.3.1. **Stack testing.** As per provisions set forth in this permit or as otherwise required by the Secretary, in accordance with the West Virginia Code, underlying regulations, permits and orders, the permittee shall conduct test(s) to determine compliance with the emission limitations set forth in this permit and/or established or set forth in underlying documents. The Secretary, or his duly authorized representative, may at his option witness or conduct such test(s). Should the Secretary exercise his option to conduct such test(s), the operator shall provide all necessary sampling connections and sampling ports to be located in such manner as the Secretary may require, power for test equipment and the required safety equipment, such as scaffolding, railings and ladders, to comply with generally accepted good safety practices. Such tests shall be conducted in accordance with the methods and procedures set forth in this permit or as otherwise approved or specified by the Secretary in accordance with the following:

a. The Secretary may on a source-s-pecific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with 40 C.F.R. Parts 60, 61, and 63 in accordance with the Secretary's delegated authority and any established equivalency determination methods which are applicable. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.

b. The Secretary may on a source-specific- basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with applicable requirements which do not involve federal delegation. In specifying or approving such alternative testing to the test methods, the Secretary, to the extent possible, shall utilize the same equivalency criteria as would be used in approving such changes under Section 3.3.1.a. of this permit. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.

c. All periodic tests to determine mass emission limits from or air pollutant concentrations in discharge stacks and such other tests as specified in this permit shall be conducted in accordance with an approved test protocol. Unless previously approved, such protocols shall be submitted to the Secretary in writing at least thirty (30) days prior to any testing and shall contain the information set forth by the Secretary. In addition, the permittee shall notify the Secretary at least fifteen (15) days prior to any testing so the Secretary may have the opportunity to observe such tests. This notification shall include the actual date and time during which the test will be conducted and, if appropriate, verification that the tests will fully conform to a referenced protocol previously approved by the Secretary.

d. The permittee shall submit a report of the results of the stack test within sixty (60) days of completion of the test. The test report shall provide the information necessary to document the objectives of the test and to determine whether proper procedures were used to accomplish these objectives. The report shall include the following: the certification described in paragraph 3.5.1.; a statement of compliance status, also signed by a responsible official; and, a summary of conditions which form the basis for the compliance status evaluation. The summary of conditions shall include the following:

   1. The permit or rule evaluated, with the citation number and language;
   2. The result of the test for each permit or rule condition; and,
   3. A statement of compliance or noncompliance with each permit or rule condition.

[WV Code § 22-5-4(a)(14-15) and 45CSR13]

3.4. Recordkeeping Requirements

3.4.1. **Retention of records.** The permittee shall maintain records of all information (including monitoring data, support information, reports, and notifications) required by this permit recorded in a form suitable and readily available for expeditious inspection and review. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation. The files shall be maintained for at least five (5) years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent two (2) years of data shall be maintained on site. The remaining three (3) years of data may be maintained off site, but must remain accessible within a reasonable time. Where appropriate, the permittee may maintain records electronically (on a computer, on computer floppy disks, CDs, DVDs, or magnetic tape disks), on microfilm, or on microfiche.

3.4.2. **Odors.** For the purposes of 45CSR4, the permittee shall maintain a record of all odor complaints received, any investigation performed in response to such a complaint, and any responsive action(s) taken.
[45CSR§4. *State Enforceable Only.*]

3.5. Reporting Requirements

3.5.1. **Responsible official.** Any application form, report, or compliance certification required by this permit to be submitted to the DAQ and/or USEPA shall contain a certification by the responsible official that states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

3.5.2. **Confidential information.** A permittee may request confidential treatment for the submission of reporting required by this permit pursuant to the limitations and procedures of W.Va. Code § 22-5-10 and 45CSR31.

3.5.3. **Correspondence.** All notices, requests, demands, submissions and other communications required or permitted to be made to the Secretary of DEP and/or USEPA shall be made in writing and shall be deemed to have been duly given when delivered by hand, or mailed first class or by private carrier with postage prepaid to the address(es), or submitted in electronic format by email as set forth below or to such other person or address as the Secretary of the Department of Environmental Protection may designate:

DAQ:	**US EPA:**
Director	Section Chief
WVDEP	U.S. Environmental Protection Agency, Region III
Division of Air Quality	Enforcement and Compliance Assurance
601 57th Street	Division Air Section (3ED21)
Charleston, WV 25304-2345	1650 Arch Street
	Philadelphia, PA 19103-2029

DAQ Compliance and Enforcement[1]:
DEPAirQualityReports@wv.gov
[1]For all self-monitoring reports (MACT, GACT, NSPS, etc.), stack tests and protocols, Notice of Compliance Status Reports, Initial Notifications, etc.

3.5.4. Operating Fee

3.5.4.1. In accordance with 45CSR30 – Operating Permit Program, the permittee shall submit a certified emissions statement and pay fees on an annual basis in accordance with the submittal requirements of the Division of Air Quality. A receipt for the appropriate fee shall be maintained on the premises for which the receipt has been issued, and shall be made immediately available for inspection by the Secretary or his/her duly authorized representative.

3.5.5. **Emission inventory.** At such time(s) as the Secretary may designate, the permittee herein shall prepare and submit an emission inventory for the previous year, addressing the emissions from the facility and/or process(es) authorized herein, in accordance with the emission inventory submittal requirements of the Division of Air Quality. After the initial submittal, the Secretary may, based upon the type and quantity of the pollutants emitted, establish a frequency other than on an annual basis.

4.0. Source-Specific Requirements

4.1. Limitations and Standards

4.1.1. 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.

a. The following are the Level 1 CO_2 emissions limits for the corresponding Load Bins:

i. CO_2 emissions released while the electric steam generating unit (EGU) is operating greater than zero megawatt hour (MWh) (gross) to 313 MWh (gross), which shall be referred as Load Bin 0 (LB-0), shall have an initial bin limit not to exceed 9,864 pounds of CO_2 per MWh of gross electricity generation.

ii. CO_2 emissions released while the EGU is operating greater than 313 MWh (gross) up to 407 MWh (gross), which shall be referred as Load Bin 1 (LB-1), shall have an initial bin limit not to exceed 2,230 pounds of CO_2 per MWh of net electricity generation.

iii. CO_2 emissions released while the EGU is operating greater than 407 MWh (gross) up to 501 MWh (gross), which shall be referred as Load Bin 2 (LB-2), shall have an initial bin limit not to exceed 2,108 pounds of CO_2 per MWh of net electricity generation.

iv. CO_2 emissions released while the EGU is operating greater than 501 MWh (gross) up to 595 MWh (gross), which shall be referred as Load Bin 3 (LB-3), shall have an initial bin limit not to exceed 2,050 pounds of CO_2 per MWh of net electricity generation.

v. CO_2 emissions released while the EGU is operating greater than 595 MWh (gross) up to 689 MWh (gross), which shall be referred as Load Bin 4 (LB-4), shall have an initial bin limit not to exceed 2,002 pounds of CO_2 per MWh of net electricity generation.

vi. CO_2 emissions released while the EGU is operating greater than 689 MWh (gross), which shall be referred as Load Bin 5 (LB-5), shall have an initial bin limit not to exceed 1,958 pounds of CO_2 per MWh of net electricity generation.

b. At times when the unit has experienced an equipment failure that requires the unit to be operated at a higher heat rate (degraded efficiency), the Level 2 CO_2 Limits for Load Bins 1 through 5 shall be the Level 1 CO_2 Limits multiplied by 1.10 (ten percent above the Level 1 Limits) in accordance with the following requirements:

i. The permittee shall initially notify the Director in accordance with Condition 3.5.1. within 72-hours of experiencing such an event.

ii. Within 12 days of the initial notification, the permittee shall formally notify the Director whether or not the event will require the Level 2 CO_2 Limits be placed into effect. If so, the notification shall include a request for approval from the Director to operate under the Level 2 CO_2 Limits if the duration of the event is expected to last more than 180 days. This notification shall include the date and time when the unit commenced operations in a degraded efficiency mode, a justification that the Level 2 CO_2 Limits are required, and the expected duration of the Level 2 event. If the duration of the event is expected to end within 180 days of its commencement, the operation under the Level 2 CO_2 Limits shall be deemed approved unless the permittee is notified by the Director within fifteen (15) days of the formal notification that the event does not qualify as a Level 2 event. If the duration of the event is expected to last more than 180 days, the Director shall notify the permittee within 30 days on whether or not the event qualifies as a Level 2 event and thereby being approved or disapproved.

iii. Within thirty days after the confirmed commencement of an event requiring Level 2 CO_2 Limits, the permittee shall develop and submit a corrective action plan to the Director. Within the plan, the permittee must identify the defective component/piece of equipment, identify repairs necessary to restore the unit's performance, and project the duration that the Level 2 Limits will be in effect. Such plan must identify milestones of critical tasks; identify resources needed for the repair(s) to include labor, materials, and special equipment; and include a projected timeline of restoring the unit. The permittee, upon request, may extend the projected duration with written approval by the Director. No individual period that the Level 2 CO_2 Limits are in affect shall extend beyond 24 months.

iv. The permittee shall submit reports of the status of the corrective action plan at least once every two months. These reports shall include the number of hours the unit has operated in Load Bin 1 through 5 during the period, the average net heat rate of the unit, and the average CO_2 emission rate in lb/MWh net for the period.

v. Within fifteen (15) days of restoring the unit's efficiency, the permittee shall notify the director that the Level 2 CO_2 Limits are no longer being utilized and that the unit has reverted back to the Level 1 CO_2 Limits. Within ninety (90) days of restoring the unit's efficiency, the permittee shall prepare a Root Cause Analysis (RCA) report of the event. The report shall identify the cause, identify corrective actions to prevent future failure(s) and/or measures to reduce the duration to complete repair for Level 2 CO_2 Limits durations that extend beyond six months. The report shall note total number of hours the unit has operated in Load Bins 1 through 5 during the period, the average net heat rate of the unit, and the average CO_2 emission rate in lb/MWh net for the period. In the event that a RCA may not be finalized within the 90 day period, a schedule shall be submitted detailing the reason(s) for non-completion as well as a timeline for completion.

vi. The Level 2 CO_2 Limit does not apply to an event that causes a forced unit outage in which all repairs necessary to restart the unit may be completed immediately and renders the unit capable of achieving the Level 1 CO_2 Limit. In accordance with Condition 2.12., if repairs that would restore the unit to the Level 1 CO_2 Limit performance are not feasibly achievable, the Level 2 CO_2 Limit may be utilized by following the procedures in Condition 4.1.1.b.

All notifications and reports stipulated in Condition 4.1.1.b shall be submitted in accordance with Condition 3.5.3. and records of such submissions shall be maintained in accordance with Condition 3.4.1.

c. Unit degradation adjustment Factor (UDAF) - After the initial compliance period, the CO_2 limit for each of the load bins in Condition 4.1.1.a. shall be adjusted (increased) annually by 0.4%. Once every five years after the initial compliance period, a recovery (decreased) percentage of 0.7% shall be applied to the individual CO_2load bin limits. The 0.7% recovery shall be applied to the most recent CO_2 limits adjusted by the annual 0.4% UDAF. The UDAF shall be applied up to and including calendar year 2046. Beginning with calendar year 2047, the UDAF shall no longer be applied and the CO_2 Load Bin limits shall remain at the 2046 levels.

d. Coal adjustment factor (CAF) shall be applied to the Level 1 and Level 2 CO_2 Limits with the appropriate UDAF applied limits. The CAF shall be the ratio of future CO_2 emissions divided by the baseline CO_2 emissions as determined in accordance with Condition 4.3.1.

The CAF is only applicable when the permittee requires a fuel switch that results in the different source of coal that the permittee 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, will increase or decrease 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.

4.1.2. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, maintain, and operate all pollution control equipment listed in Section 1.0 and associated monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions, or comply with any more stringent limits set forth in this permit or as set forth by any State rule, Federal regulation, or alternative control plan approved by the Secretary.
[45CSR§13-5.10.]

4.2. Monitoring Requirements

4.2.1. The permittee must determine the hourly CO_2 mass emissions in pounds from the emission point EA1 according to the following paragraphs.

a. The permittee shall install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR §75.10(a)(3)(i). If the permittee measures CO_2 concentration on a dry basis, the permittee must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR §75.11(b).

b. For each continuous monitoring system that the permittee uses to determine the CO_2 mass emissions, the permittee must meet the applicable certification and quality assurance procedures in 40 CFR §75.20 and appendices A and B to 40 CFR Part 75.

c. The permittee must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; the permittee must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR Part 75 to the exhaust gas flow rate data.

d. The permittee must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR Part 75. If the permittee uses a Type-S pitot tube or a pitot tube assembly for the flow RATAs, the permittee must calibrate the pitot tube or pitot tube assembly. The permittee may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2 in appendix A to 40 CFR Part 60.

e. Calculate the hourly CO_2 mass emissions (lb) as described in Condition 4.2.1.(e)(i) through (iii) of this section. Perform this calculation only for “valid operating hours”, as defined in 40 CFR §60.5540(a)(1).

i. Begin with the hourly CO_2 mass emission rate (pounds/hr), obtained either from Equation F-11 in appendix F to 40 CFR Part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to 40 CFR Part 75 (if CO_2 concentration is measured on a dry basis).

ii. Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR §72.2), to convert it to tons of CO_2.

iii. The hourly CO_2 (pounds/hr) values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR §75.57(e) and must be reported electronically under 40 CFR §75.64(a)(6). The permittee must use these data to calculate the hourly CO_2 mass emissions.

f. The permittee shall record the length of time that the EGU operated within each load bin as defined in Condition 4.1.1. a through b.

g. The permittee shall maintain records of maintenance performed, calibrations, performance evaluations, and CEMS data in accordance with Condition 3.4.1.

4.2.2. The permittee must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross and net electric output, as applicable, from the permitted EGU. These instruments must use 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20 (incorporated by reference, see 40 CFR §60.17). The permittee shall maintain records of maintenance performed, calibrations, performance evaluations, and data within a data collection system in accordance with Condition 3.4.1.

4.2.3. The permittee shall maintain and operate a system that measures, records operational data of the EGU and calculates the unit heat rate in terms of Btu per kilowatt-hour based on using a Rankine cycle model of the permitted unit in accordance with latest version of the American Society of Mechanical Engineers (ASME) Performance Test Code Performance Monitoring Guidelines for Power Plant (ASME PTC PM-2010) or future test method developed by ASME to measure the heat rate from power plant. Records of the calculated heat rate reduced to hourly values and maintenance performed on the system shall be maintained in accordance with Condition 3.4.1.

4.2.4. The permittee shall evaluate the data as required to be collected under Condition 4.2.1. to determine if the data is “valid data” using the criteria set forth in this condition. Each compliance period shall include only “valid operating hours” in the compliance period, i.e., operating hours for which:

a. “Valid data” is defined as quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to 40 CFR Part 75. For CEMS, the initial certification requirements in 40 CFR §75.20 and appendix A to 40 CFR Part 75 must be met before quality-assured data are reported under this permit. For on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to 40 CFR Part 75 must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to 40 CFR Part 75 apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to 40 CFR Part 75 must be met before quality-assured data are reported under this permit, and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to 40 CFR Part 75 apply.

b. "Valid data" are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (lb) and,

c. The corresponding hourly net energy output value is also valid data (Note: For hours with no useful output, zero is considered to be a valid value).

d. The permittee must exclude operating hours in which:

i. The substitute data provisions of 40 CFR Part 75 are applied for any of the parameters used to determine the hourly CO_2 mass emissions; or

ii. An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

iii. The total net energy output is unavailable.

e. For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph a of this condition.

i. At times when the CEMS CO_2 emission data falls below the above 95% threshold during the compliance period, the permittee shall use the procedures from Appendix G to 40 CFR Part 75 to determine the CO_2 emissions for the periods when CO_2 emissions data is missing.

f. The permittee must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from monitored data collected under Condition 4.2.1. for all the valid operating hours for each month within the compliance period.

4.3. Testing Requirements

4.3.1. Within 90 days prior to conducting a fuel switch that the permittee has determined an adjustment to the CO_2 limit is needed, the permittee shall conduct emission testing to establish the CAF to be applied to the CO_2 limit. Such testing shall be conducted by an independent third-party to establish the following:

a. Establish baseline of CO_2 emissions of the current coal utilized with the unit operating in Load Bin 5 for at least 90% of the operating hours during a consecutive operating period of no less than 7 operating days.

i. Determine the CO_2 emissions of the future coal with the unit operating in Load Bin 5 for at least 90% of the operating hours during a consecutive operating period of no less than 7 operating days.

ii. The standard deviation of the CO_2 emissions data used in the ratio to develop the CAF for each of the two phases (baseline and future coal) of testing must not be greater than 68 lb/MWh-net.

iii. Determine the Net Hourly Heat Rate of the unit during all phases of testing.

b. Prior to conducting the testing of the future coal source, the permittee shall tune the unit to the future coal source for optimum performance while operating in Load Bin 5 using manual operation and intelligent combustion-controlled operation. The process of tuning the unit shall include three phases, manual control, hybrid between manual and intelligent combustion control operation, and intelligent combustion-controlled operation. The timing for this tuning phase shall not exceeded 30 days.

c. The protocol must include the following:

   i. The protocol must provide justification that the CO_2 limits will be affected by utilizing the future source of coal. At a minimum, such justification shall identify how the new source of fuel differs in characteristics from the existing source in terms of heating value, sulfur, and ash content and how these and other different characteristics will influence heat rate and compliance with CO_2 limits. Such justification may include but not be limited to evaluations of impact on CO_2 emissions using alternative procedures in Appendix G of 40 CFR Part 75 or other third party coal quality analysis programs that determine the unit performance output due to fuel quality.

   ii. The protocol must outline how the unit will be tuned to the future source of coal and how the third-party firm will be determining/evaluating that the unit has been optimized to the future source of coal. The protocol must provide duration for tuning and what parameter(s) will be evaluated to determine if the unit has been optimized.

   iii. The protocol must outline any contingency plans for extending the testing to meeting the emission data quality requirements and procedures for notifying the Director when implementing it.

   iv. Procedures for collecting, processing, reviewing and evaluating the emissions data.

   v. The protocol must identify the third-party and roles that the third-party will take overseeing the tuning of the unit, emission testing, and evaluation of the data collected.

   vi. The protocol must identify the credentials and qualification of the third-party overseeing this testing.

   vii. The protocol must conform to the testing requirements of Condition 3.3.1.

d. Within 60 days of completion of these tests, the permittee shall develop a test report which shall include the following:

   i. Hourly CO_2 emissions data of the baseline and future coal runs.

   ii. Hourly Heat Rate of the unit during the testing.

   iii. Readings of the unit parameters proposed to be used to determine when the unit is optimized on the future coal during the tuning and testing phases.

   iv. Evaluation of the emissions data collected during the baseline and future coal runs of the testing.

   v. Determination that the CAF of the proposed future coal is necessary.

   vi. Determination of the CAF to be applied to the CO_2 Limits for Load Bins 0 through 5 for this future coal source if applicable.

   vii. List the adjusted CO_2 limits for Load Bins 0 through 5 with the CAF applied.

   viii. List the date and time of when the unit continuously utilizes the new coal source.

e. Records of the testing, protocol, and results shall be maintained in accordance with Condition 3.3.1.

4.4. Recordkeeping Requirements

4.4.1. **Record of Monitoring.** The permittee shall keep records of monitoring information that include the following:

a. The date, place as defined in this permit, and time of sampling or measurements;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of the analyses; and

f. The operating conditions existing at the time of sampling or measurement.

4.4.2. **Record of Maintenance of Air Pollution Control Equipment.** For all pollution control equipment listed in Section 1.0, the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures.

4.4.3. **Record of Malfunctions of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0, the permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment during which excess emissions occur. For each such case, the following information shall be recorded:

a. The equipment involved.

b. Steps taken to minimize emissions during the event.

c. The duration of the event.

d. The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

e. The cause of the malfunction.

f. Steps taken to correct the malfunction.

g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.

4.4.4. Except for the limit for LB-0 in condition 4.1.1.a.i., the permittee shall determine the CO_2Weighted Average Limit for each calendar year in accordance with the following:

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

$\sum OPHL1_{LB-1}$ = Total Level 1 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)

$\sum OPHL1_{LB-2}$ = Total Level 1 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)

$\sum OPHL1_{LB-3}$ = Total Level 1 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)

$\sum OPHL1_{LB-4}$ = Total Level 1 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)

$\sum OPHL1_{LB-5}$ = Total Level 1 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)

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

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 in Condition 4.1.1.a.

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)

For times when a CAF is applied after the beginning of a compliance period, the permittee shall determine the Level 1 *CO_2 weighted avg* and Level 2 *CO_2 weighted avg* for the before the CAF and after the CAF using Equations 1 and 2 and the appropriate CO_2 limits for each of the load bins. The permittee shall use the following equation to determine the *CO_2 weighted avg* in lieu of Equation 3.

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.

$\sum OPHL2_{BCAF}$ = 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.

$\sum OPHL1_{ACAF}$ = 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.

Should the Administrator promulgate a revised CO_2 emission standard for new, modified, or reconstructed coal-fired EGUs under Subpart TTTT of 40 CFR 60 that are less stringent than the limitations in this permit, then the permittee is required to demonstrate compliance for that respective year to the revised Subpart TTTT standard. Should the revised Subpart TTTT standard be in terms that differ from the limit in this permit, the Director shall review and approve any method used to convert the limits into common terms.
[W.Va. Code §22-5-4(a)(4)]

Records of all calculations shall include the CO_2 weighted average limit and shall be maintained in accordance with Condition 3.4.1

4.4.5. Compliance Demonstrations: The initial compliance period shall begin on January 1, 2021 and end on December 31, 2021. Subsequent compliance periods shall follow thereafter. The compliance demonstration shall be performed no later than March 1 after the compliance period.

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.

Excluding CO_2 rates and generation that occurred while the unit was operating in Load Bin 0, the permittee shall conduct a compliance demonstration with the CO_2 Weighted Average limit as calculated from either Equation 3 or 4 in Condition 4.4.4. The compliance demonstration shall be determined by taking the sum of the valid hourly CO_2 rates in terms of lb divided by the sum of the net electricity generation (MWh net) in the respective compliance period for Load Bins 1 through 5. Excess CO_2 emissions is the amount of the actual annual average CO_2 rate above the CO_2 weighted average limit, if any.

Records of all demonstrations shall include actual annual average CO_2 rate and excess CO_2 emissions and shall be maintained in accordance with Condition 3.4.1.

4.4.6. The permittee shall maintain the following records:

a. Monitoring plan records under 40 CFR §75.53(g) and (h);

b. Operating parameter records under 40 CFR §75.57(b)(1) through (4).

c. The records under 40 CFR §75.57(c)(2), for stack gas volumetric flow rate;

d. The records under 40 CFR §75.57(c)(3) for continuous moisture monitoring systems;

e. The records under 40 CFR §75.57(e)(1), except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems;

f. The records under 40 CFR §75.58(c)(4), specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

g. The quality-assurance records under 40 CFR §75.59(a), specifically paragraphs (a)(1) through (12) and (15), for CEMS;

h. Records of data acquisition and handling system (DAHS) verification under 40 CFR §75.59(e).

i. Records of the calculations performed to determine the hourly and total CO_2 mass emissions (tons) for:

    i. Each operating month; and

    ii. Each compliance period, including, each 12-operating-month compliance period.

j. Records of the applicable data recorded, and calculations performed that are used to determine the EGU's net energy output for each operating month.

k. Records of the calculations performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

l. Records of the calculations performed to determine the weighted average CO_2 limits.

These records shall be maintained in accordance with Condition 3.4.1.

4.5. Reporting Requirements

4.5.1. The permittee shall prepare and submit an Annual Compliance report to the Director in accordance with Condition 3.5.3. by no later than March 1 following the end of each compliance period. Such report shall include the following and be certified by a responsible official.

a. The CO_2 Weighted Limits, Level 1 CO_2 Weighted Limits and the Level 2 CO_2 Weighted Limits, when applicable, as determined from Equations 1, 2 and 3 in Condition 4.4.4.

b. The current and next compliance period CO_2 Limit for each load bin adjusted in accordance with unit degradation adjustment factor provisions of Condition 4.1.1.c. and coal adjustment factor of Condition 4.1.1.d. when applicable.

c. The actual CO_2 rate of Load Bins 1 through 5 in terms of the limit for the compliance period.

d. The actual CO_2 rate of Load Bin 0 during the compliance period.

e. Excess emissions if any.

f. The percentage of valid operating hours during the compliance period.

g. The number of operating hours for each load bin as defined in Condition 4.1.1. during the compliance period.

h. The net energy output during the compliance period excluding operations occurring in Load Bin 0.

i. The gross energy output during the compliance period for Load Bin 0.

j. The annual average heat rate.

Records of such reports shall be maintained in accordance with Condition 3.4.1.

4.5.2. The permittee shall submit reports as required under Subpart G of 40 CFR Part 75 that are applicable to the permitted facility.

CERTIFICATION OF DATA ACCURACY

I, the undersigned, hereby certify that, based on information and belief formed after reasonable inquiry, all information contained in the attached ____________________________________, representing the period beginning _________________________ and ending _________________________, and any supporting documents appended hereto, is true, accurate, and complete.

Signature[1] ____ ____________________
(please use blue ink) Responsible Official or Authorized Representative Date

Name & Title ____________________________________ ____________________________________
(please print or type) Name Title

Telephone No. ________________________________ Fax No. ________________________________

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1 This form shall be signed by a "Responsible Official." "Responsible Official" means one of the following:

a. For a corporation: The president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

   (i) the facilities employ more than 250 persons or have a gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or

   (ii) the delegation of authority to such representative is approved in advance by the Director;

b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

c. For a municipality, State, Federal, or other public entity: either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of U.S. EPA); or

d. The designated representative delegated with such authority and approved in advance by the Director.

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west virginia department of environmental protection

Division of Air Quality
601 57th Street, SE
Charleston, WV 25304-2345
Phone 304 926 0475

Austin Caperton, Cabinet Secretary
dep.wv.gov

Pursuant to 45 CSR §13-8.8, the Division of Air Quality presents the

FINAL DETERMINATION

for the

Construction Permit

of

Longview Power LLC

Maidsville Facility

located in

Maidsville, Monongalia County, West Virginia

Permit Application Number: R13-3495

Facility Identification Number 061-00134

Date: December 23, 2020

Promoting a healthy environment.

BACKGROUND INFORMATION

Application No.:	R13-3495
Plant ID No.:	061-00134
Applicant:	Longview Power LLC
Facility Name:	Longview Power LLC
Location:	Maidsville
NAICS Code:	221112
Application Type:	Construction
Received Date:	June 1, 2020
Engineer Assigned:	Edward S. Andrews, P.E.
Fee Amount:	$1,000.00
Date Received:	June 1, 2020
Complete Date:	July 29, 2020
Due Date:	October 27, 2020
Applicant Ad Date:	July 17, 2020
Newspaper:	*Dominion Post*
UTM's:	Easting: 580.6 km Northing: 4,306.9 km Zone: 17
Description:	This action is to establish a carbon dioxide emission standard using the Best Standard of Emission Reductions (BSER) outlined in the Emission Guidelines of 40 CFR 60, Subpart UUUUa. This action is to establish a carbon dioxide emission standard using the Best Standard of Emission Reductions (BSER) outlined in the Emission Guidelines of 40 CFR 60, Subpart UUUUa (also referred to as the ACE Rule) for a Pulverized Coal-Fired Steam Generating Unit (PC-Boiler).

NOTICES AND PUBLICATION

Pursuant to 45 CSR §13-8.7. the West Virginia Division of Air Quality (DAQ) sent a copy of the advertisement, engineering evaluation, and draft permit to representatives of the applicant, and U.S. EPA Administrator, on October 8, 2020 via email. On October 9, 2020, the DAQ went to public notice in the above-noted newspaper with an "Intent to Approve" Longview Power LLC's permit to establish a carbon dioxide standard for their existing coal-fired electric generating unit (EGU) in Maidsville, Monongalia County, West Virginia. The Application, Draft Permit, Engineering Evaluation, and Interim Permit Review (IPR) File were made available at the following web link:

https://dep.wv.gov/daq/permitting/Pages/NSR-Permit-Applications.aspx

Under 45 CSR §13-9.1., the Director determined that holding a public meeting was appropriate for this application. On October 27, 2020 at 6:00 pm, the DAQ conducted a public meeting to provide information to the public regarding what was being permitted under this application and to take oral comments from the public. This meeting was held virtually to prevent the spread of COVID-19 in accordance with the WVDEP COVID-19 Policy. Notice for the public meeting was incorporated into the legal advertisement for the "Notice of Intent to Approve," the notice was provided to the U.S. EPA Administrator and applicant's representatives, and was sent to all subscribers of the Department of Environmental Protection's Enhanced Mailing List on October 9, 2020.

Comments on the Draft Permit were accepted until 5:00 PM on November 9, 2020.

This Final Determination summarizes the comments received on the draft permit, includes responses to the comments, and documents any actions taken or changes made in response to the comments regarding Permit Application R13-3495.

COMMENTS ON THE DRAFT PERMIT

During the public comment period, comments were received from the parties listed below. Each is briefly summarized here. All original comments and associated DAQ responses are in the public file available at https://dep.wv.gov/daq/permitting/Pages/NSR-Permit-Applications.aspx

U.S. EPA's Comments

The DAQ did not receive any comments from the U.S. EPA Administrator or his/her representative during the public comment period.

Written Comments

During the comment period, the DAQ received two comment letters supporting the application and draft permit from the West Virginia Attorney General Mr. Patrick Morrisey; and second one from the West Virginia congressional delegation, which was signed by Congressman Mr. David McKinley, Congresswoman Ms. Carol Miller, Congressman Mr. Alex Mooney, and Senator Ms. Shelley Moore Capito. In addition to these two letters of support, the DAQ received a written copy of Congresswoman Miller's comments made during the October 27, 2020. These letters do not require any response.

The DAQ received two sets of comment emails from two separate organizations (Mon Valley Clean Air Coalition and the Sierra Club West Virginia Chapter). Also, the DAQ received five emails from individuals. The following table was developed to link specific responses to individual commenters.

Commenter No.	Name of Organization	Name of Commenter	Submittal Date
1	N/A	Joe Robinson	October 26, 2020
2	N/A	Bill Reger-Nash	October 28, 2020
3	N/A	Betsy Lawson*	October 31, 2020
4	N/A	Stephen Lawson*	November 1, 2020

5	N/A	Stephen Lawson*	November 1, 2020
6	Sierra Club WV	James Kotcon	November 9, 2020
7	Mon Valley Clean Coalition	Duane G. Nichols	November 9, 2020

** Stephen Lawson and Betsy Lawson submitted identical comments three times from two different email addresses.*

Comment #1 from Commenter 2, 3,4,5, 6, and 7

Several commenters commented that the permit would allow Longview Power to emit more carbon dioxide emissions. One commenter, Comment #6, specifically noted that the unit degradation factor is compounding the bin limits and the UDAF should only be based on the base year. The DAQ assumed that the other comments were implying this in their remarks as well.

DAQ's Response to Comment #1

This permit is to establish a carbon dioxide emissions standard in accordance with the emission guidelines that EPA established under the ACE Rule.[1, 2] Under this regulation, the carbon dioxide standard must be established in the terms of pounds (lbs) of carbon dioxide per unit of energy output from the emissions unit.[3] The limits in Permit R13-3495 do not relieve Longview Power of the responsibility to comply with all of the requirements established in R14-0024G which includes a limit on the amount of heat energy that can be burned in their electric generating unit (EGU). This heat energy input limit indirectly caps Longview's carbon dioxide emissions on a mass basis. However, this indirect cap is not in the form of the CO_2 standard as set forth in the emissions guidelines[4] and, therefore, is not acceptable. The permit does not replace or increase the heat input restriction in Permit R14-0024G.[5]

The ACE Rule requires evaluation of seven heat rate improvement technologies that EPA determined to be the Best System of Emission Reductions (BSER) for existing coal-fired EGUs.[6] If the evaluation of the BSER technologies had determined that there were additional heat rate improvement (HRI) opportunities through the implementation of feasible BSER technologies, then there would have been a corresponding reduction in the standard from the baseline. For the Longview Power BSER evaluation, that was not the case, as there were no additional HRI opportunities available. Based on DAQ's review of Longview Power's evaluation of the BSER candidate technologies identified in the federal ACE emission guidelines, Longview Power has fully implemented six of the seven BSER candidate technologies and practices. The only BSER

[1] EPA-452/R19-003, 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, June 2019, Page 1-9
[2] 84 FR 32520, Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations, July 8, 2019, page 32521.
[3] 84 FR 325555. (July 8, 2019)
[4] 40 CFR §60.5755a(a)(1).
[5] Permit R14-0024G, Condition 5.1.1.a.
[6] 84 FR 32537. (July 8, 2019)

technology not currently installed is the use of variable frequency drives (VFD) on some facility equipment; however, the technology currently being utilized by Longview Power is equivalent to or better than VFDs in this application, in the opinion of the DEP. Enumeration of the reasons that the Variable Frequency Drives (VFD) were not feasible is provided starting on page 10 of the Engineering Evaluation. Therefore, there is not a corresponding reduction to the CO_2 emission rate at Longview Power that is consistent with the anticipated HRI ranges provided in Table 1 of the federal ACE emission guidelines.[7]

This unit has been in service for less than ten years and most of the key pieces of equipment have not undergone a major maintenance outage. The unit will degrade (unit heat rate performance will decay) over time with or without implementing these HRI technologies. Lacking unit specific data, Longview Power proposed a decay and recovery rate less than the decay rate (decay curve) of similar units operating in the same regional transmission organization (PJM). The DAQ's detailed evaluation of the proposed decay and recovery curve are provided in Regulatory Applicability Section of the Engineering Evaluation. The U.S. EPA recognized degradation of equipment in its discussion of the BSER candidate technologies, such as the blade path upgrade discussion when it states "(t)hese improvements in new turbines can also be utilized to improve the efficiency of older steam turbines whose efficiency has degraded over time."[8]

Regarding the calculation of the standard of performance for each load bin based on the mean plus two times the standard deviation, statistically speaking, 95% of the data will fall within this range. This is important especially for load bins LB-1 through LB-4 due to the smaller amount of data available in the baseline period for these load bins because Longview Power has operated over 90% of the time in LB-5. The use of the standard deviation therefore accounts for normal operational and measurement variability. It is worth noting that measurement accuracy alone can account for more variation than calculating the standard as the mean plus two times the standard deviation. Additional discussion on this topic was provided in the engineering evaluation and in DAQ's Response to Comment #12 regarding a suggested alternative approach.

The permit allows for a 0.4% increase per year in the standard in terms of pounds per megawatt hour over 5 years because of the degradation of the emissions unit between maintenance outages. The permit also provides for a decrease of the standard of 0.7% every fifth year to account for the efficiency recovered during reconditioning/repairing degraded equipment during major maintenance outages. The compounding as referred to by Commenter # 6 is applied in the same manner for the degradation (increase the bin limits) and recovery (decreasing the bin limits) years and is capped in 2046, as shown in Appendix A of the Engineering Evaluation. For additional explanation of degradation, please also refer to the DAQ's Response to Comment #14 and to Mr. Kotcon's Comment #6 for additional discussion concerning the Unit Degradation Adjustment Factor (UDAF).

[7] 84 FR 32537, (July 8, 2019), Table 1 - Summary of Most Impactful HRI Measures and Range of Their HRI Potential (%) by EGU Size, page 32537.
[8] 84 FR 32539 (July 8, 2019)

Comment #2 from Commenter 2

Please do not allow Longview to spew more toxic emissions into our air, waterways, and ultimately our soil.

DAQ's Response to Comment #2

This permit only establishes a carbon dioxide emission standard for Longview Power's EGU. The limitations imposed in this permit do not alter Longview Power's obligation to comply with all the limitations within Permit R14-0024G. Permit R14-0024G requires Longview Power to control its release of hazardous air pollutants (HAPs) to levels below major source thresholds (e.g., total HAPs less than 25 tons per year).

Comment #3 from Commenters #3, 4, 5, and 7

Several comments questioned the legal grounds to develop and establish a carbon dioxide standard in accordance with the ACE Rule. Also, the timing to issue a permit with such limits in it.

DAQ's Response to Comment #3

Longview Power elected to move forward and develop a carbon dioxide emission standard for their unit in line with the Emission Guidelines set forth in the ACE Rule without a mandate developed and approved by the State of West Virginia. Longview Power elected to proceed using the Rule 13 Permitting Process (45 CSR 13) to make this carbon dioxide emission standard enforceable and permanent. The authority for 45 CSR 13 is provided under West Virginia Code § 22-5-11, *Construction, modification or relocation permits required for stationary sources of air pollutants*.

Owners/operators of stationary sources can submit a request to obtain a permit to establish enforceable terms on a voluntary basis under Rule 13, Section 5.5.[9] Longview Power initially applied to have their R14-0024G permit administratively updated. The DAQ determined that using the administrative update process[10] did not provide public participation and did not allow the DAQ the authority to establish reasonable conditions which would be necessary to completely account for all of the requirements for developing a CO_2 standard and determined that a construction permit application should be submitted. There is no provision within 45 CSR 13 that allows the DAQ to deny such permit unless the permitted source will violate applicable emissions standards or interfere with attainment or maintenance for an applicable ambient air quality

[9] 45 CSR 13, Permits for Construction, Modification, Relocation and operation of Stationary Sources of Air Pollutants, Notifications, Requirements, Administrative Updates, Temporary Permits, General Permits, Permission to Commence Construction, and Procedures for Evaluation, 45 CSR 13-5.5.
[10] 45 CSR §13-4.

standard.[11] Under West Virginia Code § 22-5-6, the violation of a permit is subject to the same enforcement remedies as the violation of a rule.

The West Virginia State Code was amended during the 2020 Legislative Session which requires the DAQ to submit a complete or partial state plan to the U.S. EPA by September 1, 2020 for one or more of the EGU facilities that voluntarily were prepared to move forward with a permit application to limit CO_2 emissions for one or more of their EGUs.[12] Even without a specific mandate, Longview Power has a right under DAQ rules to request a voluntary permit to establish carbon dioxide emission standards and the agency has been tasked by the West Virginia Legislature to process such a request in a manner that can be used to develop a state plan to fulfill the State of West Virginia's obligation to comply with the ACE Rule.

West Virginia Code and Rule 13 require the DAQ to render a final decision on each application within 90 days once the application is determined to be complete.[13, 14] Thus, the DAQ is obligated to make a final decision on all complete applications in a timely fashion.

In this permitting action, the DAQ is attempting to comply with the timelines outlined in the West Virginia Code for acting on permits and as a prerequisite for submitting a timely state plan to the U.S. EPA.

Comment #4 from Commenters #3, 4, and 5

"Doubtless Longview has the provision that permits extra emissions when not operating at full capacity clearly in mind. This, as inevitably coal energy will become less profitable as alternative energy becomes more so, as it already is. On top of this economic crutch, an increase of 0.4% per annum after 20 years would allow an increase to 108% from the starting point, more if compounded - instead of less, as the future habitability (and economic stability) of the world requires."

<u>DAQ's Response to Comment #4</u>

U.S. EPA allowed/granted the states flexibility in establishing CO_2 standards by not providing a model rule or guidance on the ACE Rule.[15] U.S. EPA has made it clear to the states that the standard must include all periods of operation, which include startup, shutdown, and non-base load operating times. The Longview Power EGU was designed to operate in a base load operation mode, and currently operates as a base load unit. While Longview Power would prefer to operate as a base load unit, its most efficient mode, the DAQ recognizes that due to the economic

[11] 45 CSR 13, Rule 13, 45 CSR §13-5.7.
[12] Chapter 22 Environmental Resources, Development of State Plan Relating to Carbon Dioxide Emissions from Exiting Fossil Fuel-Fired Electric Generating Units. West Virginia Code §22-5-20.
[13] W. Va. Code § 22-5-11(d).
[14] 45 CSR §13-5.7.a
[15] 84 FR 32521. (July 8, 2019)

dispatch of units by PJM, there are limitations on Longview Power's ability to operate as a base load unit long-term.

Longview Power is a single merchant power plant operating in the PJM regional transmission organization (RTO). PJM Interconnection is a RTO that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Longview Power is compensated for its generation based on wholesale electricity pricing rates, which are set by PJM for each operating day. Also, PJM controls or determines how much electricity Longview Power will generate each day. This supply and demand process sets the pricing based on the amount of electricity needed to maintain the electric grid each day. Longview Power cannot control the pricing or the demand for its electricity each operating day, that is the role of the RTO.

The DAQ believes that the load bin approach accounts for the unit's efficiencies at all load ranges and allows the standard to be constraining regardless of which operating load the unit is operating within. The first issue with setting a single limit based on the average of the carbon dioxide over all operating loads is that the standard would clearly not be constraining at the unit's most efficient operating load. The second is that the standard must be achievable for all operating modes.

Establishing specific conditions to account for unit degradation is not unheard of in the New Source Review Program.[16,17] The Virginia Department of Environmental Quality (VA DEQ) established heat rate and carbon dioxide limits for the Chickahominy and Greenville Power Stations in their permits. These conditions allowed for the incremental increases in the unit's heat rate and carbon dioxide rate limits over time. The incremental increase that VA DEQ permitted was approximately 0.25% annually for the Chickahominy Power Station and 0.31% annually for the Greenville Power Station. Both facilities are combined cycle combustion turbine EGUs.

As noted earlier and in the engineering evaluation, Longview Power's EGU operates in the PJM's RTO market. The daily pricing is based on supply and demand for electricity each day, and accounts for the cost from lower cost generators – natural gas, hydro, solar and wind operators. Economics, the daily pricing and the unit's operating cost, will ultimately determine if the unit will operate.

Please refer to DAQ's Response to Comments #1, #14, and Mr. Kotcon's Comment #6 for additional explanation concerning the unit degradation adjustment factor.

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[16] Virginia Department of Environmental Protection, Construction Permit for Chickahominy Power Station – Registration No. 52610, June 24, 2019, Condition 8 and 35 on pages 4 and 13.
[17] Virginia Department of Environmental Protection, Construction Permit for Greenville Power Station – Registration No. 52525, June 17, 2016, Condition 8 and 40 on pages 4 and 13.

Comment #5 from Commenters #3, 4, and 5

"Moreover, Longview included years of operation without their current more efficient emissions controls when proposing their averaged emissions, ensuring the ceiling would be well above their current emissions. This means that they are applying to emit above their current pollution levels, on top of the proposed increase. What is the point of having installed such, to propose to run them at 'half-cock' - apart from selling electricity more cheaply to their customers outwith West Virginia {sic}, which will suffer the poorer air quality, but where the permit would come from."

DAQ's Response to Comment #5

The selected baseline period is representative of the additional improvements that Longview Power has made within the scope of the BSER candidate technologies in the emissions guidelines. Longview also made additional improvements which were outside of the scope of BSER candidate technologies during the selected baseline period.

Of the BSER technologies, only the neural network and intelligent sootblowing technologies can be turned off or not utilized. The intelligent sootblowing systems are programed to activate the sootblowers at the target section of the unit without any action or acknowledgement from an operator. To prevent the generator from tripping offline, operators usually disable the intelligent sootblowing systems when the unit is operating at low loads that do not support sootblowing operations or program the system such that it is not activated at low steam production conditions.

Please also refer to DAQ's Response to Comment #1, #11, Ms. Rosser's Comments, and Ms. Barbor's Comments for additional responses on increases emissions.

Comment #6 from Commenters #3, 4, and 5

"How much of this does the taxpayer cover?"

DAQ's Response to Comment #6

Longview Power is a merchant power plant and is not regulated by the West Virginia Public Service Commission. DEP does not regulate how Longview is financed.

Comment #7 from Commenter #7

"Now the WV-DEP is proposing more concessions to Longview Power LLC so as to permit them to pollute the environment, even more than otherwise. How in God's name can you look at yourself in the mirror if you are the enabler of increased pollution? The WV-DEP has a responsibility to DECREASE pollution, NOT INCREASE IT, where have you been? In other words, who is running our state government?"

DAQ's Response to Comment #7

Please refer to DAQ's Response to Comments #1, #14, and Mr. Kotcon's Comments #6 and #7.

Comment #8 from Commenter #7

Because this draft permit would establish excessive and unnecessary carbon dioxide emissions, all other emissions will also be increased. The intent of climate change regulations is to reduce all greenhouse gases. Even the water vapor and the particulates contribute to this, so must be considered.

This draft is premature. There is no current level of regulation or control. In fact, the operation of Longview isn't needed, not necessary, since our PJM has plenty of generation. This company is not operating in as a public service, rather as a private operator for private gain, i.e. to maximize profits. The WV-DEP has no such mandate, rather you should function in the public interest.

DAQ's Response to Comment #8

U.S. EPA specified in the ACE Rule that the pollutant to be regulated is greenhouse gases (GHG) in the form of carbon dioxide and provided its justification for doing so by stating:

> The air pollutant regulated in this final action is GHGs. However, the standards in this rule is expressed in the form of limits solely on emissions of CO_2, and not the other constituent gases of the air pollutant GHGs. The EPA is not establishing a limit on aggregate GHGs or separate emission limits for other GHGs (such as methane (CH_4) or nitrous oxide (N_2O)) as other GHGs represent significantly less than one percent of total estimated GHG emissions (as CO_2equivalent) from fossil fuel-fired electric power generating units. Notwithstanding the form of the standard, consistent with other EPA regulations addressing GHGs, the air pollutant regulated in this rule is GHGs.[18]

Other emissions from Longview Power will not be increased because of this action. Emissions of other pollutants are regulated under Permit R14-0024G. Longview Power must continue to adhere to those other emission limitations regardless of this action.

The DAQ is responsible for regulating air pollution from EGUs and has no authority for regulating or approving electrical generation. One of the primary entities responsible for regulating and approving electrical generation is the Federal Energy Regulatory Commission

[18] 84 Fed. Reg. 32534 (July 8, 2019).

(FERC), an independent agency that regulates the interstate transmission of electricity, natural gas, and oil.

Longview demonstrated that the feasible BSER technologies have already been installed or implemented in accordance with the federal emission guidelines. The emission guidelines are focused on reducing carbon dioxide emissions from existing coal-fired EGUs. Longview Power meets the definition of an affected facility.

In the Regulatory Impact Analysis (RIA) for the ACE Rule, U.S. EPA acknowledged that the emission guidelines are not expected to result in any additional reductions in CO_2 emissions from units currently operating with a heat rate of less than 9,773 Btu/kWh.[19] U.S. EPA's own data indicates that Longview Power's unit heat rate is below this threshold.[20] The DAQ did not identify any additional improvements based on the BSER that would provide any additional heat rate improvements within the U.S. EPA's expected heat rate improvement potential ranges for the Longview Power unit. The commenter did not provide any specific HRI that the DAQ overlooked to suggest that the standard should be lower than proposed.

Neither the Clean Air Act nor the Air Pollutant Control Act[21] requires that the emission source or emission unit be operated as a public service.

Comment #9 from Commenter #6

1) The Engineering Evaluation (EE) for the draft permit indicates that the limits were established using annual emissions averages, plus two Standard Deviations. I have not found anything in the federal ACE rule nor in the proposed 45-CSR-44 state rule to require that either a 3-Standard-Deviation or 2-Standard Deviation variation be considered. Incorporation of statistical variability is appropriate to reflect random, uncontrollable variability in the production process or in measurement of the emission rate. The EE discusses variation in hourly and monthly emission rates. Because the proposed standard is based on annual average emissions variations over shorter time periods are irrelevant. The annual average emission rates at Longview are a compilation of thousands of individual measurements over the year and so, address random variability over shorter time frames. The variation in annual performance over time largely reflect matters, such as technology upgrades, ongoing maintenance schedules and operating loads that are within the control of the operator and are not random events. Other variables, such as variation in annual average cooling water temperature, that are not in LVP's control and could theoretically affect the annual average emission rate are ordinarily quite small and have not been separately determined by WVDEP. The historic emission rates at Longview (as measured and reported by the operator to EPA) demonstrate that the plant, even at

[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, June 2019, Page 1-16.
[20] Nation Electric Energy Data System v6, https://www.epa.gov/sites/production/files/2020-10/needs_v620_10-05-20_0.xlsx, October 5, 2020.
[21] West Virginia Code Chapter 22-5.

10 years of age, has sustained and maintained rolling annual average emission rates below 1750 lb/MWh (gross) or 1925 lb/MWh (net).

DAQ's Response to Comment #9

Under the ACE Rule, U.S. EPA specifically intended the details of determining emission rates and standards development methods be under the purview of states.[22] Indeed, Congress has expressly provided that the U.S. EPA must permit states to take into consideration a source's remaining useful life, among other factors, when applying a standard of performance to a particular source.[23] U.S. EPA specifically acknowledges that the states are better suited to develop those standards and states should take into consideration source-specific factors, such as the EGU's past and projected utilization rate, maintenance history, and remaining useful life (among other factors), when develop such standards.[24]

Since every unit operates differently, a single hard-coded approach is not feasible. A permitting agency must consider the historical emission rates from each unit to determine at which levels the unit can be feasibly and most efficiently operated. This historical performance includes operational variation including random, unanticipated, and un-forecastable factors, such as variation in the annual average cooling water temperature. The economics and profitability of a unit are not within the scope of the agency's mission.

Regarding the calculation of the standard of performance for each load bin based on the mean plus two times the standard deviation, statistically speaking, 95% of the data will fall within this range. This is important especially for load bins LB-1 through LB-4 due to the smaller amount of data available in the baseline period for these load bins because Longview Power has operated over 90% of the time in LB-5. The use of the standard deviation therefore accounts for normal operational and measurement variability. It is worth noting that measurement accuracy alone can account for more variation than calculating the standard as the mean plus two times the standard deviation. Additional discussion on this topic was provided in the engineering evaluation and in DAQ's Response to Comment #12 regarding a suggested alternative approach.

Comment #10 from Commenter #6

These data (See Figure One, below) also show that, after initial startup issues were resolved, the emission rate improved over time (as some – but by no means all - of the recommended HRI technologies were adopted) rather than degrading. It should also be understood that these rates include operation in all Load Bins and were achieved at a time when Longview's operator was under no obligation to maintain a specific emission limitation and may have found it to be economically rewarding to operate in a fuel-inefficient manner. Thus,

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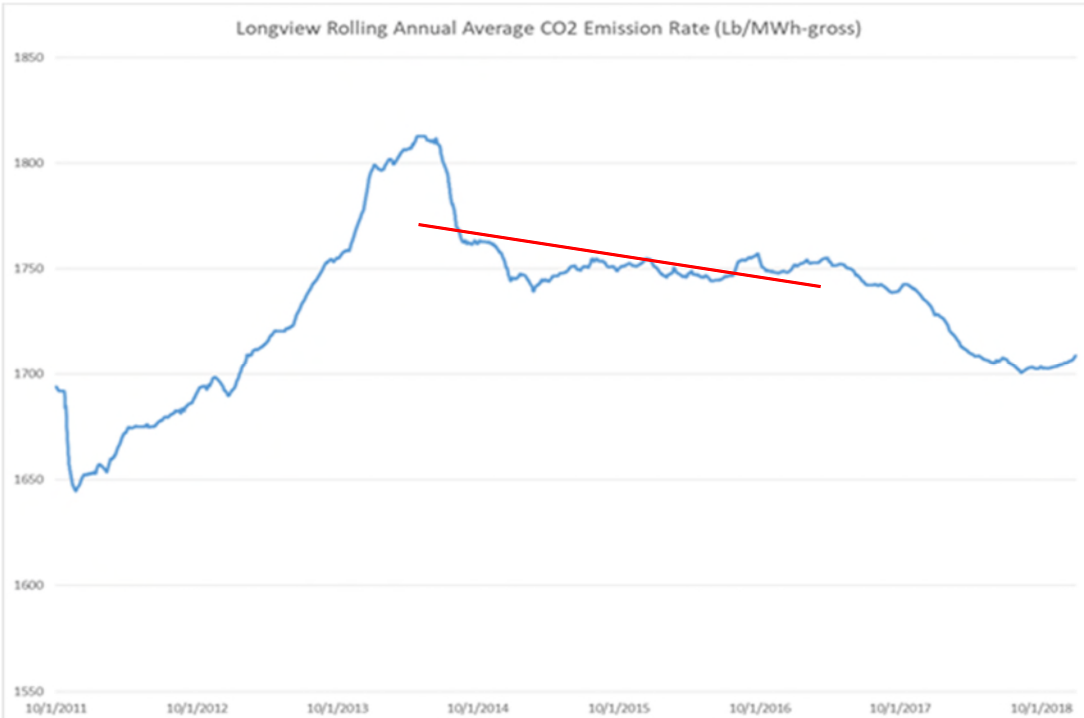
[22] 84 FR 32521-32523 and 32530. (July 8, 2019)

[23] 42 U.S.C. 7411(d)(1).

[24] 84 FR 32536.(July 8, 2019)

instead of seeking improvements in performance and reductions in emissions, the proposed limits in the draft permit would allow significant increases in greenhouse gas emissions.

Figure One from Commenter #6. Longview Rolling Annual Average Emission Rates[25]



DAQ's Response to Comment #10

It is always to the operator's economic advantage to operate in the most fuel-efficient manner possible, as fuel is the largest operational cost for any fossil-fuel EGU. Certain combinations of operating conditions may exist that compel an operator to temporarily operate in an inefficient manner, but these conditions are acutely transitory, unsustainable, unexpected, and would have little impact on the long-term average CO_2 emission rate. Longview is still a relatively new unit which has not experienced its first major maintenance outage. Over time the unit will degrade, even with all appropriate maintenance, similar to a new car which over time operates less efficiently, even with all scheduled maintenance.

Please also see the DAQ's Responses to Comment #1, Ms. Lawson's Comments, and Ms. Rosser's Comments concerning the increase in emissions and the DAQ's Responses to Comment #14, #15, Ms. Barbor's Comments, and Mr. Kotcon's Comments #6 and #7 concerning degradation.

[25] Source: emissions data reported by Longview to USEPA www.ampd.epa.gov.

Comment #11 from Commenter #6

The use of 2014-2018 data to calculate the average and Standard Deviation inflates the emissions because 2014 occurred before installation of certain HRIs, such as the Neural Network Upgrade (June 2015) and the Intelligent Combustion (Fall 2018). It certainly inflates the estimate of Standard Deviation because it includes higher rates from those years with lower rates in 2019-2020 in that calculation, Indeed, because of the increased Standard Deviation that results, the inclusion of the lower emission rates in 2017 and 2018 actually increases the proposed emission rate over what it would have been had only the pre-modification date (2014 to 2016) been employed. It is inappropriate to establish a standard for operation with HRIs by including emission data from years of operation without those HRIs. Yet the EE clearly states (page 22, repeated on page 23) that:

"the entire baseline period was used for developing the standards for all of the bins".

The most appropriate approach would be to estimate the variability in emissions based solely on 2019 and 2020 data, because those are the only data for emissions with all HRIs in place. The mean and the variance can be estimated from the hourly emissions data from those years. Thus, the mean for all emissions in 2019 should be 1899 lbs/MWh or lower.

<u>DAQ's Response to Comment #11</u>

The baseline period ultimately selected to calculate the standard is 2016 through the second quarter of 2020 because all BSER HRIs were installed prior to this timeframe, specifically so the standard was calculated after the BSER HRIs were implemented. The comment that 2014-2018 data was used to calculate the standard and the commenters assertion that the standard was inflated as a result are incorrect.

Intelligent combustion HRI is not identified as a BSER candidate technology in the emission guidelines and therefore has no bearing on the selection of the baseline period. See DAQ's Response to Comment #12 for further explanation.

The DAQ's decision to retain the baseline period as 2016 through the second quarter of 2020 remains appropriate for the reasons previously identified in the Engineering Evaluation. Please also refer to the DAQ's Responses to Comment #1 above and Comment #12 below for additional discussion concerning the standard deviations for the baseline period.

Comment #12 from Commenter #6

Furthermore, the 2019-2020 data represent a mean over hours of operation that include all of the operating loads. Figure 8 of the EE indicates that Longview operated at something less than 90 % of the time, and Figure 12 suggests that the plant was operating in Load Bin 0 (<40 % capacity) approximately 50-100 hours in 2019 when would have the highest emissions rates, and had a significant number of operating hours in Load Bins 1-4 in 2019-2020. Table 4 *(page 23) implies that emissions limits were calculated using emissions data for the respective Load Bins, however, those means do not match the levels in the draft permit. It is inappropriate to establish a standard for operation with HRIs during periods of peak performance (full capacity loads) by including emissions data from hours of operation at lower unit loads, when emissions per MWh are higher.*

DAQ's Response to Comment #12

As noted by the commenter, 1st and 2nd Quarters of 2020 contains emissions data that increase the number of data point for the lower load bins. Longview Power and the DAQ added this additional time to the base period to increase the amount of data for the lower load bins which was needed to allow the use of a cumulative approach to refine the data with an acceptable standard deviation for each of the bins. This additional data by itself would not be sufficient in developing a limit for these lower bins, which will be explained in further detail in this response.

The use of load bins allows the DAQ to evaluate the unit's emission data and limit the variability to load bins. Furthermore, the standards or limits are weighted averages for each load bin based on the number of hours operated in a particular load bin and the established limit for that load bin. To clarify, if the unit operated in LB-5 (i.e., full capacity load range) 100% of the time, the lower load bin limits would have no effect on the LB-5 limit.

The DAQ was tasked in this review process to develop and establish a realistic performance standard that is both constraining and achievable. Looking at a shorter baseline period limits the amount of data (number of data points) to be considered in the lower load bins. Such data is needed for the approach that the DAQ used to develop the standard.

The following table was developed using 2019 unit data through 2nd Quarter 2020 unit data as suggested by the commenter.

Table 1 Evaluating Longview Power Emissions Data from 2019 through 2nd Quarter of 2020[26]		
	Shorten Baseline Period of 2019 to 2020 2nd Qtr.	Baseline Period of 2016 to 2020 2nd Qtr.
	CO_2 Rate (lb/MWh-net)	
Average Rate for LB-1	2140	2183
Count for LB-1	11	24
Standard Deviation of LB-1	96	22
Commenter's Suggested Limit for LB-1*	2333	2,231
Average Rate LB-2	2038	2050
Count for LB-2	11	25
Standard Deviation of LB-2	54	29

[26] Data Source used to determine the values in the table is Clean Air Markets Division of Longview Power, ORIS 56671, Quarter 1, 2, 3, 4 of 2019, and Quarter 1, 2, and 3 of 2020. U.S. EPA Field Audit Checklist Tool Version 1.6.0.3 was used to obtain these data set from CAMD.

Commenter's Suggested Limit for LB-2*	2146	2108
Average Rate for LB-3	1993	1998
Count for LB-3	17	34
Standard Deviation of LB-3	36	26
Commenter's Suggested Limit for LB-3*	2065	2050
Average LB-4	1952	1966
Count for LB-4	18	38
Standard Deviation of LB-4	32	18
Commenter's Suggested Limit for LB-4*	2015	2002
Average Rate for LB-5	1893	1916
Count for LB-5	18	42
Standard Deviation of LB-5	21	21
Commenter's Suggested Limit for LB-5*	1935	1958

* The bin limit was calculated by adding the average for the bin to two times the standard deviation for the bin.

As shown in Table 1 above, for Load Bins 1-4, the commenter's suggested approach for calculating the standard is based on fewer data and results in a less stringent standard for those load bins. The average rate for each bin using the shorter period is lower than the average rate based on the selected baseline used to develop the proposed standards. This shorter period does not reduce or minimize the variability in the hourly rates by bin, which is indicated in the standard deviation in the above table except for Load Bin 5. The 95% confidence level of the data for the shorter period ranges from 10.4 for Load Bin 5 to 64.7 for Load Bin 1.

The 95% confidence level from the approach used in the permit ranges from 6.0 (for Load Bin 4) to 12.1 (for Load Bin 2). This approach gave the DAQ a reasonable level of confidence that future carbon dioxide emissions rates should comply with the permit over the whole normal operating range of the unit. The 95% confidence level for the shorter baseline period is almost nonexistent in the lower to mid operating ranges. For LB-1 with the shorter baseline period, the standard deviation was determined to be four times higher than the standard deviation determined using the four and half years of data for the baseline period with the DAQ approach.

Due to these low confidence levels using the data from the shorter baseline period, the method used to account for the whole or nearly the whole population of the data (2*SD) in the load bin limits would need to be revisited as well. Two times the standard deviation (critical value) would only account for the whole population of the data for Load Bin 5. 2*SD does not account for the highest rate from the population. To account for this issue, the individual bin limits for the normal operating range would be raised even higher than listed in the above table.

The processed data using the suggested shorter baseline does not minimize the variability in the data. The standard deviation from the shorter baseline period ranged from a low of 21 for LB-5 to a high of 96 for LB-1. DAQ used a 12-month rolling average to refine the monthly data to yield a standard deviation that ranged from a low of 18 for LB-4 to a high of 29 for LB-2.

Another approach suggested by the commenter that might seem appropriate is the use of the highest reading from each bin using the reduced baseline period. These readings are presented in the following table.

Table 2. The Highest Rate by Load Bin from 2019 through 2nd Quarter of 2020[27]			
Load Bin No.	Commenter's Suggested Limit from Table 1	Highest Rate from 2019-2020 2nd Qtr	Highest Rate from 2016 to 2020 2nd Qtr
	lb/MWh- Net	lb/MWh- Net	lb/MWh- Net
Highest Reading for LB-1	2,333	2,373	2,229
Highest Reading for LB-2	2,146	2,093	2,096
Highest Reading for LB-3	2,065	2,038	2,036
Highest Reading for LB-4	2,015	2,031	1,998
Highest Reading for LB-5	1,935	1,920	1,942

The suggestion of only using the narrow period that indicates a better CO_2 performance from the unit is not a reasonable alternative for developing a limit or standard. This shorter baseline would raise another issue in establishing a compliance period that is representative of the developed standard. Load Bin 4 and 5 could be set on an 18-month basis because there were data in every month of the shorter baseline period for these two load bins. Load Bin 3 would only have 17 data points, which is not enough for developing an 18-month standard/limit. Bins 1 and 2 have less than 12 data points which is not enough to develop an annual standard. The method(s) used to develop bin limits and/or standard(s) must be representative of the time frame for the compliance period.

By using 4.5 years of data, the baseline period contained enough data in each load bin to use a cumulative approach – taking the monthly data and determining a rolling 12-month average for each bin. Second, the DAQ approach did not exclude or omit any of the emissions data from the baseline period. In selecting an averaging period using the shorter baseline period, the compliance period would have to be on a quarterly basis.

The use of two times the standard deviation (2*SD) for each bin in establishing the bin limit uses the historical variability in the data to create the margin of compliance. The average plus 2*SD covers or accounts for the highest rates of each of the load bins without adding any additional margin of compliance. Thus, Longview Power cannot claim that the bin limits are not appropriate or do not account for the variability of the CO_2 emission rate by each bin.

The reduced baseline period would not result in a more constraining standard than the limit proposed in the permit, except for Load Bin 5. The bin limits developed in the draft permit are less than the limits from the shorter baseline period. The DAQ looked at several different

[27] Data Source used to determine the values in the table is Clean Air Markets Division of Longview Power, ORIS 56671, Quarter 1, 2, 3, 4 of 2019, and Quarter 1, 2, and 3 of 2020. U.S. EPA Field Audit Checklist Tool Version 1.6.0.3 was used to obtain these data set from CAMD.

approaches or other methods to develop either bin limits and/or the standard, which yielded nearly the same results as those developed using the shorter baseline period suggested by the commenter.

Tables of the monthly rates and descriptive statistics based on the unit's emission data from 2019 through 2nd Quarter 2020 can be found in Appendix A of this final determination.

Comment #13 from Commenter #6

Section 4.1.1.b. The provision that the plant can operate for up to 180 days at the Level 2 emissions limits, and "shall be deemed approved…" places the burden on WV-DEP to affirmatively verify if the incident qualifies as a Level 2 event and provides no means for the public to determine whether WV-DEPs determinations are correct or to challenge any WV-DEP determinations. The provisions give too much incentive to Longview to declare such events for relatively minor problems, problems that the O&M practices should prevent and too much of an administrative burden of WV-DEP. There is no limit in the draft permit on how often a Level 2 event might be declared, nor whether overlapping events might allow Longview to operate indefinitely with Level 2 limits. We recommend that the hours of Level 2 operation be restricted to less than 8 hours per event (so as to allow for shut down of the unit) to prevent unwarranted emissions from running at Level 2 indefinitely.

DAQ's Response to Comment #13

The 180-day allowance for Level 2 events allows LVP to maintain critical grid-support operations in the event of major equipment failure should the unit be called upon by PJM to maintain operations. The purpose of the Level 2 limit is to encourage Longview Power to develop a plan, prepare for repairs, and coordinate with the RTO to minimize the time the unit operates at Level 2. Requiring DAQ approval could prevent the unit from operating during times of critical load generation required by the RTO or require the RTO to call up less efficient unit(s) that would not normally operate to make up the difference in loss generation.

The Level 2 provisions should encourage Longview to identify these impaired operations timely and complete repairs in a timely fashion verses operating the unit impaired using the margin of compliance in hopes the unit can make it to the next major maintenance outage without causing a exceedance in the standard. Major maintenance outages are normally scheduled every 5 or 6 years.

The suggestion made by the commenter does not encourage operators to identify the issue that is impairing their unit operations. Instead, the suggestion would encourage the operator to fix the unit to point that the unit can be operated at an impaired performance level, not inform the DAQ of the impaired operations and make required repairs at the next planned major outage, which may be years down the road. The Level 2 provisions allow the unit to still generated revenue for the operator while waiting for resources to be made available to make the repairs.

After consideration, the DAQ determined that the suggested time frame of 8 hours for a Level 2 (impaired operation) is unreasonable. For an annual compliance period, a single event of 8 hours would not affect compliance unless that impairment or damage increased the unit's heat rate by more than 10%. The suggestion of setting a maximum duration of operating at Level 2 was not adopted into the permit.

Comment #14 from Commenter #6

Section 4.1.1.c. The Unit Degradation Adjustment Factor (UDAF) allows a 0.4 % increase per year, with a 0.7% recovery every five years. These values appear to be based on Longview's analysis of historic data for similar plants within the region. Since none of these units are under any obligation to maintain a maximum emission rate, this data only tells us what has been done in the absence of a rule that is intended to change past practices. There does not appear to be any analysis of the extent to which new HRI technology or Operating and Maintenance Practices (O&M) programs were used in this fleet-wide analysis, yet the ACE rule clearly requires such on-going O&M to demonstrate Heat Rate Improvement compliance. Including emissions rates and UDAFs for plants that do not implement the needed O&M is inappropriate. The assumption that Unit Degradation is inevitable has not been demonstrated, and is directly contradicted the Longview performance data over the last 10 years and by the new legal obligation to achieve and maintain a specified heat rate or adopt Heat Rate Improvements.

DAQ's Response to Comment #14

None of the O&M practices that are outlined in the emission guidelines prevent unit degradation. Longview Power's efforts to operate the most efficient unit possible, continually looking for and implementing HRIs at the facility, hide the unit's decay within OPM[28] data. The OPM data is on a net generation basis and is responsive to operating changes that affect the auxiliary load on the unit.

The 40 CFR Part 75 emission data can be used to determine a unit's heat rate; however, this data is limited because the heat rate can only be calculated on a gross basis. With the configuration of the Longview Power unit, this calculated heat rate would not take into consideration degradation of certain pieces of equipment that use electric energy to operate (e.g., electrically driven pumps, fans, mills, etc.).

The DAQ calculated the unit's heat rate on a gross basis from 2012 through 2nd Quarter 2020 by load bin. The following is the daily heat rate for Load Bin 5 with a linear trendline added to the chart.

[28] Black & Vetch's Online Performance Model

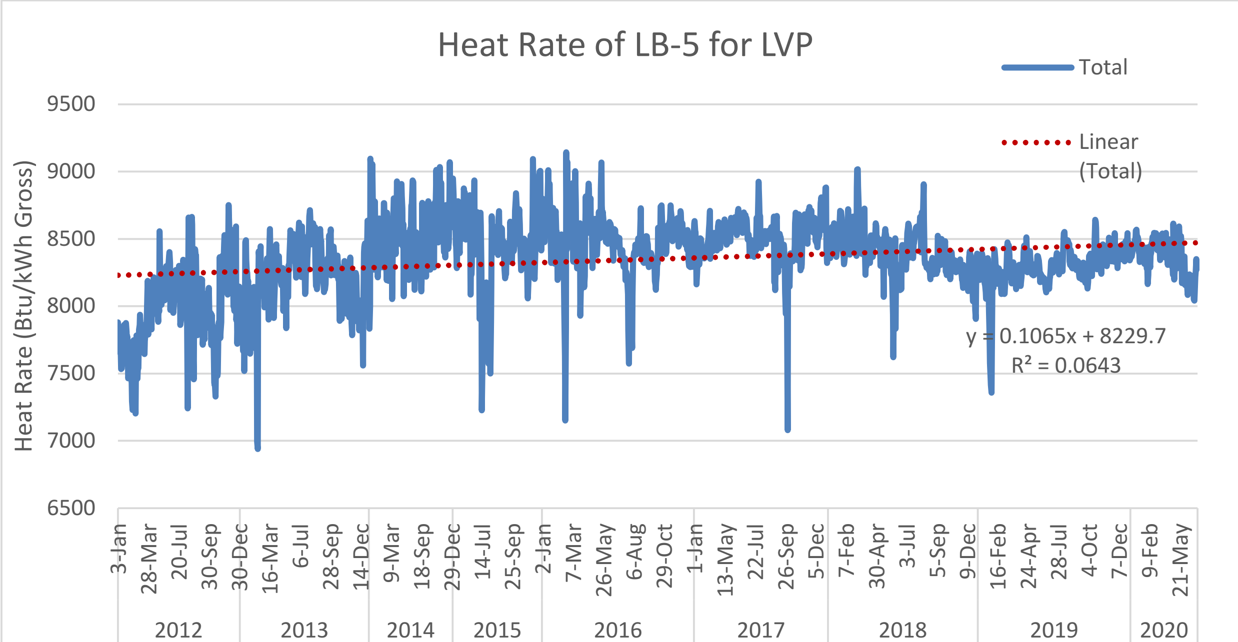


Figure 1: Chart of the Heat Rate of LB-5 for LVP

The trendline indicates that the unit is degrading at a rate of 0.11 Btu/kWh for each operating day, which equates to an increase of 40 Btu/kWh on an annual basis. The other load bins are decaying at a higher rate than Load Bin 5, which are presented in the following charts (see the increase of the slope of the predicted linear function for each bin).

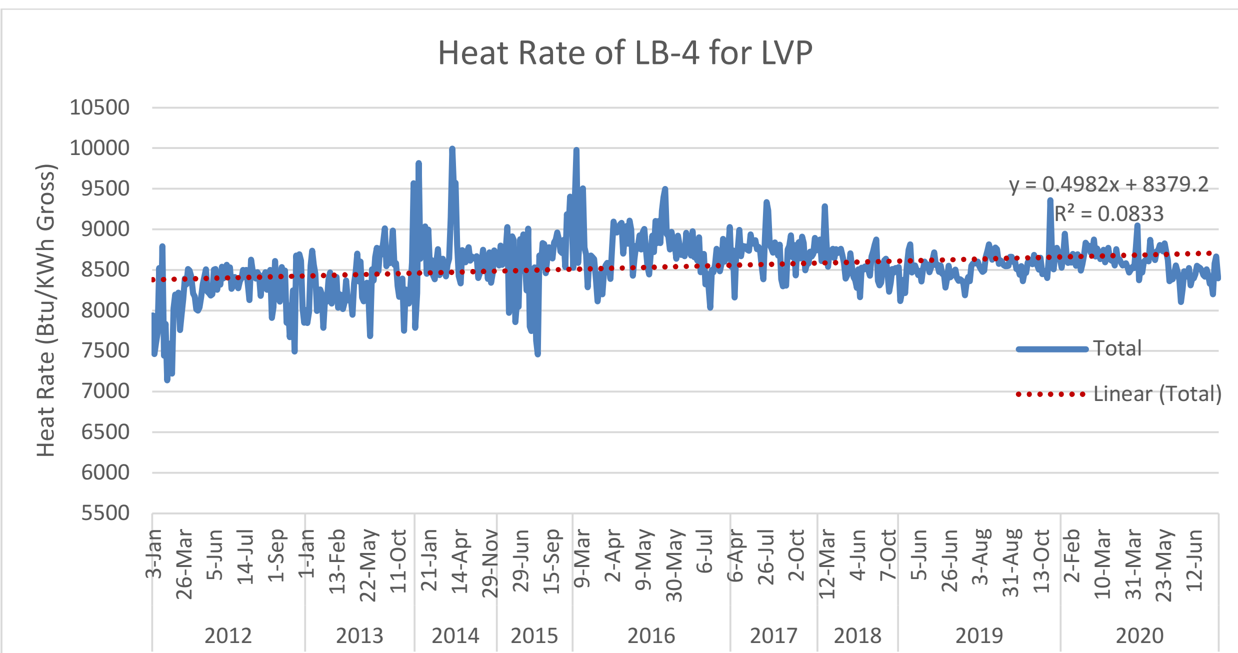


Figure 2: Chart of the Heat Rate of LB-4 for LVP

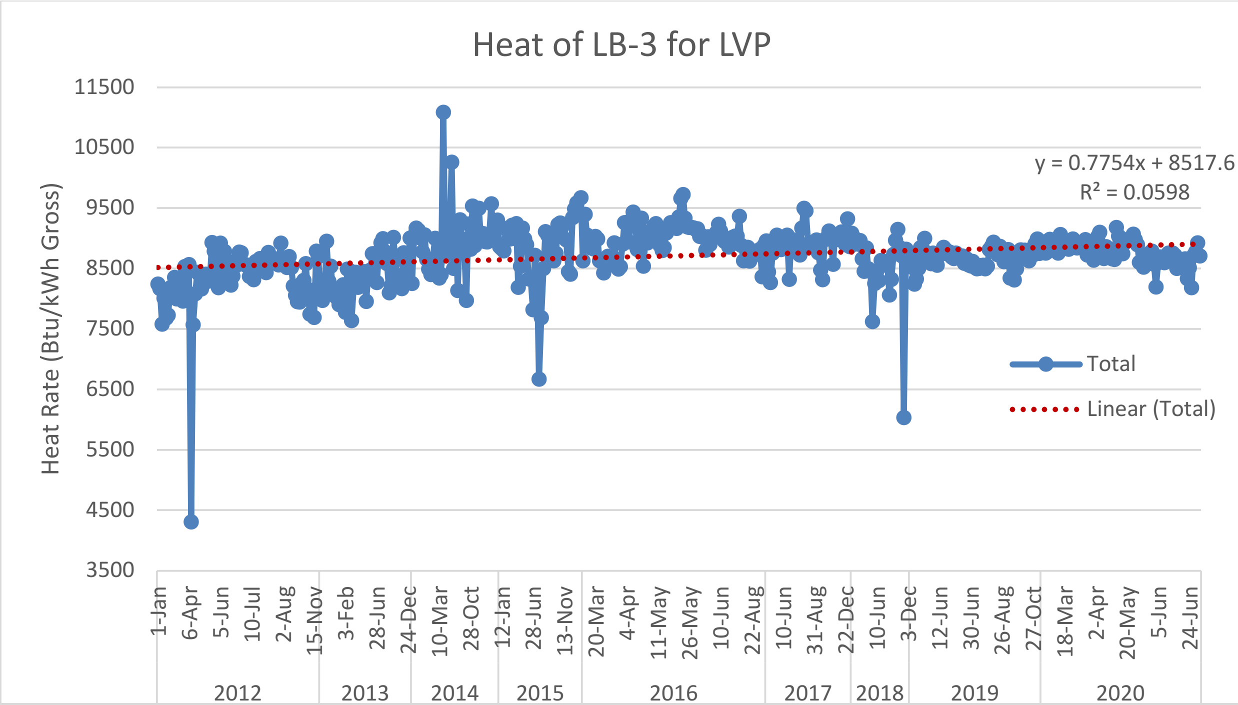


Figure 3; Chart of the Heat Rate of LB-3 for LVP

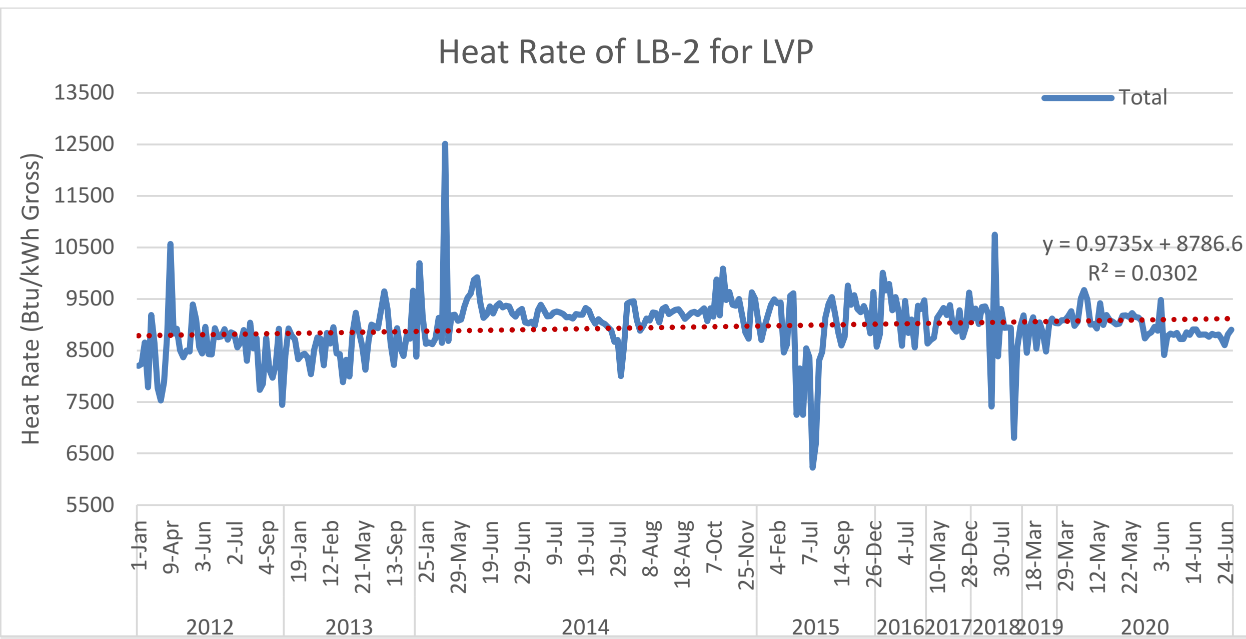


Figure 4: Chart of the Heat Rate of LB-2 for LVP

Final Determination for R13-3495
Longview Power LLC
Maidsville Facility
Non-confidential

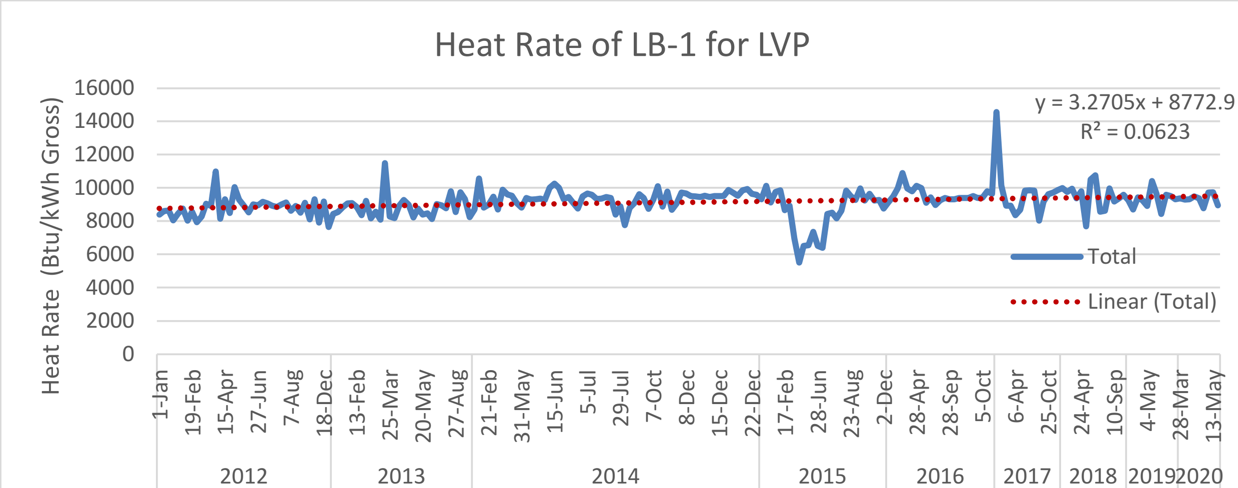


Figure 5: Chart of the Heat Rate of LB-1 for LVP

The proposed rate of 0.4% annually equates to approximately 35 Btu/kWh on an annual basis. These charts suggest that Longview Power will be required to find additional improvements to maintain compliance in the future or reduce the degradation rate by improving maintenance of equipment that affects the unit heat rate.

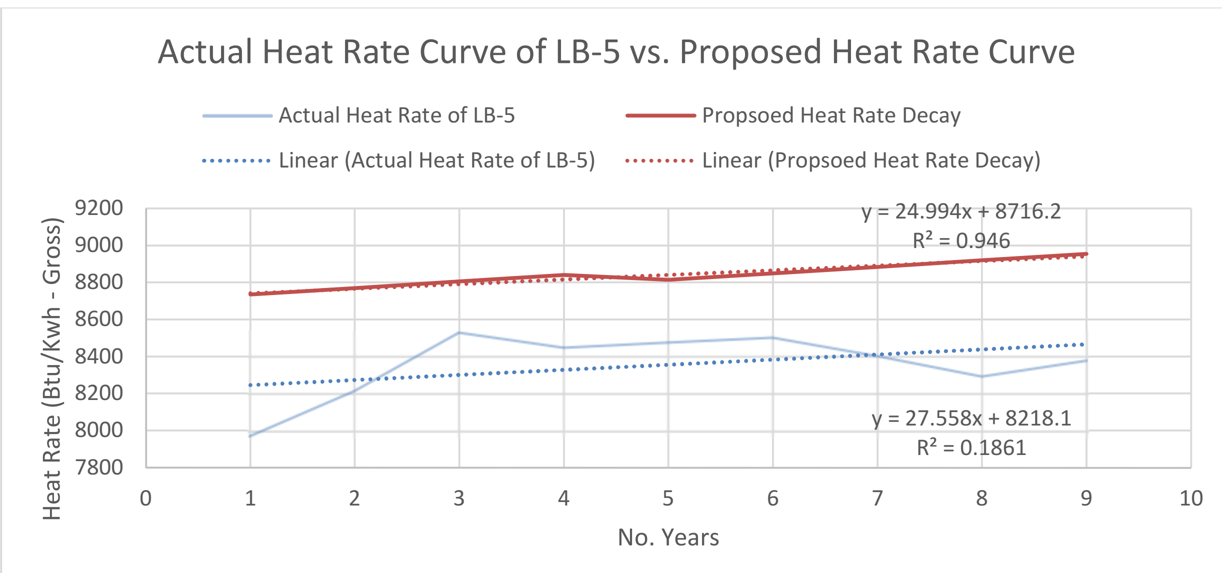


Figure 6: Actual Heat Rate Curve of LB-5 vs. Proposed Heat Rate Curve

The commenter did not provide any support of their claim that unit degradation is not inevitable.

Comment #15 from Commenter #6

The UDAF also allows the emissions rate increases to compound year-over-year, thus allowing much larger annual increases in later years. There does not appear to be any evidence to justify this, and Figure 20 shows a linear, not logarithmic, increase (even in plants not required to implement Heat Rate Improvements). Since the goal is to limit greenhouse gas emissions, we recommend that the permit use lower rates for UDAF, provide better justification for any non-zero UDAF, and apply them only to the base year, rather than using a compound interest approach as currently proposed.

DAQ's Response to Comment #15

The goal of the ACE Rule is to regulate greenhouse gas emissions by evaluating the HRI candidates that U.S. EPA has determined to be the BSER for existing units. The ACE Rule requires states to establish a performance standard based on the implementation of the feasible BSERs in accordance with the emission guidelines. The DAQ does not have the regulatory authority to require additional reductions outside of the scope of the emission guidelines.

The DAQ's Response to Comment #14 indicates that the rate of decay (slope) of the actual unit's heat rate is increasing faster that the proposed degradation rate set forth in the permit. (See Figure 6.) From Figure 6, the DAQ understands that Longview Power will have to improve the unit's actual recovery rate order to maintain compliance in the future (e.g., reduce the amount of heat rate that is lost due to equipment degradation) or implement additional HRI to offset the unit's degradation rate.

The DAQ reminds the commenter that the UDAF includes both a degradation rate and a recovery rate both of which are capped in 2046 and offers the additional justification below for the non-zero UDAF as requested by the commenter. 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.

LVP has been in commercial operation less than ten years; therefore, the steam turbine for the 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 to which the commenter refers.

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 cannot. Increased startup and shutdown (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 should 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.

Comment #16 from Commenter #6

WV-DEP has apparently uncritically accepted Longview's assertions regarding Heat Rate Improvement technologies. For example, it appears that the intelligent soot-blowing system performed better than EPA's estimated range would suggest. However, there is no evaluation as to whether the "intelligent combustion system" is a BSER-level of application of the technology. No data concerning the performance of the heaters and duct leakage was reviewed by DEP. Nor did DEP evaluate what technical improvements were available. DEP offers a number of general conclusions regarding O&M practices, but does not provide any specifics as to the nature and rigor of Longview's O&M practices, how they differ from those at other plants and why they are BSER. The list of practices that should be evaluated is lengthy, well beyond what Longview described in their application. We recommend that WV-DEP seek an independent analysis of HRI technologies.

<u>DAQ's Response to Comment #16</u>

The U.S. EPA identified a list of "candidate technologies" of the BSER that included technologies, equipment upgrades, and operating and maintenance practices that were deemed most impactful because they can be applied broadly and are expected to provide significant HRI without limitations due to geography, fuel type, and other characteristics. Those candidate technologies must be evaluated in establishing a standard of performance for each affected source within the state boundary. "(S)ome existing EGUs will have already implemented some of the listed HRI technologies, equipment upgrades, and operating and maintenances practices. There will also be unit-specific physical or cost considerations that will limit or prevent full implementation of the listed HRI technologies and equipment upgrades."[29] The list of candidate technologies include: neural network/intelligent sootblower, boiler feed pumps, air heater and duct leakage control, variable frequency drives, blade path upgrade (steam turbine), redesign/replace economizer, and improved operating and maintenance practices. [30] The "intelligent combustion system" was not identified by U.S. EPA as a BSER candidate technology. Please refer to pages 6 through 19 of the Engineering Evaluation for Permit R13-3495 for an in-depth discussion of the analysis conducted by DAQ concerning these candidate technologies that is more comprehensive than the information provided in the permit application to which the commenter referred.

The emission guideline does not require that the applicant's heat rate improvements be compared to other units or heat rate studies be conducted by independent firms.

U.S. EPA determined that it would be best to allow the states to establish performance standards on an individual unit basis due to the differences in operating characteristics, designs, fuel types, and other factors. There are numerous factors that will affect a unit's heat rate. In order to compare different units on a unit-by-unit basis, the actual design, operating mode, fuel, and maintenance plans would, at a minimum, need to be determined for both units.[31]

The emission guidelines do not require the affected units to measure their improvements. Not all HRIs are measurable because they are small and are often within the variation of the measurement instrument's margin of error. Therefore, the degree that a specific improvement makes on a unit's heat rate is difficult to measure or quantify. One piece of the system could be degrading and hide an improvement in another part of the system. The unit's heat rate may not improve because other downstream process equipment may not be capable of taking advantage of the improved efficiency of the upstream process. Additionally, some HRIs will only improve the heat rate on a net generation basis and cannot be observed on a gross generation basis.

The baseline period used for Longview Power is representative of the HRIs already implemented which EPA determined to be BSER candidate technologies. The emission guidelines require that for those BSER candidate technologies that have not been implemented but are feasible to implement, the potential improvement of such candidate technology should be identified and applied to the actual standard. However, during the evaluation for Longview Power, no other HRIs were found that meet this criteria and, therefore, no adjustments were made.

It should be noted that the emission guidelines do not specify that a source must implement a particular HRI to achieve compliance[32]. The operator has a choice of which measures or technologies to implement in order to achieve compliance with the standard by the compliance

[29] 84 Fed. Reg. 32537. (July 8, 2019)
[30] 84 Fed. Reg. 32536-32537. (July 8, 2019)
[31] 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, June 2019, page ES-14
[32] 84 Fed. Reg. 32555. (July 8, 2019)

date. The implemented HRI technologies may be different than the technologies that were identified as BSER candidate technologies.

Longview Power did have an independent firm evaluate the feasibility of the feed water pump, and variable frequency drives HRI candidates with respect to their unit.[33] See DAQ's Response to Comment #8 for additional remarks.

Comment #17 from Commenter #6

WV-DEP has apparently accepted Longview's contention that they will continue to operate as a base load plant (page 48 of the EE), however, this ignores the abundant evidence of market realities in our region. Use of coal as a fuel for generating electricity is declining, and the Capacity Factor of plants is declining as well, as demonstrated in Figure 19 of the EE. Most projections show that this rate of decline will accelerate in coming years. That means it is realistic to expect an increased frequency of operations in Load Bins 1-4, and especially, an increase in Load Bin 0, as the plant shuts down more often. The goal of regulating greenhouse gas emissions is to prevent just such increases. We recommend that total emissions per year be capped, to prevent Longview from "gaming" the system and dramatically increasing greenhouse gas emissions by operating in inefficient Load Bins or engaging in excessive shut downs and start-ups. Furthermore, WV-DEP should require Longview to evaluate feasibility of additional Heat Rate Improvement technologies in these reduced unit Load Bins.

DAQ's Response to Comment #17

Understanding the historic operating mode is important in processing the data. Market conditions and the unit's operating cost will determine how the unit will operate in the future. By establishing the limits on a bin basis and setting the standard on a weighted-average basis, the operating mode of the unit does not affect the unit's ability to comply with the standard. These bin limits are based on operating data within the selected base line period and, therefore, are representative of the unit's operating efficiency within the respective operating loads.

Capping mass emissions is not an option for states to use in establishing emission limits in accordance with the emission guidelines. The regulation is very clear that the standard must be performance-rate based relating the mass of carbon dioxide emitted per unit of energy.[34] The regulation prohibits a mass-based form for the performance standard.

As explained in DAQ's Response to Comment #1, the limits in Permit R13-3495 do not relieve Longview Power of the responsibility to comply with all of the requirements established in R14-0024G which includes a limit on the amount of heat energy that can be burned in their electric generating unit (EGU). This heat energy input limit indirectly caps Longview's carbon dioxide emissions on a mass basis. However, this indirect cap is not in the form of the CO_2

[33] Black & Vetch, Longview Unit 1 Heat Rate Study, July 31, 2020.
[34] 40 CFR §60.5755a(a)(1)

standard as set forth in the emissions guidelines[35] and, therefore, is not acceptable as a limit in Permit R13-3495. Permit R13-3495 does not replace or increase this heat input restriction in Permit R14-0024G.[36]

Oral Comments Made during the October 27 Public Meeting

Angie Rosser, West Virginia Rivers Coalition – 16:40

Trying to understand how BSER candidate technologies are determined. If they are determined by some type of national survey average of what the status quo is. That is not good enough. Wrong direction. Bottom line is to improve this permit, so it reduces and not increases emissions.

DAQ's Response to Ms. Rosser's Comments

U.S. EPA established the BSER candidate technologies. "It is the EPA's responsibility to determine the BSER for designated facilities for standards developed under both CAA section 111(b) for new sources and section 111(d) for existing sources. In making this determination, the EPA identifies all "adequately demonstrated" "system[s] of emission reduction" for a particular source category and then evaluates those systems to determine which is the "best" while "taking into account" the factors of "cost . . .non-air quality health and environmental impact and energy requirements."[37]

U.S. EPA's full justification and rationale for establishing these BSER candidate technologies are in the preamble to the ACE Rule and Regulatory Impact Analysis for the ACE Rule. A brief overview from the background and BSER determination by the U.S. EPA is quoted below:

> Heat rate is a measure of efficiency that is commonly used in the power sector. . . The lower an EGU's heat rate, the more efficiently it converts heat input to electrical output. As a result, an EGU with a lower heat rate consumes less fuel per kWh of electricity generated and, as a result, emits lower amounts of CO_2—and other air pollutants—per kWh generated (as compared to a less efficient unit with a higher heat rate). Heat rate data from existing coal-fired EGUs indicate that there is potential for improvement across the source category.
>
> Heat rate improvement measures can be applied—and some measures have already been applied—to all existing EGUs (supporting the Agency's determination that HRI measures are the BSER). . . T(t)he the EPA identified several available technologies and equipment upgrades, as well

[35] 40 CFR §60.5755a(a)(1).
[36] Permit R14-0024G, Condition 5.1.1.a.
[37] 84 Fed. Reg. 32534 (July 8, 2019)

as best operating and maintenance practices, that EGU owners or operators may apply to improve an individual EGU's heat rate. The EPA referred to these HRI technologies and techniques as "candidate technologies".[38]

Longview has clearly demonstrated that all the feasible HRIs that were identified as BSER candidate technologies by U.S. EPA have been installed or implemented by Longview Power. Thus, the proposed carbon dioxide standard for the ACE Rule cannot reduce Longview Power's carbon dioxide rate any further than what it is achieving today. This does not mean that Longview Power will not implement additional improvements in the future.

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.[39]" 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[40]. The heat rate for Longview Power from the NEEDS_v6 database is 8,904 Btu/kWh and therefore is one of the Group 1 most efficient coal fired EGUs in the country, as shown in the table below.

Plant Name	State Name	Capacity (MW)	Heat Rate (Btu/kWh)	On Line Year
Longview Power Plant	West Virginia	700	8904	2011
James E. Rogers Energy Complex	North Carolina	844	9090	2012
John W Turk Jr Power Plant	Arkansas	609	9102	2012
Belews Creek	North Carolina	1110	9185	1974
Belews Creek	North Carolina	1110	9203	1975
Marshall (NC)	North Carolina	660	9300	1965

Figure 7: List of the Most Efficient Coal Fired Units in the US in 2020.[41]

The ACE rule requires the analysis of each BSER candidate technology for applicability to an affected EGU, in this case, Longview. If it has been demonstrated that the BSER candidate technology has already been implemented and no further regulatory reductions are possible, this HRI analysis meets the intent of the ACE Rule.

[38] 84 Fed. Reg. 32535 (July 8, 2019).
[39] 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
[40] *Ibid.*, Page 1-13
[41] https://www.epa.gov/sites/production/files/2020-10/needs_v620_10-05-20_0.xlsx

As noted in the engineering evaluation, Longview Power is a merchant power plant. The amount of electricity that it generates is entirely dictated by the demand for electricity in the PJM marketplace. No West Virginia ratepayers or other state ratepayers compensate Longview Power to make any investment to its unit. Longview Power is motivated to be the most efficient operator in the PJM market, which means it generates electricity in the most fuel-efficient manner it can.

Market conditions are what drove Longview Power to install the HRIs that have already been installed, in absence of any federal or state regulatory requirements. The installation of the improvements by Longview Power is the reason they are one of the most efficiently run coal-fired EGUs in the nation (See Figure 7).

The PJM RTO dispatches units like Longview Power based on who is available to generate electricity and in order of the lowest cost generation first. For Longview Power to continue to be dispatched at or near its full capacity, Longview Power's management team continues to look for improvements or measures to maintain the unit heat rate at the lowest level possible (most fuel-efficient manner).

Please also refer to the DAQ' Response to Comment #1 above.

Stephen Nelson, Longview Power – 20:30

Thanks everyone for attending and weighing in.

DAQ's Response to Mr. Nelson's Comments

No response required.

Leah Barbor, Moms Clean Air Force – WV – 21:38

Opposes this rule and mirrors some of West Virginia Rivers concerns. Greenhouse gas emissions have adverse effects on our health and welfare. EPA has a legal obligation to limit the pollution that endangers our health and welfare but the ACE Plan doesn't fulfill this legal obligation. Recognizes that energy efficiency measures have value, but they should also include emissions reductions. It is unacceptable that the draft permit would allow substantial increases in greenhouse gas emissions for years to come, growing at a rate of 0.4 percent every year. Baseline emission rate being 60 pounds of CO_2 per megawatt hour beyond the actual 2019 rate seems irresponsible and unnecessary.

DAQ Response to Ms. Barbor's Comments

The Unit Degradation Adjustment Factor (UDAF) only allows an increase in the bin limit of 0.4% annually with a recovery factor (decrease in the bin limit) of 0.7% once every five years. The demand for electricity was high in 2019 which allowed Longview Power to operate their unit at on steady state basis for most of the year.

Simply looking at the annual rates from Table 1[42] and comparing these values to the bin limits does not paint an adequate picture as to whether the limit is too high or is never going to require any further improvement on the applicant's part to maintain compliance. Assuming the annual rates from the table are representative of Load Bin 5 and taking the average of the four whole years of the baseline period (2016-2019), the margin of compliance would only be 1.5% over this four-year period.

Due to the variability in the source's emission data and current trend in the power generation sector, the probability of Longview Power to continually reduce its CO_2 rate or heat rate is highly unlikely without significant advancements outside of the scope of the BSER candidate technologies in the emission guidelines.

The DAQ had to develop a constraining and achievable limit. Because the evaluation of the BSER candidate technologies with respect to Longview Power's unit did not find any additional potential improvements within U.S. EPA's suggested range, the bin limits and standard must be established with a demonstration that the standard is achievable today.

Please refer to the DAQ's Response to Comment #14 above and the DAQ Response to Mr. Kotcon's Comment #6 below for additional discussion concerning the UDAF.

Michael Nasi, Jackson Walker LLP – 25:05

Echoes Steve Nelson's comments. Will be the first national carbon dioxide limit.

<u>DAQ's Response to Mr. Nasi's Comments</u>

No response required.

Michelle Bloodworth, America's Power – 30:13

Speaking in support of the permit for Longview Power.

<u>DAQ's Response to Mr. Bloodworth's Comments</u>

No response required.

Chris Hamilton, West Virginia Coal Association – 35:28

Appreciates opportunity to participate in support of permit for Longview Power.

<u>DAQ's Response to Mr. Hamilton's Comments</u>

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[42] WVDEP-DAQ, Engineering Evaluation of R13-3495, October 8, 2020, page 6.

No response required.

Patrick Morrisey, West Virginia Attorney General – 40:43

This application should be advanced. Thanks everyone for taking the time to be involved in this process. Urges to move forward.

DAQ's Response to Mr. Morrisey's Comments

No response required.

Carol Miller, Congresswoman – 46:07

Speaking in support of Longview's application.

DAQ's Response to Ms. Miller's Comments

No response required.

James Kotcon, West Virginia Chapter of the Sierra Club – 50:10

1. *Will submit written comments before November 9. Does DEP recognize that there is absolutely no need to regulate greenhouse gas emissions except to limit climate change? This permit recognizes that that is the issue we are trying to resolve here.*

DAQ's Response to Mr. Kotcon's Comment #1

U.S. EPA has mandated that states are required to develop carbon dioxide emission standards in accordance with the emission guidelines outlined in the ACE Rule. See DAQ Response to Comment #3 of the written comments. U.S. EPA listed numerous benefits of reducing carbon dioxide emissions which are outlined in the regulatory impact analysis[43], which includes climate benefits and human health co-benefits from the successful implementation of the ACE Rule across the United States.

2. *Given that the West Virginia Legislature has not yet approved the rules to implement the Affordable Clean Energy Act, does DEP actually have any legal authority to issue and enforce this permit?*

DAQ's Response to Mr. Kotcon's Comment #2

45CSR13 requires that DAQ review and issue a permit for all permit applications that indicate that the source will not exceed an applicable standard or exceed an ambient air

[43] 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, June 2019, Chapter 4

quality standard.[44] This applies to all permit applications including applications to establish a limit on a voluntarily basis. Please referrer to DAQ's Response to Comment #3 for additional information.

3. *Is this the first permit under the Affordable Clean Energy Act in the U.S.? If not, what precedence does DEP rely on for this permit? If it is, is it DEP's intent to use the Longview permit for other coal-fired power plants in West Virginia?*

DAQ's Response to Mr. Kotcon's Comment #3

The Longview permit will be the first permit under the ACE Rule in the U.S. that DEP is aware of. Any future applications will be evaluated on a case-by-case basis.

Any additional response from the DAQ on the intent that this approach used to develop a CO_2 standard would be applied to other units would not be appropriate since the West Virginia Legislature has not yet approved a rule for West Virginia to develop a plan to comply with the ACE Rule.

Neither the WVDEP nor the DAQ has made Longview Power any guarantees that the proposed standard in the permit will conform or be grandfathered into any rule that the West Virginia Legislature may approve for West Virginia to comply with the ACE Rule. Longview Power has taken the risk to submit this voluntary permit application at this time and the DAQ is obligated to process the application in accordance with 45CSR13.[45]

4. *In their application Longview used data from a number of years prior to implementing some of the heat rate improvement installations in 2018, so is it appropriate to include uncontrolled emissions to calculate limits for the controlled emissions after this permit takes affect? That troubles me.*

DAQ's Response to Mr. Kotcon's Comment #4

The selected baseline period is 2016 to 2nd Quarter of 2020. Longview Power had either installed or implemented the heat rate improvements that were within the scope of the BSER candidate technologies in the emission guidelines prior to 2016.

It is worth reiterating that the BSER for CO_2 emissions under the ACE emission guidelines is HRI from identified candidate technologies to more efficiently convert heat input to electrical output to consume less fuel per kWh of electricity generated and, as a result, emits lower amounts of CO_2 per kWh generated[46]. The comment indicates "uncontrolled" and "controlled" emissions; however, the identified BSER is not a traditional add-on control device to reduce emissions.

[44] 45 CSR §13-5.7.
[45] 45 CSR §13-5.7.
[46] 84 FR 32534 (July 8, 2019)

Longview has made additional improvements that were implemented during the selected baseline period. Some of these improvements take advantage of the BSER candidate technologies or increased the potential HRI of BSER candidate technologies. It should be clear that Longview Power has made these additional improvements prior to U.S. EPA proposing or promulgating the ACE Rule.

The emission data from the baseline period includes the benefit of these additional improvements which was used in the development of the individual load bin limits. Excluding emission data because the dataset did not contain all the improvements made at a unit regardless of the BSER candidate technologies is not reasonable.

5. *Has DEP or Longview considered cofiring biomass as part of its permit? Is there any mechanism in the permit to allow or encourage the use of biomass fuels in addition to cofiring with coal?*

DAQ's Response to Mr. Kotcon's Comment #5:

The use of biomass fuels is not identified as BSER HRIs in the emission guidelines. U.S. EPA concluded that biomass co-firing did not meet compliance measure criteria because "biomass firing in and of itself does not reduce emissions of CO_2 emitted from that source. Specifically, when measuring stack emissions, biomass emits more CO_2 per Btu than fossil fuels, thereby increasing the CO_2 emission rate at the source."[47] There are other pollutant impacts and regulatory issues to co-firing with biomass that are outside of the scope of the Longview Power application and which would be required to be addressed under the DAQ's major source permitting rule.[48] In the ACE Rule, U.S. EPA did not make a final decision concerning the role of New Source Review reforms for sources implementing any of the BSER candidate technologies identified in the emission guidelines.[49]

The permit does not specifically prohibit Longview Power from firing other fuels to comply with the proposed standard. However, Longview Power would have to address the applicability of 45CSR14[50] for any physical changes or changes in method of operation to accommodate these other fuels and any limitation under their Permit R14-024G that may conflict or restrict these other fuels.

[47] 84 FR 32547, 32557-32558. (July 8, 2019)
[48] 45 CSR 14, PERMITS FOR CONSTRUCTION AND MAJOR MODIFICATION OF MAJOR STATIONARY SOURCES FOR THEPREVENTION OF SIGNIFICANT DETERIORATION OF AIR QUALITY
[49] 84 FR 32521. (July 8, 2019)
[50] 45 CSR 14

6. *Longview assumes that the efficiency of their facility declines with age and that might seem intuitively obvious, but does DEP have any data from a modern coal-fired power plant such as Longview, one that is well maintained, to show that this is inevitable? Is there any reason to think that with proper maintenance the emissions level has to continuously increase?*

<u>DAQ's Response to Mr. Kotcon's Comment #6:</u>

The DAQ was reluctant to consider other plant data (heat rate) as a benchmark in developing the standard or in specifically justifying Longview Power's degradation rate. In comparison of best heat rate with Longview Power's unit, AEP's John W. Turk Plant in Arkansas is one of the best performing units. Both units are comparable in age with less than a one-year difference. The Turk unit was designed to operate as an ultra-super critical unit, which is more efficient than a super critical unit.

The Arkansas' Office of Air Quality provided the DAQ with the following chart of the heat rate of the Turk Plant. The chart indicates that the Turk Plant is degrading at a rate of 48 Btu/kWh on a gross generation basis per year. This rate is significantly higher than what Longview Power proposed, which equates to 35 Btu/kWh on a gross generation basis per year.

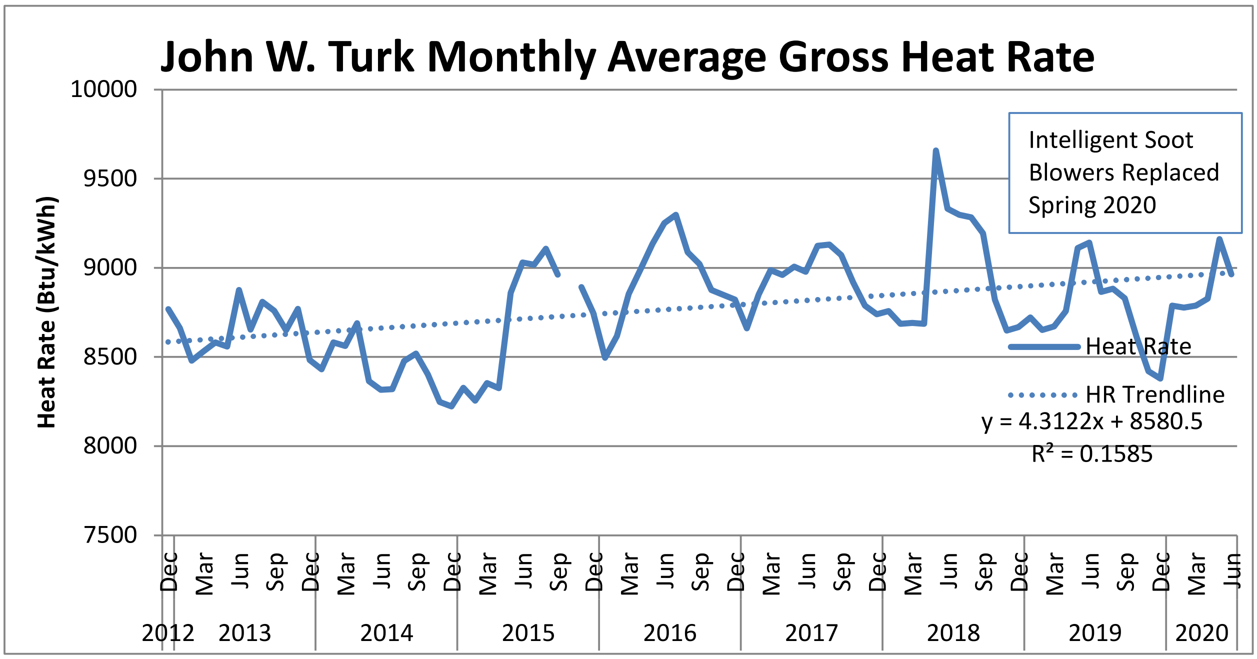

Figure 8: Chart of Heat Rate of the John Turk Plant[51]

Before making any conclusions, the DAQ contacted AEP, the owner and operator of the Turk Plant, to identify key differences in the design of the Turk Plant with respect to the Longview Power Unit. The DAQ obtained and processed the Clean Air Markets Division

[51] Arkansas Department of Energy and Environment, Division of Environmental Quality, September 29, 2020.

(CAMD) data on the Turk Plant into load bins representing baseload operation in similar fashion to DAQ's approach in developing the bin limits for Longview Power.

The DAQ developed the following chart of the Turk Plant at its upper (baseload) operating bin, which is the upper one fifth of the unit's operating range.[52]

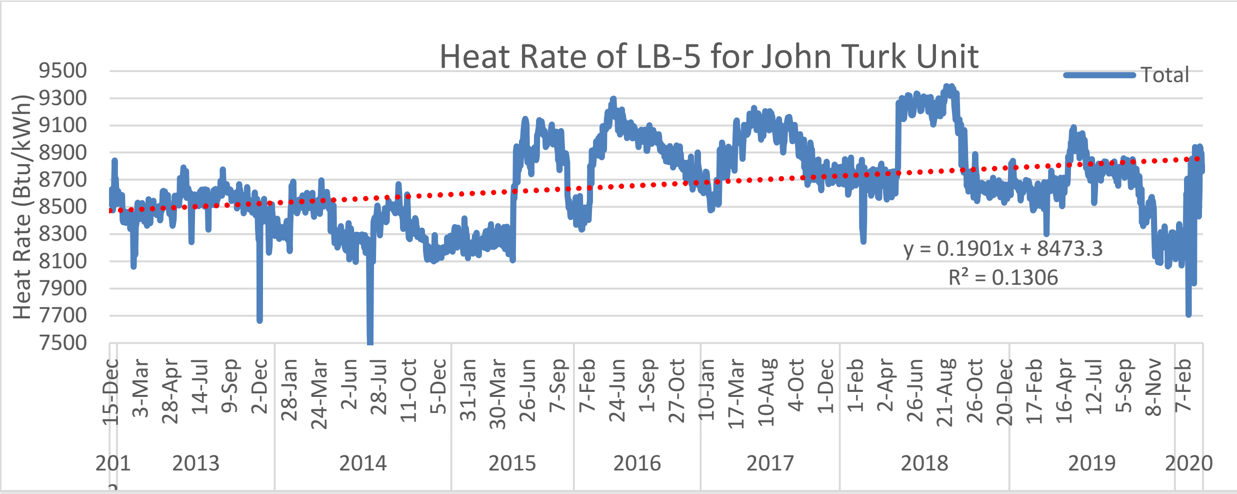

Figure 9: Chart of the Heat Rate of LB-5 for the John Turk Unit

The DAQ enhanced the resolution of the chart by calculating the heat rate of LB-5 using the reported hourly operating data and averaging the heat rate daily. The added trendline estimated the degradation rate for this bin to be 69 Btu/kWh on an annualized basis.

It should be noted that the Turk Plant operates at different steam pressures and temperatures than Longview Power. The Turk Plant consumes sub-bituminous coal as its primary fuel which has a lower heating value than the bituminous coal burned at Longview Power.[53] The Turk Plant uses a dry lime flue gas desulfurization system to control sulfur dioxide (SO_2) and uses steam-driven feed water pumps. These designs and operating characteristics make it difficult to compare these the two units.

The DAQ downloaded the CAMD data for 12 other units and processed these data sets in a similar manner. The DAQ selected these units by sorting the U.S. EPA National Electric Energy Data System (NEEDS) database of EGUs by plant type: steam coal; online year: 2003 and newer; capacity (MW): 500 or greater than; and, a heat rate (Btu/kWh): 9,773 or less.

[52] John W. Turk Plant, ORRIS No. 56564, Reported Emissions data to U.S. EPA CAMD.
[53] Energy Information Administration, Form 923 for 2019, [Form EIA-923 detailed data with previous form data (EIA-906/920)]

Table 3: List of the Newest, Best Preforming Coal-Fired EGUs in the U.S.							
Plant Name	**ORIS Plant Code**	**Unit ID**	**State Name**	**Capacity (MW)**	**Heat Rate (Btu/kWh)**	**On Line Year**	**Fuels**
Cross	130	3	South Carolina	600	9772	2007	Bituminous
James E. Rogers Energy Complex	2721	6	North Carolina	844	9090	2012	Bituminous, Natural Gas
Weston	4078	4	Wisconsin	550	9679	2008	Subbituminous
Prairie State Generating Station	55856	PC1	Illinois	815	9391	2012	Bituminous
Prairie State Generating Station	55856	PC2	Illinois	815	9346	2012	Bituminous
Elm Road Generating Station	56068	18	Wisconsin	633	9552	2010	Bituminous, Subbituminous
Elm Road Generating Station	56068	19	Wisconsin	633	9475	2011	Bituminous, Subbituminous
Plum Point Energy Station	56456	BLR1	Arkansas	680	9682	2010	Subbituminous
John W Turk Jr Power Plant	56564	1	Arkansas	609	9102	2012	Subbituminous
Sandy Creek Energy Station	56611	S01	Texas	933	9330	2013	Subbituminous
Longview Power Plant	56671	UHA01	West Virginia	700	8904	2011	Bituminous
Iatan	6065	2	Missouri	882	9502	2010	Subbituminous
Trimble County	6071	2	Kentucky	732	9716	2011	Bituminous, Subbituminous

About half of these units had a calculated heat rate curve that indicates the units are experiencing degradation. The other half indicates that their heat rate curve is improving (decreasing). Focusing on units burning only bituminous coal, the comparable units were reduced to four units at three different facilities.

Table 4 List of the Newest Best Preforming EGUs in the US using Bituminous Coal						
Plant Name	**ORIS Plant Code**	**Unit ID**	**State Name**	**Capacity (MW)**	**Heat Rate (Btu/kWh)**	**Online Year**
Cross	130	3	South Carolina	600	9772	2007
Prairie State Generating Station	55856	PC1	Illinois	815	9391	2012
Prairie State Generating Station	55856	PC2	Illinois	815	9346	2012
Longview Power Plant	56671	UHA01	West Virginia	700	8904	2011

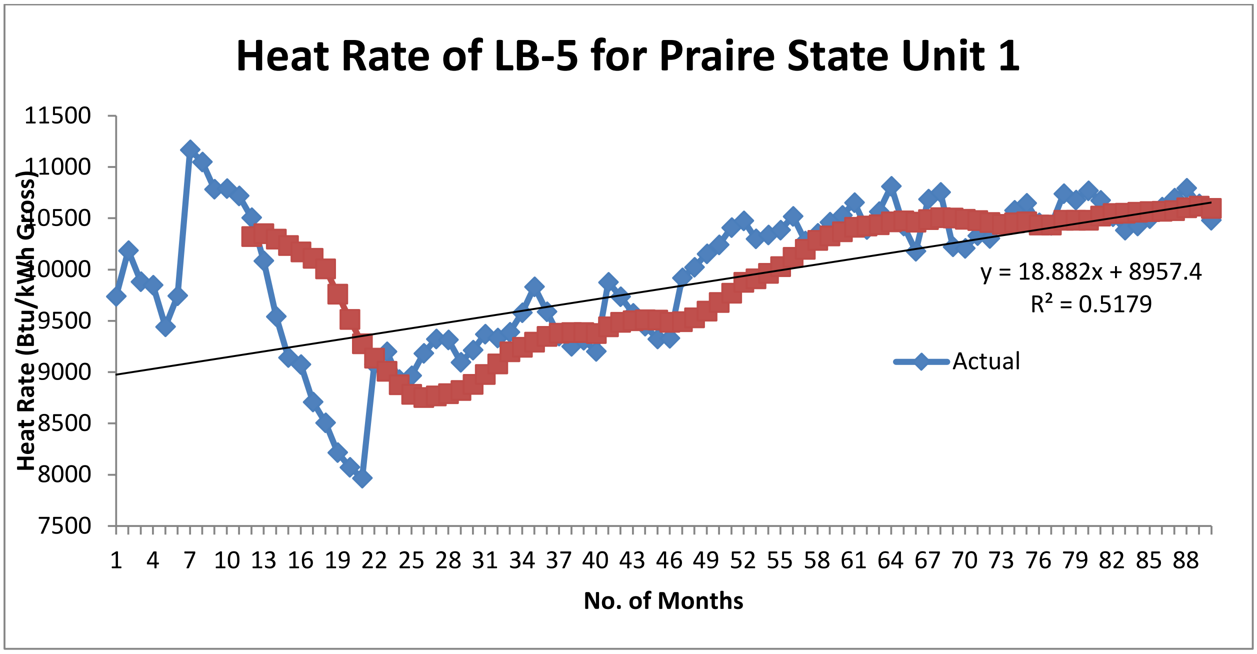

Figure 10: Heat Rate of LB-5 for Prairie State Unit 1

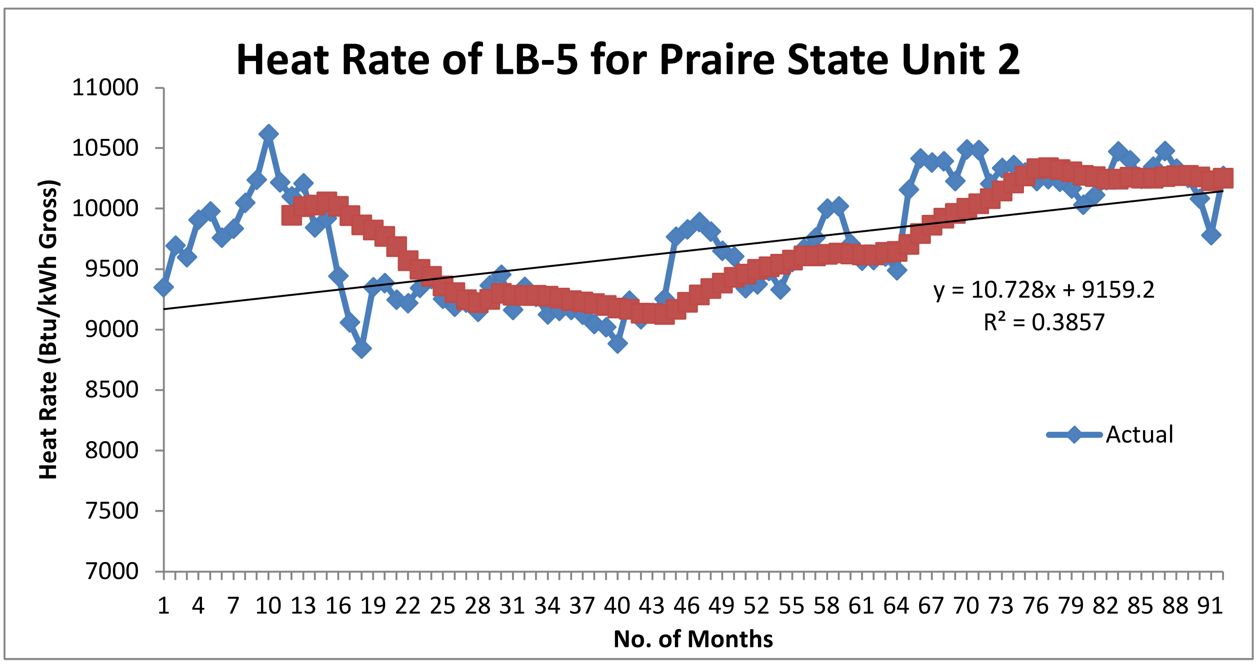

Figure 11: : Heat Rate of LB-5 for Prairie State Unit 2

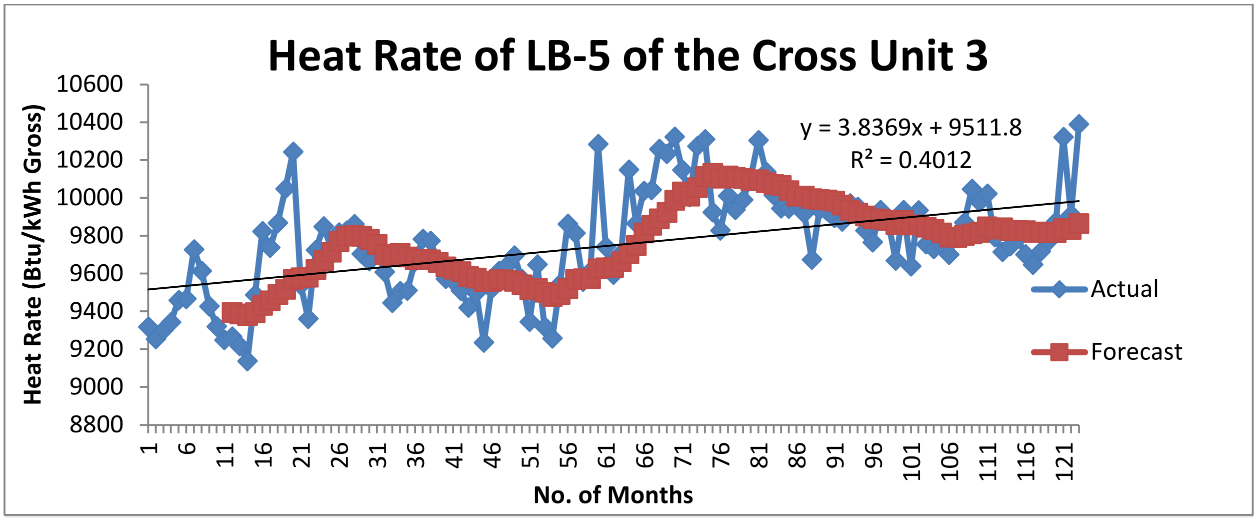

Figure 12: Heat Rate of LB-5 for Cross Unit 3

The forecast curve in each of these was performed used a moving (rolling) average of the actual heat on an interval of 12 months.

The charts for all these units clearly indicate a degradation rate higher than what Longview Power proposed. The DAQ believes these charts (Figures 9 through 12) answer the commenter's questions. It should be noted that the DAQ could not explain or understand the heat rate curves for all of these best performing newer units and, therefore, did not rely on these charts to justify the use of the proposed degradation rate in the UDAF in the permit. The DAQ has no means to determine or verify that maintenance practices for these other units are being implemented in a sound and timely manner in an effort to minimize the effects of unit degradation, because they are outside of the units regulated by the State of West Virginia. The DAQ, therefore, does not have the in-depth knowledge of these units, as it does with the EGUs within its jurisdiction. There could be other changes or factors at these facilities that could be affecting the unit heat rate or CO_2 emission rate which are unknown to the DAQ.

7. *Has DEP when they established their six different bins recognized that a lower capacity or lower bin level seems to be increasingly likely? The U.S. Energy Information Agency concluded just this week that solar energy is the cheapest electric generation in the United States. The competitiveness of Longview seems likely to go down and what basis do we have for using these lower generating capacity load bins for estimating greenhouse gas emissions? In particular load bin 0, which is established in section 4.1.1.a.i. of the permit, has a limit of 9,864 pounds per megawatt hour. That is more than five times the emissions rate for the highest load bin 6. That bin applies whenever the plant is operating at less than 313 megawatts. So, if the plant is only operating at 40 percent of its capacity, they are allowed to let their emissions go through the roof at five times the rate. I have quite a number of other questions and I hope to ask them after.*

DAQ's Response to Mr. Kotcon's Comment #7

The DAQ recognized that the heat rate is different at these different loads which results in different CO_2 rates from the unit. These lower load bin limits were developed using actual unit emissions data while the unit operated in these ranges, the DAQ considers the emission rates of these load bins as unit-specific operating characteristics. U.S. EPA clearly stated that the standard should reflect the unit-specific operating factors and characteristics.[54]

DAQ believes that market conditions will ultimately decide at which load(s) Longview Power will be operating. The weighted average approach for establishing a standard allows units like Longview Power the most flexibility to operate regardless of load or operating conditions. The limit or standard is based on actual performance in all operating ranges. The DAQ believes establishing a single standard over the entire operating range would have the potential for compliance issues and/or require re-development of the standard when operating modes change. It should be noted that not all of the BSER candidate technologies that U.S. EPA identified in the emission guidelines will provide HRI at all operating loads.

As market conditions change, Longview Power will have to make decisions on whether to operate and how much to invest in the unit to maintain a competitive operating performance level. The CO_2 weighted average standard established in the permit is what Longview Power will have to achieve when operating regardless of which load the unit is operating at. The specific bin limits for these lower bins were developed in the same manner as the limits for the upper load bins using all the emissions data available during the baseline period. The weighted average standard is weighted based on hours of operation in each of the respective operating load bins over the compliance period. The standard automatically adjusts based on the actual load operations of the unit.

The DAQ was focused on establishing a constraining standard while allowing for a reasonable amount of degradation in the future. Setting a single standard would either not be constraining today or would not be achievable in the future. Likewise, setting a single standard to cover all the operating loads would have the same issues.

The startup process for these types of units is not as simple as just pushing a button or turning a knob. The unit must be preheated, which involves burning some sort of fuel for an extended period before any energy output (electrical generation) occurs from the unit. CO_2 emissions are being emitted during this phase even when no electrical generation is occurring. The emission guidelines have no provisions to allow for work practice measures in lieu of a numerical emission standard. Load Bin 0 (LB-0) accounts for the time the unit is being heated on startup fuel when no generation is occurring and until the unit reaches a stable operating load. During this load range (0 – 313 MWh), operators are performing

[54] 84 FR 32552. (July 8, 2019)

several startup tasks to get the unit past startup and up to a minimum operating load waiting for PJM to dispatch the unit. During this phase, any electric generation from the unit is being consumed by the unit or lost, which means Longview Power is not generating revenue while operating in this load bin. The bin limit for LB-0 is significantly higher than the other bins because the amount of energy generated is significantly less in this operating range (0 – 313 MWh).

The CO_2 emission rate during startup events could easily drive or dictate a higher standard without the bin approach. To avoid this and to ensure all the CO_2 emissions are being counted, the DAQ elected to establish a separate load bin standard to account for periods or events (startups and shutdowns) that occur below the normal operating range of the unit.

During this phase of very low generation, mathematically the CO_2 rate is high. As noted in Figure 13 of the evaluation[55], the mass emissions of CO_2 emitted while operating in LB-0 is a small fraction of the total CO_2 emitted from this source. The emission guidelines do not allow work practice limitations during startup or shutdown conditions and require a numerical limit at all times.[56] The following table was developed to better demonstrate the issues associated with establishing an emission standard to cover periods of startup and shutdown events.

Row Labels	Hours of operation with No Generation	Total Hours of Op. in LB-0	% of Time of No Generation while OP in LB-0	CO2 with no Generation	% of Mass Rate of CO2 in LB-0 with No Generation
2012	80	336.5	23.8%	9,517.10	26.0%
2013	99	158.9	62.3%	8,959.70	47.0%
2014	126	206.6	61.0%	9,428.70	38.5%
2015	218	395.6	55.1%	18,446.30	43.2%
2016	74	95.9	77.2%	5,934.50	54.7%
2017	121	183.2	66.1%	9,411.20	46.0%
2018	58	84.3	68.8%	5,195.60	53.7%
2019	69	104.0	66.3%	6,108.70	49.5%
2020	20	32.2	62.2%	1,706.60	48.4%

This table shows that most of the time spent in Load Bin 0 occurs without any electric generation being conducted with over half of the CO_2 emissions being emitted as well.

Elizabeth Lawson – 55:28

Lives west of Morgantown but can see Longview from the top of her property. Longview Power should not be allowed to increase their greenhouse gas emissions under the proposed ACE rule. This permit application would allow them to increase their CO_2 emissions by 59

[55] WV DEP-DAQ, Engineering Evaluation of R13-3495, October 8, 2020, page 27.
[56] 40 CFR §60.5755a(a)(1)

pounds per megawatt hour and continue increasing emissions by four tenths of a percent in future years. Why do they need to increase emissions? Is this just to benefit investors? Will Longview's proposed emission rates include the averages from the years before they installed pollution control equipment? This is not acceptable. We have to reduce greenhouse gas emissions. Please deny this permit application. It does not create jobs and benefits no one, but far away investors.

DAQ's Response to Ms. Lawson's Comments

The baseline period used to develop the bin limits was selected to only include the time after Longview Power had installed and implemented the additional BSER technologies that were not part of the unit's original design. See the DAQ's Response to Ms. Rosser's Comments for additional information on the reasons for the increase in emissions.

> Section 5.7 of 45 CSR 13 states:
> (t)he Secretary **shall issue such permit** or registration unless he or she determines that the proposed construction, modification, registration or relocation will violate applicable emission standards, will interfere with attainment or maintenance of an applicable ambient air quality standard, cause or contribute to a violation of an applicable air quality increment, or be inconsistent with the intent and purpose of this rule or W. Va. Code § 22-5-1, et seq., in which case the Secretary shall issue an order denying such construction, modification, relocation and operation. (emphasis added).

There is no evidence that Longview will not meet all applicable emission standards, will interfere with attainment or maintenance of any ambient air quality standard, cause a violation of an applicable air quality increment or in any other way be inconsistent with 45 CSR 13 or W. Va. Code § 22-5-1, et seq., therefore, the DAQ cannot deny this permit.

Clinton Crackel, CoalZoom.com and Saving Coal – 57:41

Don't oppose the use of coal. Extremely valuable resource. Take coal plants and modify them with up to date technology to capture and divert virtually all of the emissions and convert those emissions into industrial, agricultural and household products. Would not invest in solar or wind power.

DAQ's Response to Mr. Crackel's Comments

No response required.

Joe Robinson – 1:02:06

Been involved with combustion and emission chemistry. Sulfur dioxide is 100 percent harmless. Carbon dioxide is not detrimental to our planet. Only two real pollutants sulfuric acid and nitrogen oxide. Coal is a blessing. Oil and gas are a curse.

DAQ's Response to Mr. Robinson's Comments

No response required.

Jason Bostic, West Virginia Coal Association – 1:08:23

Complement and commend work of the Division of Air Quality in developing the permit application.

DAQ's Response to Ms. Bostic's Comments

No response required.

Stuart Spencer – 1:12:45

From Arkansas. Supports Division of Air Quality's work on this permit.

DAQ's Response to Ms. Spencer's Comments

No response required.

Duane Nichols, Mon Valley Clean Air Coalition – 1:17:26

Scientific greenhouse gas effect. Water vapor from burning coal contributes to global warming. Obstructs the views to the community. Analysis doesn't take into account other impacts. Longview already receiving a tax break from Monongalia County. Longview has an opportunity to reduce emissions in the coming years. BSER candidate technologies applied to coal-fired EGUs are to lower carbon dioxide emissions from such units, that is the principle here. That is not happening in this analysis.

DAQ's Response to Mr. Nichols' Comments

The standard set in the permit is based on the application of the BSER candidate technologies. The emission guidelines allow the states to consider other factors. The data used to establish the bin limits included the time the unit operated with other HRI implemented. Had there been additional feasible BSER candidate technologies that could be applied at Longview Power, the reduction in emissions would have been reflected in the developed standard. As documented in the engineering evaluation[57], that was not the case for Longview Power because there were no additional feasible BSER technologies that had not already been implemented at Longview Power.

What local government does to attract or retain companies in their jurisdiction, such as tax breaks, does not fall under the purview or jurisdiction of the DAQ.

See the DAQ's Response to Ms. Rosser's Comments for additional information on the reasons for the increase in emissions.

Kayla Kessinger – 1:23:51

Member of West Virginia House of Delegates. Comments in support of Longview Power and permit.

DAQ's Response to Ms. Kessinger's Comments

No response required.

Ashley Deem – 1:26:23

Echoes many comments in support of Longview Power and the permit.

DAQ's Response to Ms. Deem's Comments

No response required.

Rupie Phillips – 1:27:12

Represents southern West Virginia coalfields as a member of West Virginia State Senate. Complements Longview Power.

DAQ's Response to Ms. Phillips' Comments

No response required.

Greg Thomas – 1:30:29

Taxpayer, small business owner. Positive thing for our state.

DAQ's Response to Ms. Thomas' Comments

No response required.

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[57] WVDEP-DAQ, Engineering Evaluation for R14-3495, October 8, 2020, page 19.

Evan Hansen, House of Delegates – 1:32:48

Trying to figure out what is going on here where you have members of the Coal Association asking DEP to grant a voluntary permit and to be the first in the country to regulate carbon dioxide. Things seem to be flipped on their head. Also trying to figure out from DEP, what is the rush? Why has this permit application been submitted now? Especially when the DEP rule has not even been approved yet. There has been mention of Senate Bill 810 that passed the Legislature last session. That bill requires DEP to propose a legislative bill for consideration during the 2021 Legislative Session, but that hasn't happened yet. Rules often change dramatically on their way to the Legislature. That rule hasn't even hardly begun its journey yet. Why has Longview invested so much time and resources into its permit application when it is not required to do so? Why are so many groups lining up behind a voluntary permit for carbon dioxide emissions to address climate change even before the rule has been approved by the Legislature. Again, my two questions for the DEP, what's going on here and what's the rush?

DAQ's Response to Mr. Hanson's Comments

West Virginia Code and 45CSR13 require that DAQ render a final decision on each application within 90 days once the application is determined to be complete.[58, 59] Thus, the DAQ is obligated to make a final decision on all complete applications in a timely fashion.

During the 2020 Legislative Session, the West Virginia Legislature approved Senate Bill 810, which requires the DEP to develop and submit a partial plan to the U.S. EPA by September 1, 2020 should any EGU owner/operator elect to voluntarily prepare to move forward with a compliance plan for one or more of their EGUs with the ACE Rule.[60] Longview Power submitted a permit application on June 1, 2020 with the intent to use the permit as a means to establish a CO_2 standard for their EGU as a voluntary compliance plan as allowed in Senate Bill 810. The DAQ has made every effort to satisfy the mandate set in the bill and in 45CSR13.

The federal regulation listed several forms that U.S. EPA would accept as a state plan for states to establish or adopt an emission guideline promulgated by U.S. EPA, which includes permits.[61] Regardless of the form used by a state, the state plan or partial state plan must demonstrate that it meets the requirements set forth in the emission guidelines and other requirements set forth by the U.S. EPA Administrator.

As result of Mr. Hanson's Comments, Mr. Steven Nelson, Chief Executive Officer for Longview Power, provided the following response.

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[58] W. Va. Code § 22-5-11(d).
[59] 45 CSR §13-5.7.a
[60] West Virginia Code §22-5-20, Air Pollution Control Act, March 25, 2020.
[61] 40 CFR 60.27a(g)(2)(ii).

On July 8, 2019, the United States Environmental Protection Agency (U.S. EPA) published the Affordable Clean Energy rule (ACE) consisting of emission guidelines for greenhouse gas (GHG) emissions from existing electric utility generating units (EGUs) under the Clean Air Act (CAA), section 111(d)at 84 Fed. Reg. 32520. In this rulemaking, the U.S. EPA also finalized new implementing regulations that apply to ACE and any future emission guidelines promulgated under CAA § 111(d). The U.S. EPA promulgated the ACE regulation under 40 C.F.R. Part 60, Subpart UUUUa, Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units and the implementing regulations under 40 C.F.R. Part 60, Subpart Ba, Adoption and Submittal of State Plans for Designated Facilities.

The federal emission guidelines inform states on the development, submittal, and implementation of State Plans to establish performance standards for GHG emissions from certain coal fired EGUs. The U.S. EPA determined that heat rate improvement (HRI) is the best system of emission reduction (BSER) for reducing GHG, specifically carbon dioxide (CO_2) emissions from existing coal fired EGUs meeting the applicability criteria.

Any State with one or more designated facilities that commenced construction on or before January 8, 2014 is subject to ACE and is required to submit a State Plan to the U.S. EPA that implements the emission guidelines of 40 C.F.R. Part 60, Subpart UUUUa. West Virginia has one or more designated facilities that meet the applicability criteria and therefore must develop and submit a State Plan(s) to the U.S. EPA. These plans must also be supported by state permits, of which Longview R13-3495 meets that requirement.

Although states are given flexibility on when to implement the ACE Rule, beginning the implementation of this technically complex rule for a single member of a large fleet nearly 17 months after a the Rule's promulgation does not constitute a "rush." It is also important to note that West Virginia Senate Bill 810, which was referenced by the commenter, did not just required the West Virginia DEP to prepare a legislative rulemaking to address how the Rule would be implemented across the fleet, it required the submittal of a complete or partial State Plan by September 1, 2020, which is what gave rise to the partial/segmented plan development for the Longview plant.

Moreover, the need to reduce carbon footprint while maintaining adequate reliability and resilience in the country's electric power supply is directly addressed in the basic form of the ACE rule. The value of coal-fired generation in a lower carbon future is to secure reliability and resilience in way that no other technology can supply – including batteries. The recent experience in California, growing concerns in SPP, MISO and PJM, and the history of Germany's renewable energy experiences have demonstrated the need for an effective "all-the-above" energy strategy that adequately values and retains the thermal coal fleet. If we are to ensure that coal can continue to meet this challenge, optimizing coal in terms of affordability, reliability, environmental compliance is necessary. The cornerstone of that goal in the context of both the ACE Rule and power market viability is efficiency. As the country's most efficient coal fired facility, Longview is an ideal candidate to demonstrate a viable, practical and legal means of attaining the goal of best achievable CO_2 emissions, while ensuring the affordability, reliability and resilience of our power supply."

Jordan Burgess – 1:36:04

Voiced support for the permit application by Longview Power and ACE Rule.

<u>DAQ's Response to Mr. Burgess' Comments</u>

No response required.

Questions and Answers Phase of the Public Meeting – 1:37:55

Question from Duane Nichols:

I would like to ask whether the coal source is relevant at all to the proceedings of our West Virginia DEP, whether the fuel in terms of its quality, in terms of its carbon to hydrogen ratio, is relevant? I recognize that Longview has gone through a radical change in the quality of its fuel over lifetime. It used really fine coal to come in on a conveyor belt and used a coal that was a high ash or high mineral matter coal. Now, after a few years of using Cumberland mined coal, it is a very different coal. It has better BTU value, it has much, much less mineral matter. It seems to me, this is relevant, yet I did not see that in the fact sheet. Thank you.

<u>DAQ's answer by Ed Andrews:</u>

Thank you, that is a very good question. You are absolutely right; the coal quality very much affects the CO_2 rate. It affects the parasitic load of the unit. And these are all very important factors. To address that issue, we developed the provision to allow for a coal adjustment factor to adjust the standard based on fuel switching.

Question from Jim Kotcon:

As I review the draft permit, it does not appear to have an expiration date. Does DEP plan to have one and have they considered limiting this permit to something like six or twelve months so that a final rule can be adopted by the Legislature?

<u>DAQ's answer by Ed Andrews:</u>

DAQ permits issued under State Rules 13, 14, and 19 do not have expiration dates. The one exception is temporary permits issued under Rule 13. As long as the source continues to operate under the terms and conditions of the permit and makes no physical or operational changes, the permit remains valid.

Only operating permits issued under Title V (Rule 30) have expiration dates after 5 years. Longview Power will be required to incorporate the terms and conditions of R13-3495 into its Title V Operating Permit.

Question from Jim Kotcon:

Quick follow up, does that mean that this would basically regulate Longview for the life of the plant?

<u>DAQ's answer by Ed Andrews:</u>

Essentially, unless there are other regulatory actions taken by U.S. EPA that revises emission guidelines.

Question from Angie Rosser:

Some questions posed in the comments tonight, I was wondering if those will be addressed in a written response or should those be addressed now? I am thinking of mainly Dr. Kotcon's questions and Delegate Hansen's questions.

<u>DAQ's answer by Ed Andrews:</u>

If they want to pose those questions. Those are part of the official record as comments regarding the application. We are obligated to provide a written response to those. If they want to ask them again during this phase, we will try to provide answers to some of them.

Question from Jim Kotcon:

I'm actually dying to hear the answers to Delegate Hansen's questions. What's going on and what's the rush? More specifically, why is Longview asking for the permit?

<u>DAQ's answer by Ed Andrews:</u>

> We can't speculate exactly why Longview – it is basically a voluntary application. There is no requirements that we have under the Air Pollution Control Act or the Clean Air Act to deny the application because there is no regulatory rule on West Virginia's part requiring a source like Longview to submit an application. So, it is truly all voluntary. Why the big rush – I can't answer that question myself. I am just assigned the application to review it.

Summary of the Responses

Several of the commenters noted the CO_2 limits were increasing over time and felt that the emission rates should be established to reduce CO_2 emissions from present levels. The DAQ must work within the constraints of the emission guidelines set forth in the ACE rule and the authority granted to the DAQ via the West Virginia State Code and air quality rules.

The conclusion that there is no potential for further HRI by applying BSER to Longview Power 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 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.[62]" 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 Btu/kWh[63]. The heat rate for Longview Power from the NEEDS_v6 database is 8,904 Btu/kWh[64] and, therefore, is one of the Group 1 most efficient coal-fired EGUs in the country as identified by U.S. EPA.

Longview Power is a young unit (e.g. less than 10 years old) when compared with the rest of the coal-fired EGU fleet in the U.S. Natural unit degradation will occur. Neither Longview Power nor the DAQ can prevent this from occurring or precisely predict what the unit degradation rate will be in the future; however, the DAQ has adequately justified its inclusion and development of the UDAF in both the Engineering Evaluation and in this Final Determination document.

Several of Longview Power's other HRIs involve monitoring critical pieces of equipment as part of its own Operations and Maintenance practices. The purpose of these improvements (monitoring programs) is to identify failures or degradation earlier so that proper outage planning can be effective in restoring the performance of these systems to maintain the unit's overall heat rate. These measures do not improve the unit's heat rate but allow Longview Power the opportunity to identify equipment issues while operating rather than conducting inspection outages to identify the problem. Thus, Longview Power will be able to minimize the time that a piece of equipment is operating in a degraded or impaired operation and directly reinvest in the unit where equipment needs attention.

---

[62] 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

[63] *Ibid.*, Page 1-13.

[64] https://www.epa.gov/sites/production/files/2020-10/needs_v620_10-05-20_0.xlsx

.

The DAQ believes that U.S. EPA's intention for the emission guidelines in the ACE Rule is geared toward older EGUs (e.g., over 25 years of age) to improve their heat rate by implementing the BSER candidate technologies, which will reduce CO_2 emissions. Some of the technology that was included in the Longview initial construction is more advanced than what U.S. EPA determined as BSER.

Setting a less complex standard would result in one of two situations. Either the standard would not be constraining today or would be unreasonable in the future. Longview has elected to start complying with the limits in this permit starting in 2021, which is three and half years ahead of the schedule set in the ACE Rule.

CHANGES TO THE DRAFT PERMIT

The DAQ determined that no changes to the draft permit are necessary after reviewing and responding to all of the comments received.

NOTIFICATIONS

Upon the Director's acceptance of this final determination, a copy of the final determination and final permit will be posted on the DAQ's website, which is at:

https://dep.wv.gov/daq/permitting/Pages/NSR-Permit-Applications.aspx

Additionally, a copy of the final determination and permit will be emailed to the applicant, each commenter, U.S. EPA and all attendees of the October 27th public meeting.

FINAL DETERMINATION

It is the view of the writer that after consideration of all comments received, all available information indicates the Longview Power LLC application to establish a voluntary carbon dioxide emissions standard for its coal-fired EGU near Maidsville, Monongalia County, West Virginia, should meet the emissions limitations and conditions set forth in the permit. It is, therefore, the recommendation of the undersigned that the WVDEP-DAQ issue Permit R13-3495 to Longview Power LLC.

Edward S. Andrews

Digitally signed by Edward S. Andrews
Date: 2020.12.23 13:19:07 -05'00'

Edward S. Andrews, P.E.
Engineer

Appendix A

Of

Final Determination for R13-3495

Tables of the Monthly CO_2 Rates from 2019 through 2nd Quarter 2020

And

Descriptive Statistics of the Monthly Data

Table 1A - List of the Monthly CO_2 Rates of the suggested shorten baseline period

Shorted Baseline Period	LB-1	LB-2	LB-3	LB-4	LB-5
2019	lb of CO2/MWh-Net				
Jan	**2,069**	**2,093**	**1,899**	**1,896**	**1,869**
Feb				**1,909**	**1,852**
Mar	**2,129**	**2,057**	**1,999**	**1,920**	**1,884**
Apr			**2,030**	**1,953**	**1,894**
May	**2,032**	**1,945**	**1,969**		**1,880**
Jun	**2,373**	**2,032**	**1,988**	**1,937**	**1,882**
Jul			**1,947**	**1,928**	**1,884**
Aug	**2,203**	**1,934**	**2,013**	**1,969**	**1,914**
Sep	**2,090**	**2,055**	**1,954**	**1,950**	**1,885**
Oct			**1,995**	**1,954**	**1,903**
Nov	**2,130**	**2,068**	**2,038**	**2,031**	**1,913**
Dec			**1,994**	**1,983**	**1,915**
2020					
Jan			**2,035**	**1,979**	**1,920**
Feb			**2,001**	**1,980**	**1,920**
Mar	**2,132**	**2,086**	**2,026**	**1,964**	**1,920**
Apr	**2,112**	**2,061**	**1,991**	**1,943**	**1,877**
May	**2,219**	**2,077**	**2,016**	**1,964**	**1,903**
Jun	**2,050**	**2,012**	**1,984**	**1,918**	**1,867**

Table 2A – Descriptive Statistics of the Load Bin from the suggested Shorten Baseline Period

Load Bin	LB-1	LB-2	LB-3	LB-4	LB-5
Mean (lb/MWh- Net)	2,140	2,038	1,993	1,952	1,893
Standard Error	29.07391	16.2746	8.686419	7.512851	4.934106
Median (lb/MWh- Net)	2,129	2,057	1,995	1,952	1,890
Standard Deviation (lb/MWh- Net)	96	54	36	32	21
Sample Variance	9298.213	2913.488	1282.716	1015.973	438.2173
Kurtosis	2.724655	0.405797	1.723216	1.025533	-0.94505
Skewness	1.492306	-1.22246	-1.12849	0.494319	-0.23421
Range (lb/MWh- Net)	342	159	139	135	69
Minimum (lb/MWh- Net)	2,032	1,934	1,899	1,896	1,852
Maximum (lb/MWh- Net)	2,373	2,093	2,038	2,031	1,920
Count	11	11	17	18	18
Confidence Level(95.0%)	64.7807	36.26207	18.41439	15.85073	10.41005

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Jennings, Laura M

From: Ernest, Nicole D
Sent: Monday, December 28, 2020 9:49 AM
To: Andrews, Edward S
Cc: McKeone, Beverly D
Subject: Response to Comments for Longview Power, LLC's Permit R13-3495
Attachments: 061-00134_EVAL_13-3495.pdf; 061-00134_PERM_13-3495.pdf

You are receiving this email because you took part in the West Virginia Department of Environmental Protection – Division of Air Quality public participation process, in accordance with 45 CSR 13-8.8, for Longview Power, LLC's Permit Application R13-3495. You either submitted written comments in a timely fashion, made oral comments during the public meeting on October 27, 2020, or registered and attended the public meeting held on October 27, 2020.

Attached to this email are the final determination, which includes the DAQ's response to all written and oral comments, and the final permit.

Should you have any questions about these documents, please contact Ed Andrews at 304-926-0499 extension 41244 or email at Edward.s.andrews@wv.gov.

Jennings, Laura M

From: Ernest, Nicole D
Sent: Monday, December 28, 2020 10:00 AM
To: Andrews, Edward S
Cc: McKeone, Beverly D
Subject: CORRECTION: Response to Comments for Longview Power, LLC's Permit R13-3495
Attachments: 061-00134_FinalDetermination_13-3495.pdf

All,

Please find attached the Final Determination with was not included with the original email.

Nicole Ernest
NSR Permitting Secretary

From: Ernest, Nicole D
Sent: Monday, December 28, 2020 9:49 AM
To: Andrews, Edward S <Edward.S.Andrews@wv.gov>
Cc: McKeone, Beverly D <Beverly.D.Mckeone@wv.gov>
Subject: Response to Comments for Longview Power, LLC's Permit R13-3495

You are receiving this email because you took part in the West Virginia Department of Environmental Protection – Division of Air Quality public participation process, in accordance with 45 CSR 13-8.8, for Longview Power, LLC's Permit Application R13-3495. You either submitted written comments in a timely fashion, made oral comments during the public meeting on October 27, 2020, or registered and attended the public meeting held on October 27, 2020.

Attached to this email are the final determination, which includes the DAQ's response to all written and oral comments, and the final permit.

Should you have any questions about these documents, please contact Ed Andrews at 304-926-0499 extension 41244 or email at Edward.s.andrews@wv.gov.

Longview Power LLC
Draft Permit R13-3495
Comments Received

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Jennings, Laura M

From: Joe <robinson@actcom.com>
Sent: Monday, October 26, 2020 12:23 PM
To: Andrews, Edward S
Subject: [External] Longview Power Comments

CAUTION: External email. Do not click links or open attachments unless you verify sender.

26 OCT 2020

TO: Edward S, Andrews

I am attaching my written comments to this email.

Joe Robinson
TEL: 1-617-734-9900
Email: robinson@actcom.com

President Trump's most important and least publicized accomplishment is transforming America from being the slaves to Arab oil to being the Masters of the World's oil

The most painful picture for us Americans was the picture of President Obama bowing down to the King of Saudi Arabia

BOSTON - President Trump succeeded to make us the Masters of the World's oil by creating millions of high paying jobs in the coal and oil and subsidiary industries.

Most people don't realize that 80% of a country's fuel is used to produce the electricity for the country. The remainig 20% is sufficient for all of the cars, trucks, industrial uses and the fuel needed to heat buildings.

President Trump was aware that contrary to conventional wisdom, coal emissions are cleaner than the emissions from the other two fuels, oil and gas.

The are two major pollutants and three harmless gases that are emitted from the fuels that produce electricity. The two major pollutans are sulfuric acid (also known as acid rain) and nitrogen oxides.

Industrial oil emits both pollutants, sulfuric acid and nitrogen oxides. Natural gas emits nitrogen oxides the pollutant that cost Volkswagen $30 Billion.

But coal is the cleanest fuel because it does not emit either pollutant.

The three harmless gases are water vapor, sulfur dioxide and carbon dioxide.

The EPA has known since 1978, when Professor Herbert Schimmel of the Albert Einstein Medical School published his 14 years of research, that sulfur dioxide is totally harmless.

And the people who are saying that carbon dioxide is harmful to our planet are committing blasphemy.

There are billions of human beings and billions of animals on this earth. The average human and the average animal exhales more than 2 pounds of carbon dioxide every day and we have been doing this for thousands of years.

To say that this material that we are exhaling is harmful to our planet is saying that the Good Lord is so incompetent that our breathing is destroying the world that he created and sustains.

Have you noticed that the same people who are badmouthing carbon dioxide are not telling Cocal Cola, Budweiser, Pepsi, Miller and Coors to stop putting carbon dioxide in their beverages?

Hilary Clinton admitted that her not knowing that coal emissions are the cleanest emissions cost her the election.

With coal producing our electricity, our oil exports are stabilizing our balance of payments while controlling oil prices.

Even more important, no President of the United States will ever have to bow down again to the King of Saudi Arabia.

What is probably causing an increase in average temperatures is the water vapor which is being emitted from all of the combustion processes. Did you know that each gallon of gasoline, diesel fuel and home heating oil emits 1,350 gallons of water vapor? This water vapor increases the humidity.

The humidity does not allow the evenings to cool down because it retains the heat from the day. Once the temperatures in the evening do not cool down the average temperature over the 24 hour day is going to be higher.

This is another advantage of coal. To produce the same amount of heat, coal emits half of the water vapor that oil emits and only 1/3 of the water vapor that natural gas emits.

President Trump has done more for the economics, environment and health of America than any prior President.

Jennings, Laura M

From: Reger-Nash, Bill <wreger@hsc.wvu.edu>
Sent: Wednesday, October 28, 2020 5:24 PM
To: Andrews, Edward S
Subject: [External] I strongly Object to increase in gas emissions from the Longview Power Plant

Categories: Red Category

CAUTION: External email. Do not click links or open attachments unless you verify sender.

Dear Sir,

As a public health professional, I am appalled by the proposed addition to the Longview Power Plant. Greenhouse gas emissions are choking our atmosphere and our planet. We have myriads of environmental problems associated with these issues. Please do not allow Longview to spew more toxic emissions into our air, waterways, and ultimately our soil. The draft permit enables such increases. This is unconscionable. Deny this expansion.

/ **Bill Reger-Nash, EdD**

Professor Emeritus
School of Public Health
West Virginia University
Morgantown, WV 26506-9190
C: 304-685-6740

wreger@hsc.wvu.edu
publichealth.hsc.wvu.edu/BillRegerNash/
publichealth.hsc.wvu.edu

Morgantown Pedestrian Safety Board

Walk 30 to 60 minutes daily.
Feel the Power of Half an Hour! gn

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[External] Longview Power Comments

Monday, November 9, 2020   3:01 PM

Subject	**[External] Longview Power Comments**
From	Betsy J. Lawson
To	Andrews, Edward S
Sent	Saturday, October 31, 2020 6:21 PM

CAUTION: External email. Do not click links or open attachments unless you verify sender.

To Mr. Edward Andrews:

Affordable 'Clean' Energy is an ironic title for a regressive rule that would permit INCREASED greenhouse gas pollution.

Quite apart from the immorality of the rule replacing the Clean Power Plan in face of all the climate ruction we are already experiencing, one wonders at the haste of Longview in trying to acquire this permit in advance of the Inauguration, when a differing administration might have them reverse what they had just invested time and money in.

Worse, they want this permit granted by the WV DEP before the rule has even been finalised and passed by the Administration. This seems like buying a 'pig in a poke', but a pig that does not even exist - perhaps a shell game might be a better analogy. How can this be a legal procedure on the part of Longview? or the DEP?

Doubtless Longview has the provision that permits extra emissions when not operating at full capacity clearly in mind. This, as inevitably coal energy will become less profitable as alternative energy becomes more so, as it already is. On top of this economic crutch, an increase of 0.4% per annum after 20 years would allow an increase to 108% from the starting point, more if compounded - instead of less, as the future habitability (and economic stability) of the world requires.

Moreover Longview included years of operation without their current more efficient emissions controls when proposing their averaged emissions, ensuring the ceiling be well above their current emissions. This means that they are applying to emit above their current pollution levels, on top of the proposed increase. What is the point of having installed such, to propose to run them at 'half-cock' - apart from selling electricity more cheaply to their customers outwith West Virginia, which will suffer the poorer air quality, but where the permit would come from.

We should be drastically reducing CO_2 and SO_2 emissions, not increasing them. How many more warnings/ super-expensive disasters do we need.   Hurricanes Katrina, Sandy, Matthew, Harvey, alone totalled $340+ billion.   Wildfires in California, 2007, 2018, 2019, 2020, Colorado, 2012, 2020, Washington, 2015, 2020, Smoky Mountains 2016, and the Midwest crop failure in 2019, are further indicators of what is increasingly to come. How much of this does the taxpayer cover? The 10 hottest years on record have all occurred since 2005, the hottest 5 since 2015.

This permit should not be considered.   It is illegitimate, blindly profit-driven and socially irresponsible.

Sincerely,

Stephen Lawson

Morgantown, WV

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Jennings, Laura M

From: Stephen Lawson <s.panolawson@gmail.com>
Sent: Sunday, November 1, 2020 11:53 AM
To: Andrews, Edward S
Subject: [External] Re: Longview Power Comments

CAUTION: External email. Do not click links or open attachments unless you verify sender.

Please ignore previous, unsigned comment, and forgive my unfamiliarity with Email procedures. This one I hope is proper:

Please disregard my identical commentary already sent on my behalf by my wife, Elizabeth Jaeger at bjaegerart@gmail.com. using her email address, so perhaps accredited to her, and regarded as 'stuffing'.

Dear Edward S. Andrews, this is my comment on the 'Pollution Permit Application on behalf of Longview 1:

Affordable 'Clean' Energy is an ironic title for a regressive rule that would permit INCREASED greenhouse gas pollution.

Quite apart from the immorality of the rule replacing the Clean Power Plan in face of all the climate ruction we are already experiencing, one wonders at the haste of Longview in trying to acquire this permit in advance of the Inauguration, when a differing administration might have them reverse what they had just invested time and money in.

Worse, they want this permit granted by the WV DEP *before* the rule has even been finalised and passed by the Administration. This seems like buying a 'pig in a poke', but a pig that does not even exist, yet - perhaps a shell game might be a better analogy. How can this be a legal procedure on the part of Longview? or the DEP?

Doubtless Longview has the provision that permits *extra* emissions when not operating at full capacity clearly in mind. This, as inevitably coal energy will become less profitable as alternative energy becomes more so, as it already is. On top of this economic crutch, an increase of 0.4% per annum after 20 years would allow an increase to 108% from the starting point, more if compounded - instead of less, as the future habitability (and economic stability) of the world requires.

Moreover Longview included years of operation without their current more efficient emissions controls when proposing their averaged emissions, ensuring the ceiling would be well above their current emissions. This means that they are applying to emit *above* their current pollution levels, on *top* of the proposed increase. What is the point of having installed such, to propose to run them at 'half-cock' - apart from selling electricity more cheaply to their customers outwith West Virginia, which will suffer the poorer air quality, but where the permit would come from.

We should be drastically reducing CO_2 and SO_2 emissions, not increasing them. How many more warnings/ super-expensive disasters do we need. Hurricanes Katrina, Sandy, Matthew, Harvey, alone totalled $340+ billion. Wildfires in California, 2007, 2018, 2019, 2020, Colorado, 2012, 2020, Washington, 2015, 2020, Smoky Mountains 2016, and the Mid-West crop failure in 2019, are further indicators of what is increasingly to come. How much of this does the taxpayer cover? The 10 hottest years on record have all occurred since 2005, the hottest 5 since 2015.

This permit should not be considered. It is illegitimate, blindly profit-driven and socially irresponsible.

Stephen Lawson. 1213 Gallus Road, Morgantown, WV 26501.

On Sun, 1 Nov 2020 at 11:25, Stephen Lawson <s.panolawson@gmail.com> wrote:

> *Please disregard my identical commentary already sent on my behalf by my wife, Elizabeth Jaeger at bjaegerart@gmail.com. using her email address, so perhaps accredited to her.*
>
> *Dear Edward S. Andrews, this is my comment on the 'Pollution Permit Application on behalf of Longview 1:*
>
> Affordable 'Clean' Energy is an ironic title for a regressive rule that would permit INCREASED greenhouse gas pollution.
>
> Quite apart from the immorality of the rule replacing the Clean Power Plan in face of all the climate ruction we are already experiencing, one wonders at the haste of Longview in trying to acquire this permit in advance of the Inauguration, when a differing administration might have them reverse what they had just invested time and money in.
>
> Worse, they want this permit granted by the WV DEP *before* the rule has even been finalised and passed by the Administration. This seems like buying a 'pig in a poke', but a pig that does not even exist, yet - perhaps a shell game might be a better analogy. How can this be a legal procedure on the part of Longview? or the DEP?
>
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>
> Moreover Longview included years of operation without their current more efficient emissions controls when proposing their averaged emissions, ensuring the ceiling would be well above their current emissions. This means that they are applying to emit *above* their current pollution levels,

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This permit should not be considered. It is illegitimate, blindly profit-driven and socially irresponsible.

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Jennings, Laura M

From:	James Kotcon <jkotcon@gmail.com>
Sent:	Monday, November 9, 2020 4:05 PM
To:	Andrews, Edward S
Subject:	[External] Comments on Draft Permit R13-3495, Longview Power Greenhouse Gases
Attachments:	Longview greenhouse gas permit-comments-2020.docx

CAUTION: External email. Do not click links or open attachments unless you verify sender.

See attached letter. Thank you.

jim Kotcon
Conservation Chair
304-594-3322 (home)

SIERRA CLUB

Sierra Club
West Virginia Chapter
P.O. Box 4142
Morgantown, WV 26504

Nov. 8, 2020

Ed Andrews
West Virginia Department of Environmental Protection
Division of Air Quality
601 57th Street, SE
Charleston, WV 25304
Via e-mail to: Edward.S.Andrews@wv.gov

RE: Comments on draft permit # R13-3495, Longview Power greenhouse gas permit

Dear Mr. Andrews:

Please accept the following comments on behalf of the approximately 2600 members of the West Virginia Chapter of Sierra Club. We recognize that this draft permit is voluntary, and that the rules for greenhouse gas limits (45-CSR-44) have not yet been approved in final form by the Legislature. However, we hope you will consider these comments as this is the first permit of its kind in West Virginia and may set precedents for others that follow when rules are finalized.

The Sierra Club is among many organizations challenging the EPA's Affordable Clean Energy rule as it is inadequate to address the serious threats to our climate posed by greenhouse gas emissions from fossil fuels. If that rule is overturned, we expect much more stringent emissions reductions would be required. Likewise the state rule, 45-CSR-44, is similarly inadequate and may yet be modified by the Legislature. The comments below are offered to assist your review based on the information in the Longview application, the draft permit, the accompanying Engineering Evaluation (EE), and the rules as currently promulgated, and should not be construed as the Sierra Club's position on this or other permits if the current rules change.

Section 4.1. Limitations and Standards.

Longview proposed a standard of 2,049 lb CO2/MWh (net) on a 3-year rolling annual average basis. They proposed to exclude data during start-ups, shutdowns and malfunctions (SSM) or during hours when unit load is <40 %. They further propose to increase the allowable emissions by 0.4 % annually to account for equipment efficiency losses over the life of the plant.

Their proposed standard of 2,049 lb CO2/MWh was derived by calculating the mean emissions rate for the last 6 years (1,943 lb), then adding 3 Standard Deviations (3 x 35 lb). This is a standard that would allow 2 % greater emissions than occurred in 2014, **before** the Heat Rate Improvements (HRIs) were installed at Longview, and nearly 8 % higher than the current (i.e., baseline) performance. That level also includes low load and impaired operations that occurred during the baseline period. That clearly cannot serve as a performance standard for a rule intended to use HRIs to reduce greenhouse gas emissions.

The draft permit identifies several "Load Bins" to specify emissions limits at various operating loads. One of the most effective means of limiting emissions from plants that were designed as base load units is to ensure that operators limit operations to those periods when the plant can operate at optimal design loads, rather than as load-following units that would operate a significant proportion of the time in less efficient, higher-emitting Load Bins. We are concerned that the draft permit would therefore likely result in an even greater increase in emissions than discussed above as the plant ages and becomes less competitive in the market, just at the time when significant reductions are needed.

Specific issues include:

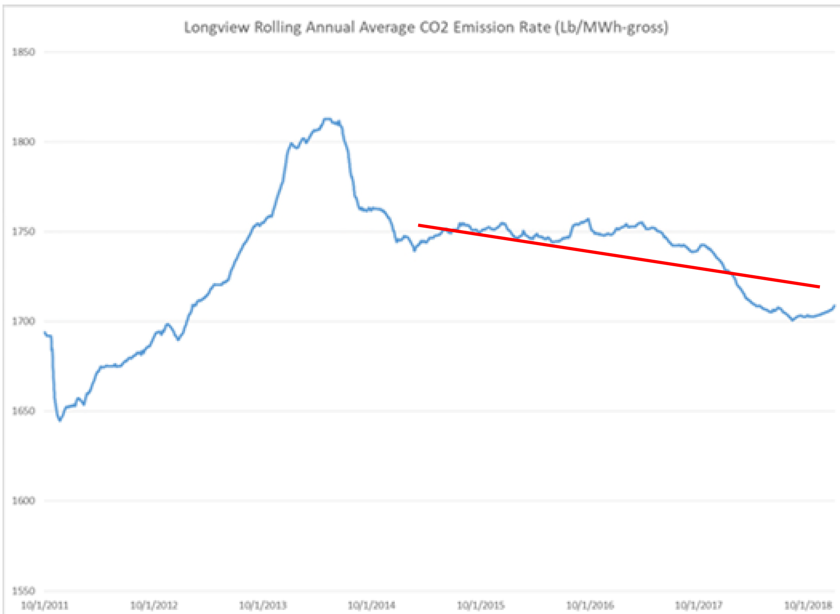
1) First, it is unclear what authority WV-DEP has to issue this permit, or why Longview is voluntarily seeking it. The proposed rule (45-CSR-44) will be reviewed in the 2021 session of the Legislature, so why is this permit needed now? If this is intended to "grandfather in" certain greenhouse gas emissions and allow lifetime emissions for the plant, that seems highly unlikely to prevail, as climatological evidence clearly shows much more dramatic restrictions on emissions is needed. If there is some other economic incentive to obtain this permit, it is not clear from the application submitted by Longview, and that certainly does not give WV-DEP legal authority to assist Longview. This is particularly important as this is the first one of its kind in West Virginia, and it may set precedents for all other plants that come after this. Furthermore, the public is not able to comment in an informed way on the drivers for this permit. **We recommend that WV-DEP analyze the precedent-setting implications of this permit, and more clearly disclose their current legal authority and the rationale for this permit, as well as any potential conflicts of interest from Longview in seeking the permit.**

2) The Engineering Evaluation (EE) for the draft permit indicates that the limits were established using annual emissions averages, plus two Standard Deviations. I have not found anything in the federal ACE rule nor in the proposed 45-CSR-44 state rule to require that either a 3-Standard-Deviation or 2-Standard Deviation variation be considered. Incorporation of statistical variability is appropriate to reflect random, uncontrollable variability in the production process or in measurement of the emission rate. The EE discusses variation in hourly and monthly emission rates. Because the proposed standard is based on annual average emissions variations over shorter time periods are irrelevant. The annual average emission rates at Longview are a compilation of thousands of individual measurements over the year and so, address random variability over shorter time frames. The variation in annual performance over time largely reflect matters, such as technology upgrades, ongoing maintenance schedules and operating loads that are within the control of the operator and are not random events. Other variables, such as variation in annual average cooling water temperature, that are not in LVP's control and could theoretically affect the annual average emission rate are ordinarily quite small and have not been separately determined by WVDEP. The historic emission rates at Longview (as measured and reported by the operator to EPA) demonstrate that the plant, even at 10 years of age, has sustained and maintained rolling annual average emission rates below 1750 lb/MWh (gross) or 1925 lb/MWh (net).

3) These data (See Figure One, below) also show that, after initial startup issues were resolved, the emission rate improved over time (as some – but by no means all - of the recommended HRI technologies were adopted) rather than degrading. It should also be understood that these rates include operation in all Load Bins and were achieved at a time when

Longview's operator was under no obligation to maintain a specific emission limitation and may have found it to be economically rewarding to operate in a fuel-inefficient manner. Thus, instead of seeking improvements in performance and reductions in emissions, the proposed limits in the draft permit would allow significant increases in greenhouse gas emissions.

Figure One. Longview Rolling Annual Average Emission Rates[1]



4) The use of 2014-2018 data to calculate the average and Standard Deviation inflates the emissions because 2014 occurred before installation of certain HRIs, such as the Neural Network Upgrade (June 2015) and the Intelligent Combustion (Fall 2018). It certainly inflates the estimate of Standard Deviation because it includes higher rates from those years with lower rates in 2019-2020 in that calculation, Indeed, because of the increased Standard Deviation that results, the inclusion of the lower emission rates in 2017 and 2018 actually increases the proposed emission rate over what it would have been had only the pre-modification date (2014 to 2016) been employed. **It is inappropriate to establish a standard for operation with HRIs by including emission data from years of operation without those HRIs.** Yet the EE clearly states (page 22, repeated on page 23) that:

"the entire baseline period was used for developing the standards for all of the bins".

The most appropriate approach would be to estimate the variability in emissions based solely on 2019 and 2020 data, because those are the only data for emissions with all HRIs in place. The mean and the variance can be estimated from the hourly emissions data from those years. Thus, the mean for all emissions in 2019 should be 1899 lbs/MWh or lower.

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[1] Source: emissions data reported by Longview to USEPA www.ampd.epa.gov.

5) Furthermore, the 2019-2020 data represent a mean over hours of operation that include all of the operating loads. Figure 8 of the EE indicates that Longview operated at something less than 90 % of the time, and Figure 12 suggests that the plant was operating in Load Bin 0 (<40 % capacity) approximately 50-100 hours in 2019 when would have the highest emissions rates, and had a significant number of operating hours in Load Bins 1-4 in 2019-2020. Table 4 (page 23) implies that emissions limits were calculated using emissions data for the respective Load Bins, however, those means do not match the levels in the draft permit. **<u>It is inappropriate to establish a standard for operation with HRIs during periods of peak performance (full capacity loads) by including emissions data from hours of operation at lower unit loads, when emissions per MWh are higher.</u>**

6) Section 4.1.1.b. The provision that the plant can operate for up to 180 days at the Level 2 emissions limits, and "shall be deemed approved…" places the burden on WV-DEP to affirmatively verify if the incident qualifies as a Level 2 event and provides no means for the public to determine whether WV-DEPs determinations are correct or to challenge any WV-DEP determinations. The provisions give too much incentive to Longview to declare such events for relatively minor problems, problems that the O&M practices should prevent and too much of an administrative burden of WV-DEP. There is no limit in the draft permit on how often a Level 2 event might be declared, nor whether overlapping events might allow Longview to operate indefinitely with Level 2 limits. **<u>We recommend that the hours of Level 2 operation be restricted to less than 8 hours per event (so as to allow for shut down of the unit) to prevent unwarranted emissions from running at Level 2 indefinitely.</u>**

7) Section 4.1.1.c. The Unit Degradation Adjustment Factor (UDAF) allows a 0.4 % increase per year, with a 0.7% recovery every five years. These values appear to be based on Longview's analysis of historic data for similar plants within the region. Since none of these units are under any obligation to maintain a maximum emission rate, these data only tell us what has been done in the absence of a rule that is intended to change past practices. There does not appear to be any analysis of the extent to which new HRI technology or Operating and Maintenance Practices (O&M) programs were used in this fleet-wide analysis, yet the ACE rule clearly requires such on-going O&M to demonstrate Heat Rate Improvement compliance. **<u>Including emissions rates and UDAFs for plants that do not implement the needed O&M is inappropriate</u>**. The assumption that Unit Degradation is inevitable has not been demonstrated, and is directly contradicted the Longview performance data over the last 10 years and by the new legal obligation to achieve and maintain a specified heat rate or adopt Heat Rate Improvements.

8) The UDAF also allows the emissions rate increases to compound year-over-year, thus allowing much larger annual increases in later years. There does not appear to be any evidence to justify this, and Figure 20 shows a linear, not logarithmic, increase (even in plants not required to implement Heat Rate Improvements). **<u>Since the goal is to limit greenhouse gas emissions, we recommend that the permit use lower rates for UDAF, provide better justification for any non-zero UDAF, and apply them only to the base year, rather than using a compound interest approach as currently proposed.</u>**

9) WV-DEP has apparently uncritically accepted Longview's assertions regarding Heat Rate Improvement technologies. For example, it appears that the intelligent soot-blowing system performed better than EPA's estimated range would suggest. However, there is no evaluation as to whether the "intelligent combustion system" is a BSER-level of application of the technology. No data concerning the performance of the heaters and duct leakage was reviewed by DEP. Nor did DEP evaluate what technical improvements were available. DEP offers a number of general conclusions regarding O&M practices, but does not provide any specifics as to the nature and rigor of Longview's O&M practices, how they differ from those at other plants and why they are BSER. The list of practices that should be evaluated is lengthy, well beyond what Longview described in their application. **We recommend that WV-DEP seek an independent analysis of HRI technologies.**

10) WV-DEP has apparently accepted Longview's contention that they will continue to operate as a base load plant (page 48 of the EE), however, this ignores the abundant evidence of market realities in our region. Use of coal as a fuel for generating electricity is declining, and the Capacity Factor of plants is declining as well, as demonstrated in Figure 19 of the EE. Most projections show that this rate of decline will accelerate in coming years. That means it is realistic to expect an increased frequency of operations in Load Bins 1-4, and especially, an increase in Load Bin 0, as the plant shuts down more often. The goal of regulating greenhouse gas emissions is to prevent just such increases. **We recommend that total emissions per year be capped, to prevent Longview from "gaming" the system and dramatically increasing greenhouse gas emissions by operating in inefficient Load Bins or engaging in excessive shut downs and start-ups. Furthermore, WV-DEP should require Longview to evaluate feasibility of additional Heat Rate Improvement technologies in these reduced unit Load Bins.**

Thank you for the opportunity to comment.

Sincerely,

James Kotcon

James Kotcon
Conservation Chair

Jennings, Laura M

From: Duane Nichols <duane330@aol.com>
Sent: Monday, November 9, 2020 4:16 PM
To: Andrews, Edward S
Subject: [External] Comment on Longview Draft Permit # R13-3495

CAUTION: External email. Do not click links or open attachments unless you verify sender.

…………… MON VALLEY CLEAN AIR COALITION …………

Ed Andrews
West Virginia Department of Environmental Protection
Division of Air Quality
601 57th Street, SE
Charleston, WV 25304
Via e-mail to: Edward.S.Andrews@wv.gov

RE: Comments on draft permit # R13-3495, Longview Power greenhouse gas permit

Dear Mr. Andrews:

Our Mon Valley Clean Air Coalition has followed Longview from the very beginning.

Recall they promised to use WV coal, but are using Pennsylvania coal. They promised to consume not water from the Monongahela River, but are using such for their evaporative cooling activity. They promised to have zero discharge to the environment, but they pump wastewater down into an underground coal mine.

Now the WV-DEP is proposing more concessions to Longview Power LLC so as to permit them to pollute the environment, even more than otherwise. How in God's name can you look at yourself in the mirror if you are the enabler of increased pollution? The WV-DEP has a responsibility to DECREASE pollution, NOT INCREASE IT, where have you been? In other words, who is running our state government?

This is a letter of protest on behalf of the residents of the Ft. Martin community who are exposed to multiple coal fired power plant and 300 diesel trucks per day transporting coal up the long narrow Ft. Martin hill. They are like most all other West Virginians who are unaware of the illogical activity involving this Draft Permit.

On behalf of the Bakers Ridge community, the Stewartstown community, the Forks of Cheat Forest, the Pt. Marion community, and indeed on behalf of the students and staff of the University High School, this draft permit is an environmental insult. All are subjected to the emissions of the Longview and Ft. Martin power plants. All experience the fine particulates, the acidic emissions, the free radical reactants, the vapor clouds and the anxieties of unknown trace materials.

Because this draft permit would establish excessive and unnecessary carbon dioxide emissions, all other emissions will also be increased. The intent of climate change regulations is to reduce all greenhouse gases. Even the water vapor and the particulates contribute to this, so must be considered.

This DRAFT is PREMATURE. There is no current level of regulation or control. In fact, the operation of Longview isn't needed, not necessary, since our PJM has plenty of generation. This company is not operating in as a public service, rather as a private operator for private gain, I.e. to maximize profits. The WV-DEP has no such mandate, rather you should function in the public interest.

This DRAFT PERMIT needs to be withdrawn as untimely, out of place, not logical and possesses strong political overtones. The motivation for it within state government has not been revealed, so the public interest is being abused. The reputation of the WV-DEP is on the line.

Duane G. Nichols, Ph.D.
Mon Valley Clean Air Coalition
330 Dream Catcher Circle
Morgantown, WV 26508

Duane330@aol.com
304-599-8040

Jennings, Laura M

From: Thomas T. Lampman <Thomas.T.Lampman@wvago.gov>
Sent: Monday, November 2, 2020 2:14 PM
To: Andrews, Edward S
Subject: [External] Longview Power Comments
Attachments: 2020-10-27 AG Comments to DEP re Proposed Air Quality Permit 13-3495 (M0393829xCECC6)-c1.pdf

CAUTION: External email. Do not click links or open attachments unless you verify sender.

Mr. Andrews,

Please find attached a written copy of the comments given by Attorney General Patrick Morrisey on the Longview Power Proposed Permit.

Thank you.

Thomas T. Lampman
Assistant Solicitor General
OFFICE OF THE ATTORNEY GENERAL
OF WEST VIRGINIA

Office: (304) 558-2021
Direct: (681) 313-4554

State of West Virginia
Office of the Attorney General

Patrick Morrisey
Attorney General

(304) 558-2021
Fax (304) 558-0140

October 27, 2020

Comments of Attorney General Patrick Morrisey

to the Department of Environmental Protection Office of Air Quality

on Proposed Air Quality Permit 13-3495

Thank you for the opportunity to speak here today, and to address a very important topic. It's a topic that matters a lot to me, because in a sense it's laying the groundwork for a foundation for years.

By adopting the proposed permit we're here to discuss today, West Virginia can finally start to build a solid regulatory foundation that our agencies and our power plants can rely on for years to come. We aren't out of the woods, but this does represent a turning point that I and others had to fight very hard to reach.

As many of you know, one of my first priorities as Attorney General was fighting back against the Obama Administration's ill-conceived and illegal War on Coal. West Virginia coal was being attacked on a lot of different fronts, and one of the major fronts was the one we're here to talk about today. The problematic Obama-era Section 111(d) guidelines for existing coal-fired power plants.

Obama's Clean Power Plan was cloaked as a 111(d) guideline, but it was unlike any guideline a State had been given before. The balance between federal and state powers is critical to the normal operation of 111(d)—States rely on the federal EPA to set guidelines that state agencies implement for each source. The CPP's real purpose was to force state agencies like West Virginia's DEP to impose performance standards on coal plants that were, frankly, unachievable.

EPA wanted to co-opt DEP's authority, and use it to force coal-fired plants to subsidize their competitors—and eventually to shut down altogether.

My Office led the charge in stopping that assault in its tracks, and we secured the first-of-its-kind stay of the CPP from the Supreme Court before it ever went into effect. And since that time, we've been working closely with the Trump Administration's EPA to replace the CPP with a fair, effective, and legal set of guidelines.

This has been a long, time-intensive, and resource-intensive process. After extensive notice and comment on both the repeal of the CPP and on the appropriate scope of guidelines to issue in its place, EPA issued replacement guidelines in July of last year.

State Capitol Building 1, Room E-26, 1900 Kanawha Boulevard East, Charleston, WV 25305

The permit we're here to discuss today implements these guidelines. And I know folks from Longview will explain in detail what this entails from a technical standpoint. The technical standpoint is important—that's how we know that the efficiency improvements EPA is calling for strike the right balance between being achievable by the source and being beneficial for the environment.

I am impressed by the technical facts here, and by what Longview shows us about what a modern coal plant can achieve in terms of fuel efficiency and emissions reductions.

But as your Attorney General, I think what I can speak to most directly is the broader significance of being where we are today. Because the fact that we finally have guidelines to implement, the fact that we're in this position at all, that is in itself the culmination of a nearly six-year battle.

I'm obviously incredibly proud of the work we've done stopping unlawful regulations from taking root, and I'm encouraged about the future. But the reality is that there was still a lot of uncertainty involved in getting to this point. We've known for a long time that the CPP was unlawful, but any lawyer can tell you that you don't always win just because you're right.

So even as we held CPP back, West Virginia still felt the constant pressure that comes from having something so destructive hanging over your head. The shadow it cast made it all the more difficult to see a plan for the future.

And that is why today matters so much. By beginning to implement the fair and lawful guidelines established by the Affordable Clean Energy Rule, we're finally beginning to develop some certainty.

It's easy to see why our coal fleet benefits from having defined rules that they can rely on, but establishing a clear method of implementation benefits the State as well. It helps tremendously that, as regulators, we've started to pull together the resources and analysis that go into reviewing these types of permits.

I know that each permit will be different, but given all the sweat equity that the team at DEP has put into taking these first steps, I know that having that baseline means a lot. None of this takes away from the work that's left ahead of us, but the work that has been done already is impressive.

We've all gone so long without having anything to really rely on in this area. That's why I just wanted to take a few moments to emphasize how significant it is that we've made it to this point, and how meaningful it is for everyone to finally be establishing reliable standards and a reliable framework.

I hope that this process can continue to move quickly, collegially, and collaboratively. And I want to note that my Office can be a resource as we move through the process of both finalizing this permit and of submitting our state plan to EPA.

We are relying on this process for West Virginia's future. We want to get it right. Today, West Virginia takes another step forward and will be relying on this outcome as it develops additional strategies to maximize the use of coal in an environmentally sound manner.

We urge you to move forward with this application.

Thank you.

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Jennings, Laura M

From: Billman, Lauren <Lauren.Billman@mail.house.gov>
Sent: Wednesday, October 28, 2020 11:42 AM
To: Andrews, Edward S
Subject: [External] Longview Power Comments
Attachments: Longview Power Comments.docx

CAUTION: External email. Do not click links or open attachments unless you verify sender.

Hi Edward,

Please find Congresswoman Miller's comments attached. Let me know if you have any questions.

Thanks,

Lauren Billman
Legislative Director | Congresswoman Carol Miller (WV-03)
1605 Longworth House Office Building
(202) 225-3452

COMMENTS FROM CONGRESSWOMAN CAROL D. MILLER
PUBLIC HEARING ON LONGVIEW POWER LLC, PERMIT APPLICATION 13-3495
WEST VIRGINIA DEPARTMENT OF ENVIRONMENTAL PROTECTION
OCTOBER 27, 2020

Good evening. My name is Carol Miller and I represent West Virginia's Third Congressional District, which encompasses southern West Virginia. I wanted to ensure I spoke today in support of Longview's permit application to comply with the U.S. Environmental Protection Agency's Affordable Clean Energy rule.

The destructive Obama-Era Clean Power Plan decimated our state's coal industry. The widespread and devastating impacts of this rule cost the livelihoods of many and shuttered our small towns and communities. That is why I was pleased when President Trump and his Administration replaced this failed policy with the Affordable Clean Energy rule. This rule empowers West Virginia and ensures that thermal coal mines in my district in Mingo, Boone, Logan, and Wyoming counties can continue to provide good paying jobs for our miners. Furthermore, this rule allows us to continue to power our homes, schools, and places of work with reliable baseload energy and, ultimately, helps promote America's energy diversity.

I want to thank my colleagues in the West Virginia Legislature and Governor Justice for acting swiftly under SB 810 to ensure that the Affordable Clean Energy rule can be implemented throughout the state. I also want to compliment Secretary Caperton and Laura Crowder at the West Virginia Department of Environmental Protection for their work on this effort.

The Longview Power plant is the cleanest and most efficient coal-fired power plant in North America. Longview provides affordable and reliable energy to more than 500,000 homes. No matter how cold the weather gets, Longview Power ensures that those of us in Appalachia can keep our homes connected. The plant also supports 150 good-paying jobs, which is important now, more than ever.

Recovering from the War on Coal is an effort that takes every level of government as well as a committed partnership with the private sector. Approving Longview Power's application to comply with the Environmental Protection Agency's Affordable Clean Energy rule is necessary to ensure that we can continue to support good paying jobs as well as reliable and affordable energy. West Virginia has a proud coal heritage, and through innovation and investment, we can ensure it will remain part of our future.

Jennings, Laura M

From: Crowder, Laura M
Sent: Tuesday, October 27, 2020 1:40 PM
To: Andrews, Edward S; McKeone, Beverly D; Hammonds, Stephanie E
Subject: FW: [External] Letter supporting Longview permit application
Attachments: 10262020 WV Delegation letter to WVDEP on Longview permit under ACE SIGNED.pdf

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From: Caperton, Austin <Austin.Caperton@wv.gov>
Sent: Tuesday, October 27, 2020 1:31 PM
To: Ward, Harold D <Harold.D.Ward@wv.gov>; Mandirola, Scott G <Scott.G.Mandirola@wv.gov>; Crowder, Laura M <Laura.M.Crowder@wv.gov>
Subject: Fw: [External] Letter supporting Longview permit application

Austin Caperton

Cabinet Secretary WVDEP

Driven by **E**mployee **P**ride

304-926-0440

Our Core Values: Professionalism - Integrity - Education

Knowledge - Expertise - Credibility - Public Service

From: Cone, Travis (Capito) <Travis_Cone@capito.senate.gov>
Sent: Tuesday, October 27, 2020 1:21 PM
To: Caperton, Austin <Austin.Caperton@wv.gov>
Cc: Tomlinson, Adam (Capito) <Adam_Tomlinson@capito.senate.gov>
Subject: [External] Letter supporting Longview permit application

CAUTION: External email. Do not click links or open attachments unless you verify sender.

Secretary Caperton,

Hope you and yours are well.

Please find attached a letter from Senator Capito, Congressman McKinley, Congressman Mooney, and Congresswoman Miller in support of Longview's permit application under your implementation of the ACE rule interpretation of Clean Air Act Section 111. I will also drop a copy in the mail.

Thanks for your consideration and let me know of any questions. Good luck with the public e-hearing this evening.

Best,
Travis

C. Travis Cone
Senior Energy Adviser
Senator Shelley Moore Capito (R-WV)
172 Russell Senate Office Building (SR-172)
Washington, DC 20515
202-224-6472
travis_cone@capito.senate.gov

Congress of the United States
Washington, DC 20515

October 27, 2020

Austin Caperton
Secretary
West Virginia Department of Environmental Protection
Executive Office
601 57th Street, SE
Charleston, WV 25304

Dear Secretary Caperton,

As elected officials in the West Virginia congressional delegation, we write in support of approval by the Department of Environmental Protection (WVDEP) of Permit Application #13-3495 submitted by Longview Power, LLC for certification under the state's implementation of Section 111 of the Clean Air Act and the Environmental Protection Agency's (EPA) Affordable Clean Energy (ACE) rule.

The ACE rule will meaningfully reduce the emission of greenhouse gases while abiding the legal requirements of Section 111 of the Clean Air Act (CAA) for an "inside the fence line" regulatory approach addressing the thermal efficiency of a power plant through the "Best System of Emissions Reduction" standard.

We commend your efforts and that of the Department to ensure that West Virginia is the first state to implement the ACE rule and seek approval from EPA for its regulatory program. In so doing, West Virginia has again demonstrated its leadership as an energy and electricity exporting state.

As you know, the first application under West Virginia's updated regulatory program is Longview Power, one of the most modern and efficient coal-fired power plants in the Western Hemisphere. A 700-megawatt plant, Longview utilizes an advanced supercritical boiler technology to achieve a best-in-class operational heat rate of 8,750 Btu/kWh. Longview's unique design, operations, and maintenance parameters, reflected in its application, satisfy the BSER standard under the ACE rule.

We support timely approval of Longview's application, in accordance with all applicable laws, regulations, and internal Department guidance. Thank you for your consideration of this request.

Sincerely,

Shelley Moore Capito

Shelley Moore Capito
United States Senator

David B. McKinley

David B. McKinley, P.E.
Member of Congress

Alex X Mooney

Alex X. Mooney
Member of Congress

Carol D. Miller

Carol D. Miller
Member of Congress

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Longview Power Public Meeting Questions
October 27, 2020 – 6:00 p.m.

<u>Angie Rosser, West Virginia Rivers Coalition – 16:40</u>

Trying to understand how BSERs are determined. If they are determined by some type of national survey average of what the status quo is. That is not good enough. Wrong direction. Bottom line is to improve this permit so it reduces and not increases emissions.

<u>Stephen Nelson, Longview Power – 20:30</u>

Thanks everyone for attending and weighing in.

<u>Leah Barbor, Moms Clean Air Force – WV – 21:38</u>

Opposes this rule and mirrors some of West Virginia Rivers concerns. Greenhouse gas emissions have adverse effects on our health and welfare. EPA has a legal obligation to limit the pollution that endangers our health and welfare but the ACE Plan doesn't fulfill this legal obligation. Recognizes that energy efficiency measures have value, but they should also include emissions reductions. It is unacceptable that the draft permit would allow substantial increases in greenhouse gas emissions for years to come, growing at a rate of 24 percent every year. Baseline emission rate being 50 pounds of CO_2 per megawatt hour beyond the actual 2019 rate seems irresponsible and unnecessary.

<u>Michael Nasi, Jackson Walker LLP – 25:05</u>

Echoes Steve Nelson's comments. Will be the first national carbon dioxide limit.

<u>Michelle Bloodworth, America's Power – 30:13</u>

Speaking in support of the permit for Longview Power.

<u>Chris Hamilton, West Virginia Coal Association – 35:28</u>

Appreciates opportunity to participate in support of permit for Longview Power.

<u>Patrick Morrisey, West Virginia Attorney General – 40:43</u>

This application should be advanced. Thanks everyone for taking the time to be involved in this process. Urges to move forward.

<u>Carol Miller, Congresswoman – 46:07</u>

Speaking in support of Longview's application.

<u>James Kotcon, West Virginia Chapter of the Sierra Club – 50:10</u>

Will submit written comments before November 9. Does DEP recognize that there is absolutely no need to regulate greenhouse gas emissions except to limit climate change? This permit recognizes that that is the issue we are trying to resolve here. Given that the West Virginia Legislature has not yet approved the rules to implement the Affordable Clean Energy Act, does DEP actually have any legal authority to issue and enforce this permit? Is this the first permit under the Affordable Clean Energy Act in the U.S.? If not, what precedence does DEP rely on for this permit? If it is, is it DEP's intent to use the Longview permit for other coal-fired power plants in West Virginia? In their application Longview used data from a number of years prior to implementing some of the heat rate improvement installations in 2018, so is it appropriate to include uncontrolled emissions to calculate limits for the controlled emissions after this permit takes affect? That troubles me. Has DEP or Longview considered cofiring biomass as part of its permit? Is there any mechanism in the permit to allow or encourage the use of biomass fuels in addition to cofiring with coal? Longview assumes that the efficiency of their facility declines with age and that might seem intuitively obvious, but does DEP have any data from a modern coal-fired power plant such as Longview, one that is well maintained, to show that this is inevitable? Is there any reason to think that with proper maintenance the emissions level has to continuously increase? Has DEP when they established their six different bins recognized that a lower capacity or lower bin level seems to be increasingly likely? The U.S. Energy Information Agency concluded just this week that solar energy is the cheapest electric generation in the United States. The competitiveness of Longview seems likely to go down and what basis do we have for using these lower generating capacity load bins for estimating greenhouse gas emissions? In particular load bin 0, which is established in section 4.1.1.a.i. of the permit, has a limit of 9,864 pounds per megawatt hour. That is more than five times the emissions rate for the highest load bin 6. That bin applies whenever the plant is operating at less than 313 megawatts. So, if the plant is only operating at 40 percent of its capacity, they are allowed to let their emissions go through the roof at five times the rate. I have quite a number of other questions and I hope to ask them after.

<u>Elizabeth Lawson – 55:28</u>

Live west of Morgantown, but can see Longview from the top of her property. Longview Power should not be allowed to increase their greenhouse gas emissions under the proposed ACE rule. This permit application would allow them to increase their CO_2 emissions by 59 pounds per megawatt hour and continue increasing emissions by four tenths of a percent in future years. Why do they need to increase emissions? Is this just to benefit investors? Will Longview's proposed emission rates include the averages from the years before they installed pollution control equipment? This is not acceptable. We have to reduce greenhouse gas emissions. Please deny this permit application. It does not create jobs and benefits no one, but far away investors.

<u>Clinton Crackel, CoalZoom.com and Saving Coal – 57:41</u>

Don't oppose the use of coal. Extremely valuable resource. Take coal plants and modify them with up to date technology to capture and divert virtually all of the emissions and convert those emissions into industrial, agricultural and household products. Would not invest in solar or wind power.

<u>Joe Robinson – 1:02:06</u>

Been involved with combustion and emission chemistry. Sulfur dioxide is 100 percent harmless. Carbon dioxide is not detrimental to our planet. Only two real pollutants sulfuric acid and nitrogen oxide. Coal is a blessing. Oil and gas are a curse.

Jason Bostic, West Virginia Coal Association – 1:08:23

Complement and commend work of the Division of Air Quality in developing the permit application.

Stuart Spencer – 1:12:45

From Arkansas. Supports Division of Air Quality's work on this permit.

Duane Nichols, Mon Valley Clean Air Coalition – 1:17:26

Scientific greenhouse gas effect. Water vapor from burning coal contributes to global warming. Obstructs the views to the community. Analysis doesn't take into account other impacts. Longview all ready receiving a tax break from Monongalia County. Longview has an opportunity to reduce emissions in the coming years. BSERs applied to coal-fired EGUs are to lower carbon dioxide emissions from such units, that is the principle here. That is not happening in this analysis.

Kayla Kessinger – 1:23:51

Member of West Virginia House of Delegates. Comments in support of Longview Power and permit.

Ashley Deem – 1:26:23

Echoes many comments in support of Longview Power and the permit.

Rupie Phillips – 1:27:12

Represents southern West Virginia coalfields. Complements Longview Power.

Greg Thomas – 1:30:29

Taxpayer, small business owner. Positive thing for our state.

Evan Hansen, House of Delegates – 1:32:48

Trying to figure out what is going on here where you have members of the Coal Association asking DEP to grant a voluntary permit and to be the first in the country to regulate carbon dioxide. Things seem to be flipped on their head. Also trying to figure out from DEP, what is the rush? Why has this permit application been submitted now? Especially when the DEP rule has not even been approved yet. There has been mention of Senate Bill 810 that passed the Legislature last session. That bill requires DEP to propose a legislative bill for consideration during the 2021 Legislative Session, but that hasn't happened yet. Rules often change dramatically on their way to the Legislature. That rule hasn't even hardly began its journey yet. Why has Longview invested so much time and resources into its permit application when it is not required to do so? Why are so many groups lining up behind a voluntary permit for carbon dioxide emissions to address climate change even before the rule has been approved by the Legislature. Again, my two questions for the DEP, what's going on here and what's the rush?

Jordan Burgess – 1:36:04

Voiced support for the permit application by Longview Power and ACE Rule.

Questions – 1:37:55

Duane Nichols:

I would like to ask whether the coal source is relevant at all to the proceedings of our West Virginia DEP, whether the fuel in terms of its quality, in terms of its carbon to hydrogen ratio, is relevant? I recognize that Longview has gone through a radical change in the quality of its fuel over lifetime. It used really fine coal to come in on a conveyor belt and used a coal that was a high ash or high mineral matter coal. Now, after a few years of using Cumberland mined coal, it is a very different coal. It has better BTU value, it has much, much less mineral matter. It seems to me, this is relevant, yet I did not see that in the fact sheet. Thank you.

Ed Andrews:

Thank you, that is a very good question. You are absolutely right, the coal quality very much affects the CO2 rate. It affects the parasitic load of the unit. And, these are all very important factors. To address that issue, we developed that provision to allow for a coal adjustment factor to adjust the standard based on fuel switching.

Jim Kotcon:

As I review the draft permit, it does not appear to have an expiration date. Does DEP plan to have one and have they considered limiting this permit to something like six or twelve months so that a final rule can be adopted by the Legislature?

Ed Andrews:

There is no expiration date. Now, we can't speak about any future rule making cause we are not at the West Virginia Legislature at this time. But, we do not intend to have an expiration date on this permit.

Jim Kotcon:

Quick follow up, does that mean that this would basically regulate Longview for the life of the plant?

Ed Andrews:

Essentially, unless there is other regulatory action taken by EPA that revises emission guidelines.

Angie Rosser:

Some questions posed in the comments tonight, I was wondering if those will be addressed in a written response or should those be addressed now? I am thinking of mainly Dr. Kotcon's questions and Delegate Hansen's questions.

Ed Andrews:

If they want to pose those questions. Those are part of the official record as comments regarding the application. We are obligated to provide a written response to those. If they want to ask them again during this phase, we will try to provide answers to some of them.

Jim Kotcon:

I'm actually dying to hear the answers to Delegate Hansen's questions. What's going on and what's the rush? More specifically, why is Longview asking for the permit?

Ed Andrews:

We can't speculate exactly why Longview – it is basically a voluntary application. There is no requirements that we have under the Air Pollution Control Act or the Clean Air Act to deny the application because there is no regulatory rule on West Virginia's part requiring a source like Longview to submit an application. So, it is truly all voluntary. Why the big rush – I can't answer that question myself. I am just assigned the application to review it.

Jim Kotcon:

I understand and appreciate that. I am wondering if Longview would like to take a stab at answering that?

Stephanie:

I don't see anyone raising their hand or coming on to answer that question.

Jim Kotcon:

Thank you.

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AIR QUALITY PERMIT NOTICE AND PUBLIC MEETING SCHEDULED

Notice of Intent to Approve

On June 1, 2020, Longview Power, LLC applied to the WV Department of Environmental Protection, Division of Air Quality (DAQ) for a permit to establish a carbon dioxide emission standard for an electricity generation facility located at 1375 Fort Martin Road, Maidsville, Monongalia County, WV, at 39.7090 latitude and -79.9589 longitude. A preliminary evaluation has determined that all State and Federal air quality requirements will be met by the proposed facility. The DAQ is providing notice to the public of its preliminary determination to issue the permit as R13-3495.

This permitting action will establish a weighted carbon dioxide standard on a calendar year basis using the established load bin limits below and the hours of operation in each load bin during the year.

Load Bin	Load Bin Range (MWh G)	Normal Operation Level 1 Limit* (lb CO_2/MWh Net)	Impaired Operation Level 2 Limit** (lb CO_2/MWh Net)
LB-0	0-313	9,864^G	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

G = Gross generation in terms of MWh gross electricity generation.
* = Normal Operations above the minimum stable load of the emission unit.
** = Impaired Operations above the minimum stable load that has been approved by the Director for a specified duration of time. Impaired Operation means that the unit can operate below normal efficiency due to unavoidable equipment failure.

After the initial compliance year, the above limits will be increase by 0.4% annually due to unit degradation with a recovery rate that decreases the limit by 0.7% once every five years. In the year 2046, these limits will be fixed thereafter at the following limits:

Load Bin	Load Bin Range (MWh G)	Normal Operation Level 1 Limit* (lb CO_2/MWh Net)	Impaired Operation Level 2 Limit** (lb CO_2/MWh Net)
LB-0	0-313	10,523^G	N/A
LB-1	>313-407	2,379	2,617
LB-2	>407-501	2,249	2,474
LB-3	>501-595	2,187	2,406
LB-4	>595-689	2,136	2,349
LB-5	>689	2,089	2,298

The DAQ has scheduled a public meeting for 6:00 p.m. on Tuesday, October 27, 2020. The public meeting will be held virtually to prevent the spread of COVID-19 in accordance with the Governor's Safer at Home Order and the WVDEP COVID-19 Policy. Instructions for providing written comments and for providing oral comments at the virtual public meeting are provided below.

The purpose of the public review process is to accept public comments on air quality issues relevant to this determination. Only written comments or comments presented orally at the scheduled public meeting, will be considered prior to final action on the permit. All such comments will become part of the public record.

Written comments must be received by 5:00 p.m. on Monday, November 9, 2020:

- Email written comments to Edward.S.Andrews@wv.gov with "Longview Power Comments" in the subject line, or
- Mail hard copy comments to Edward Andrews, WV Department of Environmental Protection, Division of Air Quality, 601 57th Street, SE, Charleston, WV 25304.

Public meeting participation:

- Members of the public can participate online or listen via telephone. Participant pre-registration is required by 5:00 p.m. on Tuesday, October 27, 2020. To register, please complete the participant registration form at https://apps.dep.wv.gov/daq-register/133495. A confirmation email will be sent with information on how to join the public meeting. If you do not have internet access and want to register, please contact Sandie Adkins (ext. 41243) or Stephanie Hammonds (ext. 41263) at (304) 926-0475 by 5:00 p.m. on Monday, October 26, 2020.

Additional information, including copies of the draft permit, application and all other supporting materials relevant to the permit decision may be obtained by contacting the engineer listed below or downloaded at:

https://dep.wv.gov/daq/permitting/Pages/NSR-Permit-Applications.aspx

Edward Andrews
WV Department of Environmental Protection
Division of Air Quality
601 57th Street, SE
Charleston, WV 25304
Telephone: 304/926-0499, ext. 41244
edward.s.andrews@wv.gov

west virginia department of environmental protection

Division of Air Quality
601 57th Street, SE
Charleston, WV 25304-2345
Phone: 304 926 0475 • Fax: 304 926 0479

Austin Caperton, Cabinet Secretary
www.dep.wv.gov

ENGINEERING EVALUATION/FACT SHEET

BACKGROUND INFORMATION

Application No.:	R13-3495
Plant ID No.:	061-00134
Applicant:	Longview Power LLC
Facility Name:	Longview Power LLC
Location:	Maidsville
NAICS Code:	221112
Application Type:	Construction
Received Date:	June 1, 2020
Engineer Assigned:	Edward S. Andrews, P.E.
Fee Amount:	$1,000.00
Date Received:	June 1, 2020
Complete Date:	July 29, 2020
Due Date:	October 27, 2020
Applicant Ad Date:	July 17, 2020
Newspaper:	*Dominion Post*
UTM's:	Easting: 580.6 km Northing: 4,306.9 km Zone: 17
Description:	This action is to establish a carbon dioxide emission standard using the Best Standard of Emission Reductions (BSERs) outlined in the Emission Guidelines of 40 CFR 60, Subpart UUUUa for a Pulverized Coal Fired Steam Generating Unit (PC-Boiler).

PERMITTING ACTION SUMMARY

This action will not change the facility classification under any of the Air Permitting Programs under the Federal Clean Air Act or the State of West Virginia's Air Pollution Control Act. Longview Power LLC (LVP) has proposed limits that account for all the carbon dioxide emissions emitted from the existing pulverized coal-fired steam generator (boiler) which is used to support the electric generating unit (EGU) at the Maidsville, West Virginia, facility.

Under Subpart UUUUa, also referred to as the Affordable Clean Energy Rule (ACE), states are required to establish a carbon dioxide emission standard for any coal-fired EGUs that commenced construction on or before January 8, 2014. The BSERs applied to coal- fired EGUs are to lower the carbon dioxide emissions from such units. The emission guidelines require the states to evaluate seven specific heat rate improvement (HRI) technologies for economic and technical feasibility. The potential HRI that can be feasibly incorporated at each EGU that would decrease the CO_2 emissions are used to establish a carbon dioxide emission standard. Other factors, such as the remaining useful life of the unit, may be considered. The end goal of improving an EGU's heat rate is to lower the fuel consumption of the unit which will reduce carbon dioxide emissions.

At the time of this application submittal, there is no statue, regulation, or rule at either the State or Federal level that specifically requires LVP to submit this application. This application is viewed by the West Virginia Department of Environmental Protection (WVDEP) - Division of Air Quality (DAQ) as voluntary on LVP's part.

DESCRIPTION OF PROCESS

LVP is an independent power producer with one generating unit participating on the PJM Interconnection. LVP operates a merchant steam to electricity (EGU) power plant near Maidsville, West Virginia. The following is a basic flow diagram of the process.

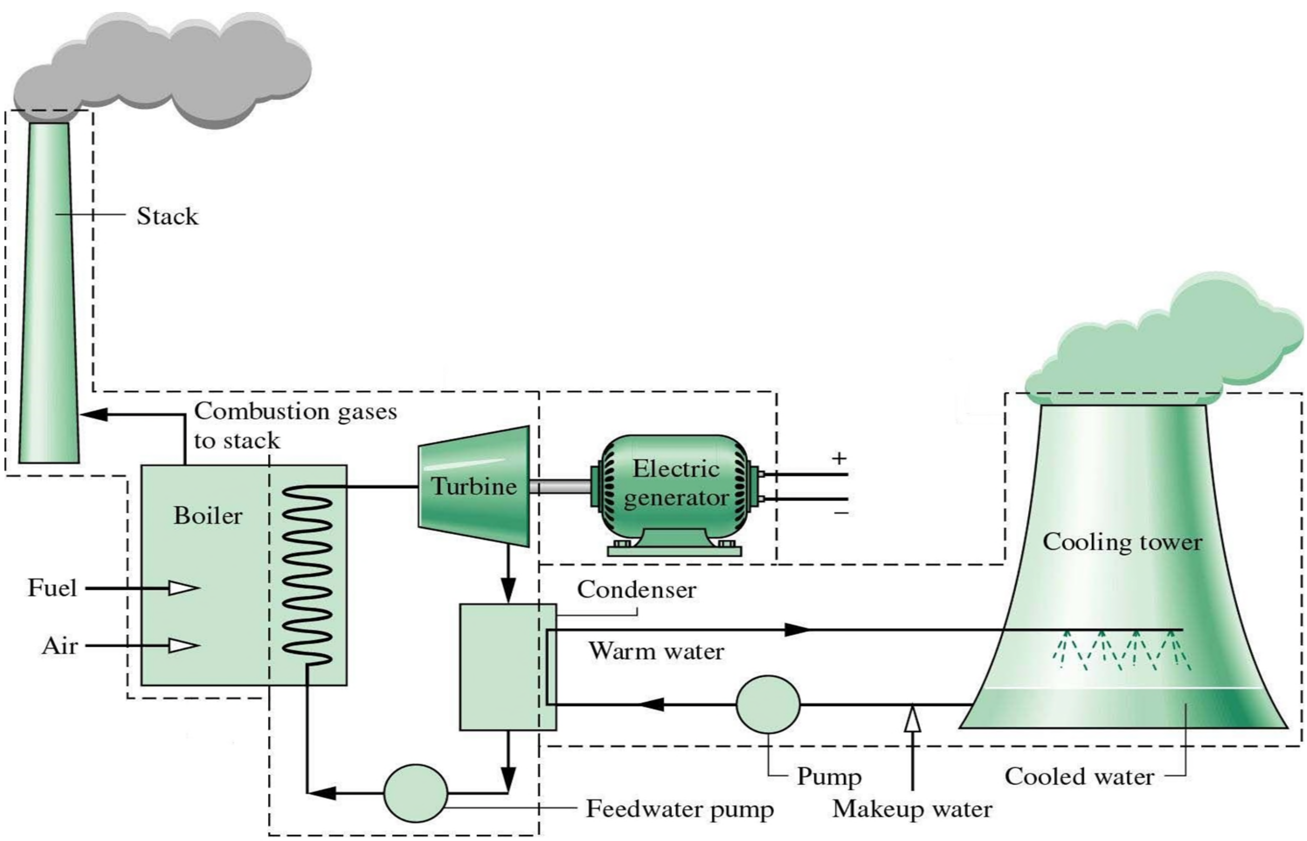


Figure 1. Process Flow Diagram

The affected unit in this application is a Foster Wheeler designed and constructed once-through, Benson low mass flux vertical tube wall-fired advanced supercritical, pulverized coal fired boiler. This unit generates steam that is routed to a Siemens Steam Turbine SST-6000.

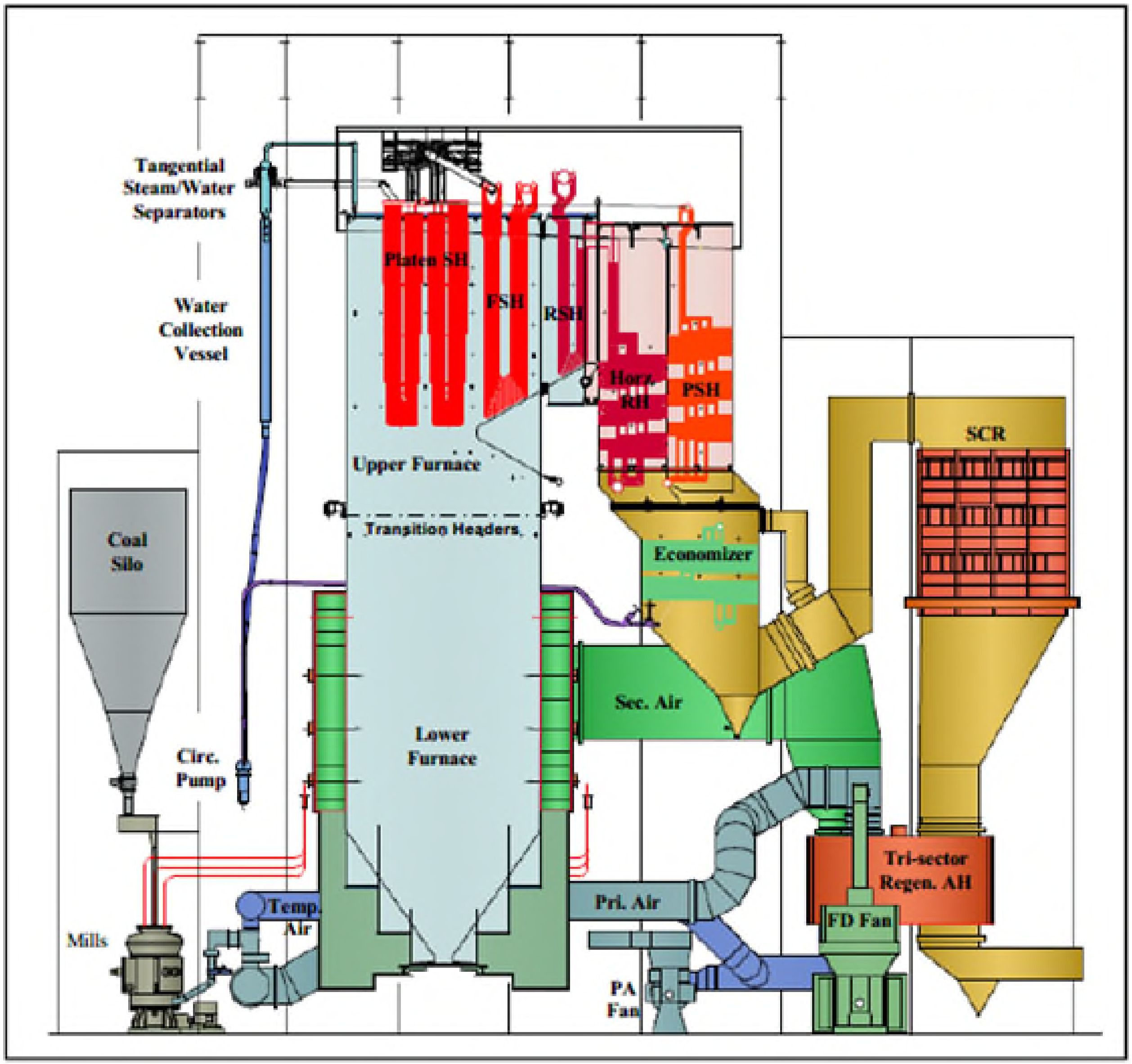


Figure 2. Cut-away of LVP's Pulverized Coal Boiler

The steam generator (boiler) is a wall-fired, supercritical Foster Wheeler boiler rated at 700 MW net. The unit has six coal pulverizers that supply fuel to the boiler through an opposite wall burner arrangement. The boiler has a platen superheat surface, vertical and horizontal reheat surfaces, and a parallel back-end arrangement which splits the flue gas between the horizontal reheat and primary superheat sections.

The combustion air for the unit is preheated by two Ljungström (Banks A and B) combustion air heaters, which are located downstream of the selective catalytic reduction (SCR) control device. The air heaters transfer residual heat energy from the flue gas to the combustion air. The Ljungström type of air heater features a cylindrical shell, plus a rotor, which is packed with bundles of heating surface elements and is rotated through counterflowing air and flue gas. The rotor is enclosed by stationary housing with ducts at both ends. Combustion air flows through one half of the rotor as hot flue gas flows through the other half. Metallic leaf-type seals are used to minimize air to gas leakage and air/flue gas bypass around the rotor (See Figure 3).

Feedwater to the steam generator is supplied using three, 50% feedwater pump trains. The main feedwater pump train has a single speed motor that drives a 7/7 (seven stage), horizontal, barrel-type pump with radial impellers and single-entry. A VOITH hydraulically-geared coupling is used to vary the actual speed of the pump (pumping rate) without the use of throating or choke valves on the discharge side of the pump.

The economizer is between the horizonal reheat and primary superheat sections of the boiler and the SCR control device. The economizer transfers heat energy from the combustion exhaust gases exiting the horizonal reheat and primary superheat sections to the feedwater before it enters the furnace of the boiler. To ensure that the exhaust gas exiting the economizers is at or above the minimum operation SCR temperature of 670ºF, an economizer by-pass has been installed to allow a portion of the flue gases to by-pass the economizer.

Design main steam conditions are 1,0562°F at 3,840 psi while the design reheat steam conditions are 1,052°F at 824 psi. Figure 2 shows a side view of LVP Unit 1.

LVP Unit 1 has 52 sootblowers for cleaning the furnace walls. The unit has 70 long retractable blowers to clean the tube sections in the convection pass. Steam is used as the sootblowing medium for these blowers. The unit also has 4 air heater blowers. All blowers are controlled by the intelligent sootblowing system.

The intelligent sootblowing system is a performance-based system which uses the actual heat transfer performance of the furnace and each tube bank to direct sootblowing operations. The system integrates with all sootblower control systems including DCS-based systems and is designed for fully automatic operation of the sootblowers. The intelligent sootblowing system is composed of three major components: a detailed boiler performance model, a robust expert system, and a full-featured queuing system.

The performance model uses measured operational data and the actual design of the boiler to calculate cleanliness factors for each heat transfer section including the furnace. The model also calculates other important measures, such as furnace exit gas temperature (FEGT), boiler efficiency, and heat rate. The output from the performance model, as well as plant operational data, is sent to the expert system. The LVP intelligent sootblowing expert system is an easy-to-use and understand rule-based decision logic system. The expert system allows for the creation of different cleaning strategies for specific areas of the furnace and convection pass. The strategies cannot only determine when blowing should be initiated, but also when blowing should stop or when blowing should be paused temporarily. Once the expert system determines cleaning is needed in an area of the boiler, the sootblowers from that area are sent to the Titanium sootblowing queue for operation. The queue dynamically orders the sootblowers based on a combination of blower effectiveness and time since last operation. The effectiveness of each sootblower is based on historical data and measures how much impact a blower has on a target metric. After ordering, the queue operates the blowers until either the queue is empty, or the expert system calls for sootblowing operations to cease.

The Titanium system was initially installed in mid-2014 but was not ready for full operation until September 2015 due to instrumentation and plant operational issues. The plant rehabilitation project delayed getting the Titanium system tuned and in full-time automatic operation until mid-January 2016.

SITE INSPECTION

The writer has visited the facility several times, with the latest occurring on January 13, 2020. The main purpose of the visit was to go over the proposed siting for LVP Unit 2 (Permit Application R14-0038). On October 22, 2019, several members of the agency, which included Ms. Laura Crowder, Director of the DAQ; Ms. Laura Jennings, Technical Analyst for the Planning Section of the DAQ; Mr. Todd Shrewsbury, Engineer for the Planning Section of the DAQ; Mr. Fredrick Tipane, Technical Analyst for the Title V Permitting Group of the DAQ; Mr. Rex Compston, Engineer for the Modeling Group of the DAQ; and, the writer, met with Mr. Steve Nelson, Chief Operating Officer of LVP; Mr. Chad Hufnagel, Plant Manager of the LVP Maidsville Facility; and, Mr. Brian Hoyt, Compliance and Environment Manager of the LVP Maidsville Facility. The main purpose of the October 22 visit was to review the heat rate improvements LVP has made and understand how these improvements affect the unit performance and carbon dioxide emissions.

The facility's last full on-site inspection was conducted on September 26, 2018, by Mr. Brian Tephabock, Compliance & Enforcement Supervisor of the North Central Regional Office of the DAQ. Mr. Tephabock found the facility operating in compliance with all applicable rules, regulations, and permitted limitations. An additional site inspection of the facility was determined by the writer to be unnecessary for this permitting action.

ESTIMATE OF EMISSIONS BY REVIEWING ENGINEER

LVP currently operates a continuous emission monitoring system (CEMS) that measures the emission rates of several different pollutants, including carbon dioxide (CO_2), emitted from the PC Boiler and other process data parameters. As part of the application file, LVP included hourly CO_2 emissions data from this system from 2012 through the second Quarter of 2020.

Table 1 – Summary of the Carbon Dioxide Emissions from Longview Power

Operating Year	2012	2013	2014	2015	2016	2017	2018	2019	2020*
CO_2 Rate lb/MW-Net	1,837	1,882	1,999	1,944	1,946	1,947	1,921	1,899	1,936
CO_2 Mass Rate (tpy)	3,819,482	4,135,978	3,698,311	2,970,427	5,140,293	4,577,297	5,012,221	4,988,555	2,165,146

* Based on data from January 1 through June 30 of 2020.

REGULATORY APPLICABLILITY

At the time of filing this application, there is no West Virginia state rule or federal regulation that requires LVP to submit this application to establish a carbon dioxide emission standard based on implementing the carbon dioxide emission guidelines in Subpart UUUUa of 40 CFR 60 "Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units." EPA promulgated this subpart as a requirement for the states to develop State Plans in accordance with Subpart Ba of 40 CFR 60 to regulate carbon dioxide emissions from existing coal-fired electric utility generating units (EGUs). Therefore, Subpart UUUUa requires the states to develop plans to the EPA Administrator's satisfaction that regulates carbon dioxide emissions from coal-fired EGUs that commenced operation/construction before January 8, 2014.

For establishing the standards of performance for carbon dioxide emissions for the designated facility under Subpart UUUUa, there are seven heat rate improvement candidate technologies that need to be evaluated as to whether the designated facility could implement them and to determine the degree of heat rate improvement. These technologies are:

- Neural network/intelligent sootblowers
- Boiler feedwater pumps
- Air heater and duct leakage control
- Variable frequency drives
- Blade path upgrades for steam turbines
- Redesign or replacement of economizer
- Improved operating and maintenance practices

LVP's Heat Rate Improvement analysis (summarized in Table 2 below) is based on the EPA guidance of BSERs and the potential HRI based on a unit greater than 500 MW. In LVP's case, all the technical equipment solutions are part of the original design of the facility except for Neural

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

Table 2 Summary of Longview Power's Heat Rate

HRI Candidate	**(%) Range of HRI Potential Improvement for EGUs > 500 MW from Table 1 from Subpart UUUUa**		**Longview Target (Btu/kWh)**	
	Min	**Max**	**Min**	**Max**
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 and duct leakage control	0.1	0.4	8.8	35.2
Variable frequency drives	0.2	1.0	17.6	88.0
Blade path upgrades for steam turbines	1.0	2.9	88.0	255.2
Redesign or replacement of economizer	0.5	1.0	44.0	88.0
Improved operating and maintenance practices	0.0	2.0		
Total Potential of all the Heat Rate Improvements			202.4	765.6
Projected HR after HRI from Baseline OPM HR (Btu/kWh)			8,598	8,034
Change in HR (%)			2.3	8.7

OPM Baseline HR 8,800 Btu/kWh on a Lower Heating Value Basis.
OPM – Black & Veatch's On-Line Performance Monitoring System.

Neural Network/Intelligent Sootblowing

Typical sootblowing operations at most facilities are operated by premade 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 slag 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 will increase which affects the overall heat rate (decreases the efficiency) of the unit during sootblowing operations.

Intelligent Sootblowing systems use sensors that measure 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 are programed to activate sootblowers only in the location or section that the system determined needed to be cleaned to restore heat transfer performance of the heating surfaces (tubes and heat exchangers) of the unit.

According to Subpart UUUUa, a neural network means a computer model that can be used to optimize combustion conditions, steam temperatures, and air pollution emissions at steam generating units.

LVP installed the intelligent sootblowing system and upgraded the neural network distributed control system (DCS) in 2015. Also, LVP installed an intelligent combustion system in 2018. Babcock 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 upstream 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 has already installed these HRI technologies, no further evaluation of the technical and or economic feasibility of these technologies is necessary.

Boiler feed pumps

Subpart UUUUa does not specifically state what technological improvement(s) can be made for the boiler feed pumps. LVP had Black & Veatch (B&V) evaluate 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 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 slightly above the OEM's performance curve. This indicates that little to no degradation has occurred on any of the boiler feed pumps. B&V concluded that technology upgrades of the boiler feed pump internals are not recommended as a viable method for improving the heat rate of LVP's unit.

The writer 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 improvement for the unit.

Air heater and duct leakage control

This heat rate improvement applies at a unit using 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 electric utility steam generating units. The regenerative air heaters' most notable operating characteristic is that a small but significant amount of air leaks into the flue gas stream due to the rotary operation.

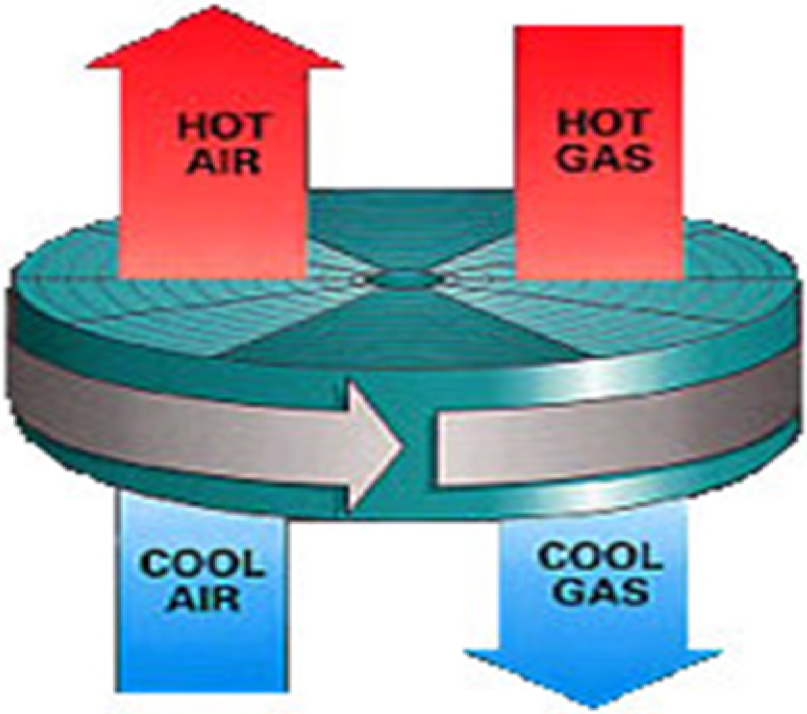


Figure 3. Diagram of Air Heater

LVP uses a regenerative style air heater on their unit. Their air heaters have a double seal design which can be adjusted while on-line. The following figure is an illustration of LVP's adjustable seal design.

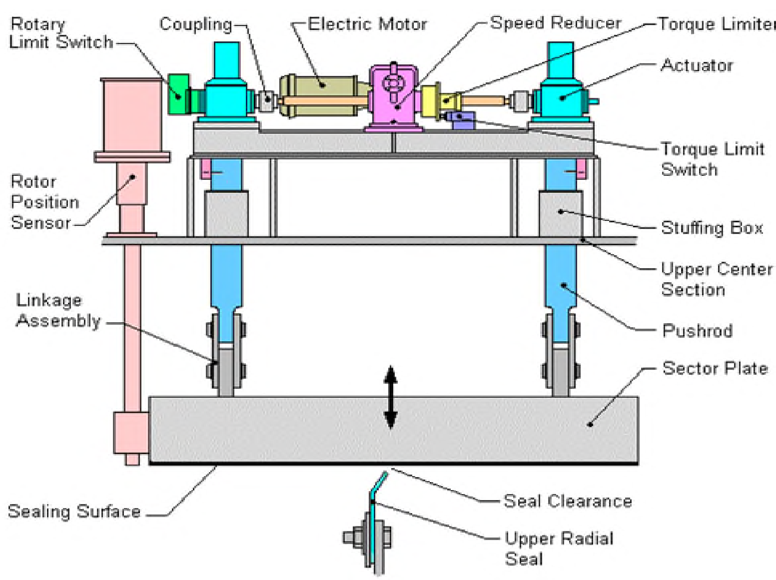


Figure 4. Diagram of LVP's Adjustable Seal Design

LVP claims that their original air heater seal design meets the intent of the HRI under Subpart UUUUa. The writer agrees with the applicant that the intent of the HRI under Subpart UUUUa was to reduce leakage through the seals and repair ductwork by replacing worn out seals, make improvements to the seal design, using better materials for the seals (i.e. from single to double seals, wear resistance materials, adjustable seals) and repair ductwork. The writer concurs that LVP has implemented the HRI technology in their unit.

Variable frequency drives

Variable frequency drive (VFD) means an adjustable-speed drive used on induced draft fans and boiler feed pumps to control motor speed and torque by varying motor input frequency and voltage. 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 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 increased electrical equipment maintenance associated with the VFD system.

VFDs on the Boiler Feed Water Pumps

LVP uses a VOITH hydraulic geared coupling to vary the actual speed of the pump (pumping rate) of each of the three boiler feed water pumps to vary the boiler feed water to the unit. Thus, the load (work) performed by the electric motor remains constant and translates to less overall wear while maintaining improved efficiency over wider motor speeds. This technology would adjust the work performed throughout the loads. At low load operations (475 MW gross), this HRI technology could reduce the auxiliary load consumption from the boiler feed water pumps by 3.9 MW. This technology does not reduce the unit's heat rate at full load conditions.

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 the maximum projected cost in the Sargent & Lundy, Coal-Fired Power Plant Heat Rate Reductions, SL-009597 Final Report, January 22, 2009. (EPA-HQ-OAR-2017-0355-21171) of $8.50 per kW adjusted to 2020 dollars from 2008. The annual operation and maintenance costs were estimated to be $9,000 for all three pumps.

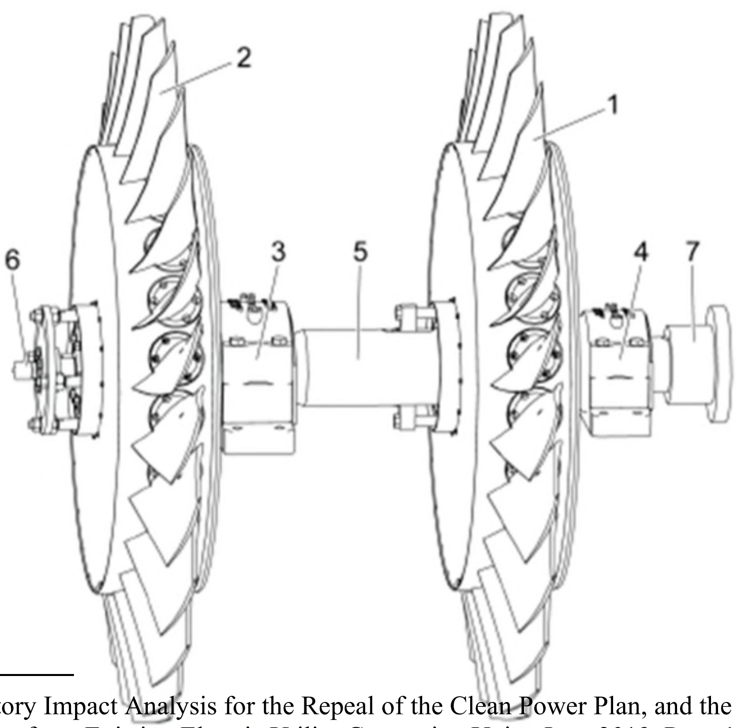
The unit only operated at loads less than 695 MW during the proposed baseline period (2016 to second Quarter of 2020) for only 10% of the operating time, which does not include startup and shutdown periods (loads less than the unit's minimum load of 313 MW gross). These pumps operate near their highest efficiency point at full load, thus there Is no potential savings at low load, even with the fluid drives still in place. Given the high capacity factor of the unit, the practical annual potential HRI is low (0.19 percent), especially given the high cost of the VFDs.

The writer concurs with LVP's evaluation that implementing this technology on the boiler feedwater pumps is not reasonable due to the projected cost.

VFDs on the Induce Draft Fans

EPA specifically mentions the application of VFD technologies on induced draft fans in the emission guidelines.[1] LVP is a balanced draft system that was designed to take into account the restrictions associated with the downstream air pollution control devices (e.g., SCRs, baghouse, wet scrubber). Thus, LVP had their induced draft and forced air fans evaluated for the feasibility of applying the VFD technology.

Based on the available information and operating data, the induced draft (ID) fan auxiliary power consumption benefit is estimated to be negligible for two fans at full load (782 MW gross) and 120 kW at low load (475 MW gross). Refer to Figure 4 illustrating the current ID fan operation with variable blade pitch control and future variable speed operation with VFDs.



[1] EPA-452/R19-003, 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, June 2019, Page 1-9

1. *Impeller 1*
2. *Impeller 2*
3. *Locating (thrust) bearing (type spherical roller bearing)*
4. *Non-locating (free) bearing (type spherical roller bearing)*
5. *Main shaft*
6. *Pitch control mechanism for Impeller 2*
7. *Coupling hub*

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Figure 5. Diagram of Axial Fan

Centrifugal fans are widely used in the power industry for boiler air control. These older and less efficient industry fans have been superseded by axial blade fans, such as installed at LVP. The use of VFD on those older centrifugal fans provides proportionally more benefits in terms of increased efficiency. Axial fans with blade modulation operate at a very efficient load profile; this type of fan configuration reduces the benefits associated with VFD operation. In 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 both the speed control and blade angle control.

In B&V's evaluation of the feasibility of implementing the VFD technology to the forced and induced draft fans at LVP, the cost of the technology was reduced to terms that EPA used to justify the associated cost of the technologies in the ACE Rule[2] from the Sargent & Lundy Report, which is dollars per kW. The projected cost for LVP to employ the VFD technology to the forced draft fans is $3.10 per kW. The projected cost to add VFD to the induced fans is $4.60 per kW, which makes the overall cost of adding the VFD technology to the existing fans $7.70 per kW. Adjusting the cost range from the Sargent & Lundy report to 2020 dollars for the VFD technology, the projected cost of the VFD technology is within EPA's reasonable expected cost range.

The potential HRI however is not within EPA's expected range[3]. B&V has estimated that this technology could improve heat rate for LVP by 0.06% at full load and 0.08% at low operating load conditions. This expected heat rate improvement is less than the low end of EPA's expected range of 0.2% for VFD technology.

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)[4]. 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.

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[2] RIA for Repeal of CPP, and the Emission Guidelines for Greenhouse Gas Emissions from Existing EGUs, Table 1-5, page 1-16.

[3] 40 CFR 60.5740a, Table 1 to Paragraph (a)(2)(i)—Most Impactful HRI Measures and Range of Their HRI Potential (%) by EGU Size.

[4] Federal Register, 84 FR 32520, September 6, 2019, page 32539.

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 upgrades for steam turbines

Upgrades or technology improvements, such as blade path upgrades to steam turbines are dependent on the original design of the specific turbine and OEM. There are other factors that owners/operators must consider before electing to embark on a blade path upgrade, including:

- Assure a sufficient generator size to handle the increased turbine power output.
- Confirm 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 Subpart UUUUa, this (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.

LVP's unit utilizes a Siemens SST-6000 steam turbine to harness the potential energy of the steam and transmits it to the generator. LVP's 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.

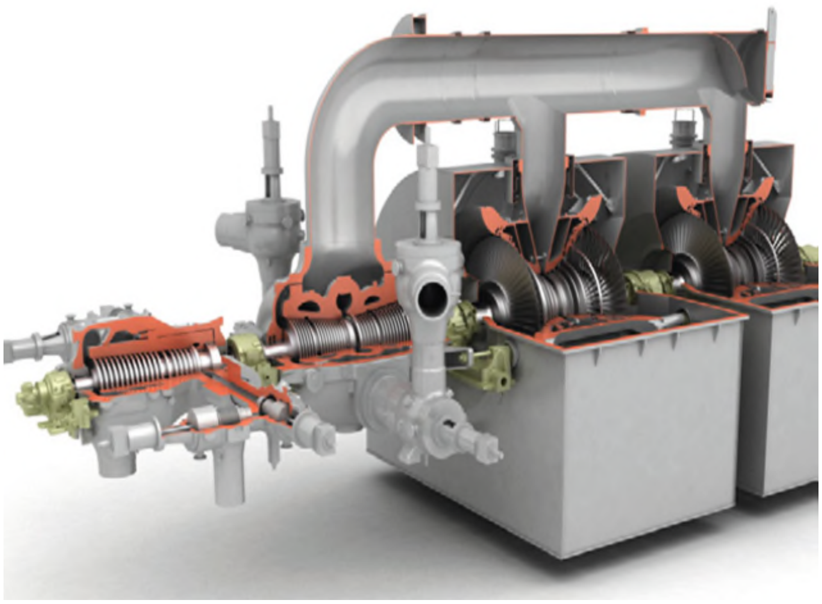

Figure 6. Cut-away of Siemens SST-6000 Steam Turbine

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

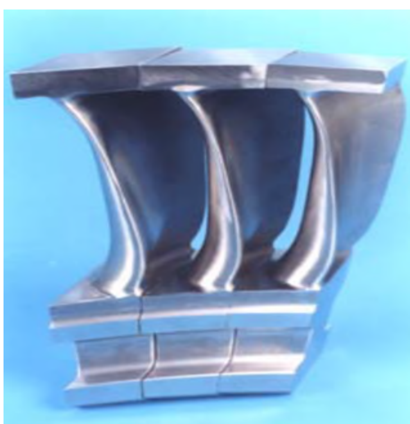

Figure 7. Photograph of the Turbine Blades

Siemen's advanced design with improved blade and sealing design for tighter clearances increases 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.

Siemens claims that the SST-6000 package has over a 48% efficiency. As of June 2015, there are 488 units of the SST-6000 package series operating worldwide. Currently, Siemens does not offer any blade path improvement 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/Replacement of the Economizer

Economizers are basically tubular heat transfer surfaces used to preheat boiler feedwater before it enters the furnace pass or wall tubes for "once through" units. The economizer is a heat exchanger(s) 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 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.

LVP's economizer 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 likelihood of erosion and trapping of ash on the tube surfaces.

LVP's unit utilizes a 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 affects the performance of the SCR. Typically, SCRs need an inlet exhaust temperature of 630 to 680 degrees Fahrenheit (^oF) to initiate the reaction required to operate the SCR. At full load conditions, LVP has to maintain a minimum inlet exhaust temperature for the reaction to occur in the SCR of 670^oF. To optimize the NO_x reduction reaction in the SCR, LVP attempts to maintain the flue gas temperature at 680^oF. To maintain this minimum flue gas temperature, LVP utilizes a by-pass duct around the economizer, which allows a portion of the hot flue exhaust gases to be routed around the economizer before entering the SCR.

Other factors that must be considered when evaluating redesign and replacement changes are the acid gas dew point and velocities of the flue gas. Excessive corrosion in the ductwork, pollution control devices, induced 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 units, 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 redesign and replacement. This design criteria needs to be carefully considered. LVP typically burns a high ash coal.

In the application, LVP claims their original design and constructed economizer is sized correctly for their 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.

The writer agrees with the applicant that a redesigned economizer would not offer any HRI without affecting the unit's ability to control NO_x emissions. Should LVP consider redesigning the economizer, LVP's redesign would need to evaluate whether the proposed upgrade would affect the performance of the SCR and would this performance change trigger major modification of major source permitting requirements under the New Source Review Program of the Clean Air Act.

Improved Operating and Maintenance (O&M) Practices

Improved Operating and Maintenance Practices are not clearly defined in Subpart UUUUa. LVP has identified several practices and programs that they employ to either maintain or improve their unit's heat rate.

The following list of measures, programs, and other notable improvements that LVP employs 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
    - Internal and third-party evaluation of the monitored heat rate
    - Real time performance modeling (ASME-based on Performance Test Code)
- Condition assessments of equipment with appropriate maintenance/operational response to insure operating in normal expected bands of equipment performance
    - Pumps stay on pump curves
    - Fans stay on fan curves
    - Heat exchangers' and condensers' performance
- Maintenance and reliability practices
    - Proactive maintenance practices
    - Pulverizer maintenance and performance program
    - Annual critical valve leak study
    - Annual and ongoing tuning of the control systems
    - Computerized Manager Maintenance System to manage workflow of relevant O&M resources
- Training
    - All personnel are trained on Heat Rate Fundamentals
    - Operations, Maintenance, Reliability Sections have attended Heat Rate and Combustion Fundamentals

- Reliability and Performance Sections have received additional ongoing training to include General Physics “Fundamentals on Power Plant Performance”

- Peer group review and continuous learning and improvement

HRI is an ongoing challenge. Further, determining the degree of the improvement is at times almost as challenging as implementing the improvement.

After resolving the unit’s original design issues in 2015, LVP’s reliability programs have significantly improved the unit performance which is shown in the following chart.

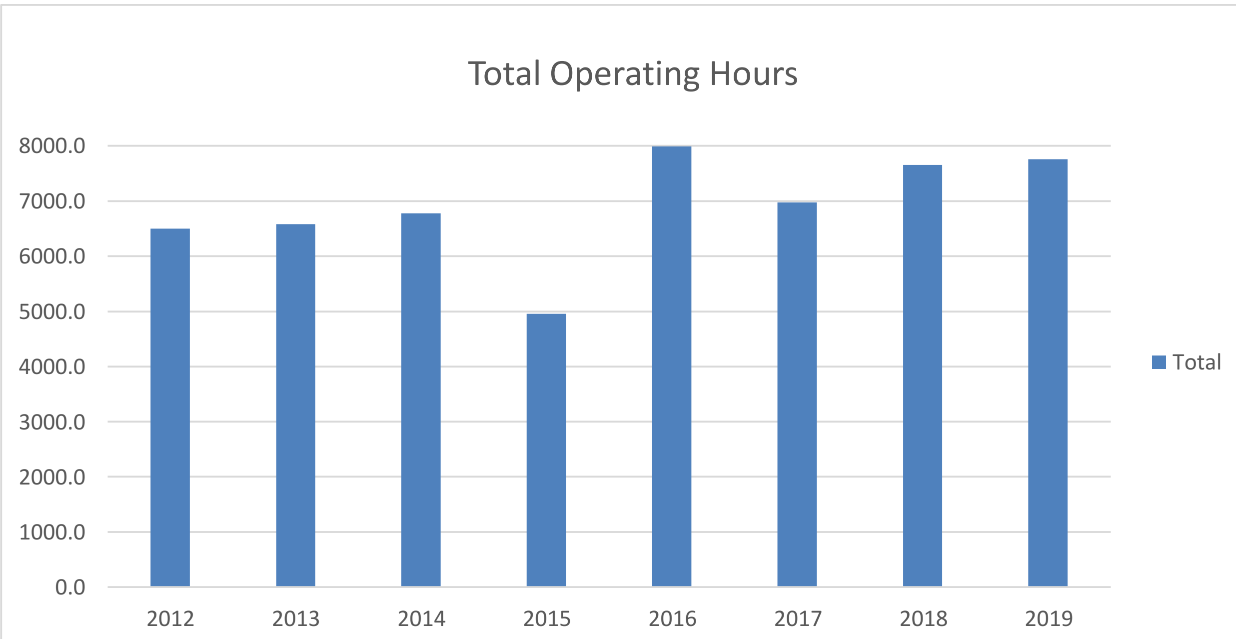

Figure 8. LVP Total Operating Hours[5]

In 2014, LVP began using B&V’s On-line Performance Monitoring System (OPM). OPM determines the net heat rate on an hourly basis using real time operational data. As part of this permit application, LVP provided the DAQ a copy of this data from 2014 through second Quarter of 2020. The following figure shows LVP’s efforts to continually improve the unit’s heat rate.

[5] Data submitted by LVP, July 24, 2020, LVP ACE Rule Data 2012 through 2020 Q2 - 2020-07-24 BH.xlsx

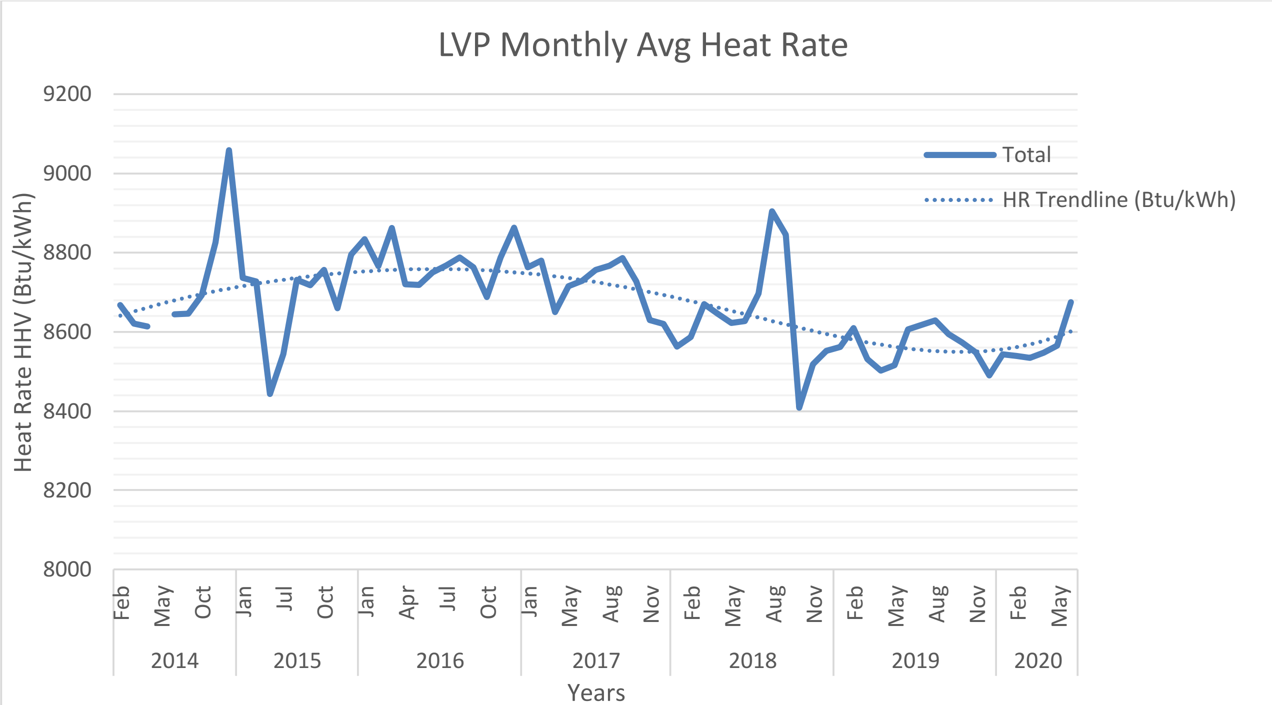

Figure 9. LVP Monthly Avg Heat Rate[6]

LVP's net plant heat rate (NPHR) is 8,800 Btu/kWh on a lower heating value (LHV) basis. EPA determined that the most efficient units are units with a NPHR of less than 9,773 Btu/kWh.[7] The most advanced coal-fired EGU in the nation is AEP's Turk Plant which is an ultra-supercritical steam generating unit with a nominal capacity of 650 MW with a NPHR of 8,730 Btu/kWh.

LVP cannot quantify the actual improvement in their HR to these listed O&M improvement values. This OPM HR data clearly suggests that these efforts, on a collective basis, are improving the unit HR. Over time, key components or equipment will wear down over time. As result of the wear and tear of components such a pumps and turbine blades, the NPHR of a unit will increase which is referred to as unit degradation. LVP expects that the trend line in Figure 9 to continue to climb with period of decreases when these key components are repair, which LVP plan to conduct once every five year of minor repair outages and major turbine repair work to be conducted once every ten years. These minor and major maintenance outages it to minimize this unit degradation as much as possible.

Several of the O&M measures that LVP has implemented monitors the preformed of the critical components which allows LVP to properly allocate resources and martials for the minor and major repair outages in effort to regain the unit efficiency (heat rate).

[6] Data submitted by LVP, June 26, 2020, LVP Generation and OPM Heat Rates 2020-06-26.xlsx

[7] RIA for Repeal of CPP, and the Emission Guidelines for Greenhouse Gas Emissions from Existing EGUs, Table 3-1, page 3-6.

LVP has noted many programs, activities, and training as HRI under the O&M category. Being trained, adding an improvement program, or redesigning a piece of equipment to the latest technology does not always improve the heat rate of any unit.

LVP has adopted all of the measures that EPA noted in the ACE Rule, which include HRI training for O&M staff, perform on-site appraisals to identify areas for improved heat rate performance, and improved steam surface condenser cleaning. The writer believes there is no additional HRI for the O&M technology category that can be employed.

CONCLUSIONS of the HRI Evaluations

LVP concluded, after evaluating these seven HRI technologies, that their unit has no potential benefit (reducing the unit's heat rate) from any of these technologies as listed in Subpart UUUUa of Part 60. EPA did anticipate that the most efficient units would have little to no potential heat rate improvement when applying the BSERs.[8] The writer concurs with this assessment.

ESTABLISHING THE STANDARDS OF PERFORMANCE

LVP claims all the HRI that are identified in Subpart UUUUa have been implemented or installed (intelligent sootblowing) before 2016. LVP has proposed a baseline from 2016 through second Quarter of 2020 for establishing a CO_2 emission standard . The CO_2 emissions data was collected from a 40 CFR Part 75 certified continuous emission monitoring system (CEMS) without the bias factors being applied (unbiased Part 75 CO_2 Data). LVP CO_2 monitor had an overall monitor uptime of 99.53%. Only 0.47% of the baseline data contains CO_2 rates using Part 75 Substitution Procedures. At this high level of monitor available, the Part 75 Missing Data Procedures would only require LVP take the average of the hour before and the hour after the period of the missing CO_2 readings.[9] In the baseline, only 169 hours contain substituted data out of 35,937 operating hours. Thus, there is no concern for the baseline contain substituted data for CO2 emissions.

Initially, LVP proposed a single standard based on an average of hourly CO_2 emissions rates when the unit was operating above its minimum load, which is 40% or 313 megawatts (MW) gross basis from the baseline data. To account for variability in the unit, LVP proposed the use of three standard deviations to the average of the CO_2 emissions over the entire baseline period. This approach specifically excluded CO_2 emissions during startup and shutdown events. Additionally, EPA disallows work practices to be utilized when establishing the standards in the emission guidelines of Subpart UUUUa. Also, the proposed standard (average of the baseline emission rate plus three times for the standard deviation) could not be justified as a constrained standard.

This approach of using a single standard does not account for changes in the operating mode of the unit. Currently, the LVP's unit is a base loaded, which allows the unit to be operated at its optimum heat rate (most efficient). The regional transmission organization (RTO) that this unit

[8] RIA for Repeal of CPP, and the Emission Guidelines for Greenhouse Gas Emissions from Existing EGUs, Pages 1-12, 1-17.
[9] 40 CFR 75.31(b)(1)

provides electricity for is a very competitive market that routinely varies demand from its supply resources. At some point, this unit's operating mode may shift from base load to load following (Cycling). The RTO dictates the loading of the unit based on actual supply and demand of the RTO's electric grid. Thus, the unit may or may not be operating at its optimum load to achieve its optimum unit heat rate.

Looking at the CO_2 data from the unit, there is a significant amount of variability in the unit's hourly CO_2 emissions data. Instead of looking at an overall average or median of the hourly CO_2 rate from the baseline period, the data was reduced into months then evaluated. These approaches, by themselves, did not effectively minimize the peaks (smooth) in the CO_2 emission rate data over the entire baseline period.

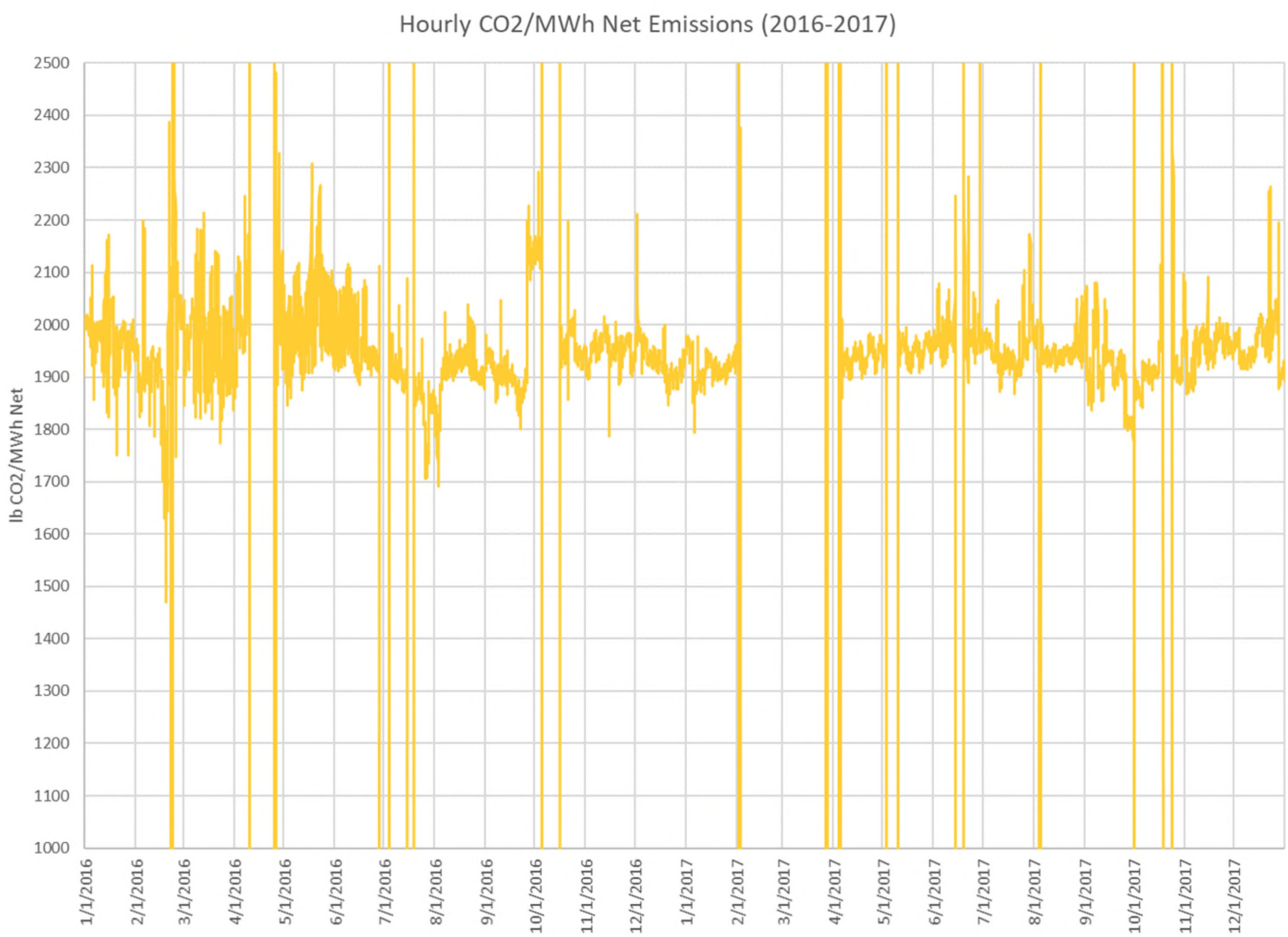

Figure 10. Hourly CO_2/MWh Net Emissions (2016-2017)[10]

[10] Data submitted by LVP, July 24, 2020, LVP ACE Rule Data 2012 through 2020 Q2 - 2020-07-24 BH.xlsx

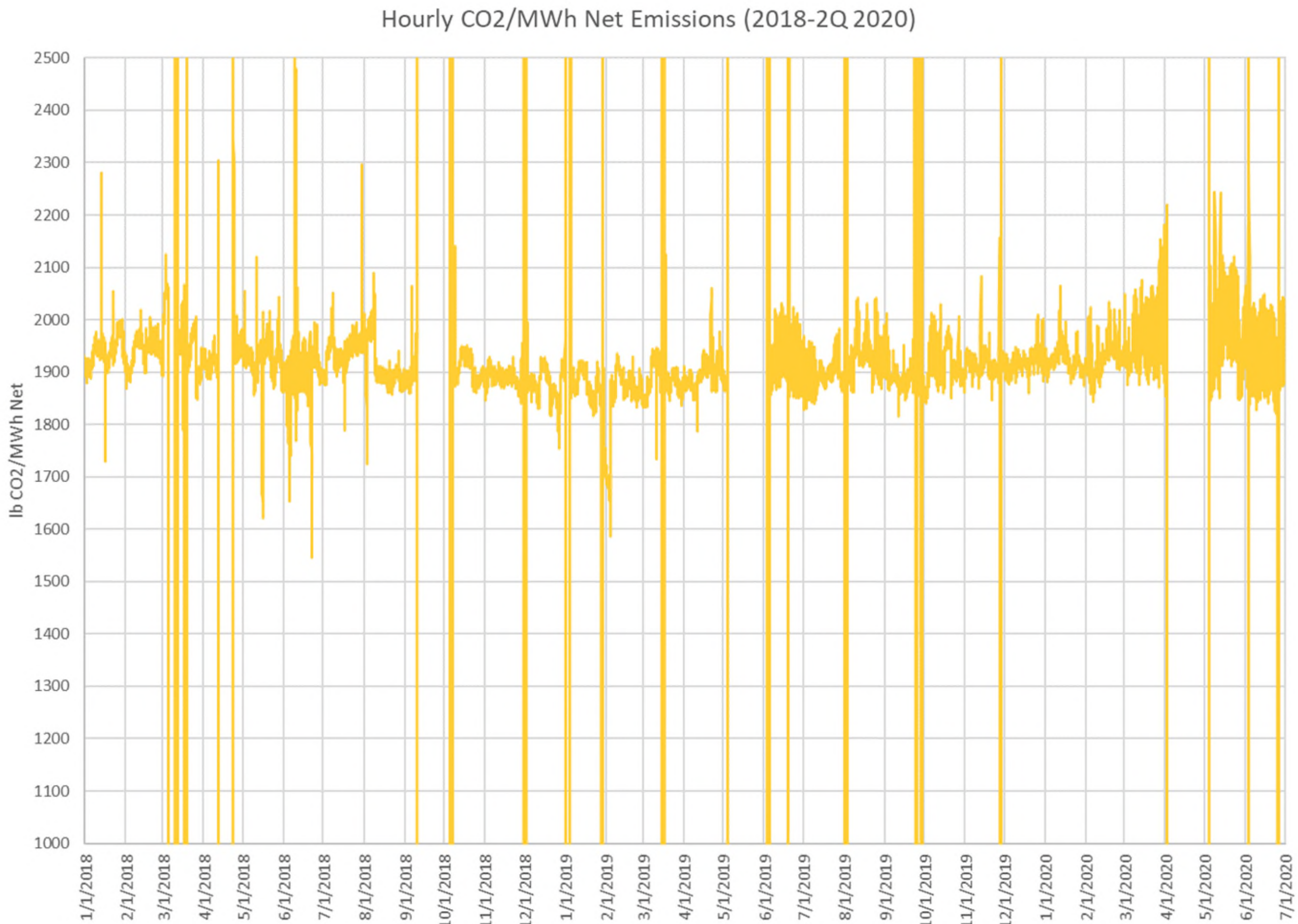

Figure 11. Hourly CO_2/MWh Net Emissions (2018-2Qt 2020)[11]

Adopting a load bin concept is one of the methods for developing a standard discussed by EPA in its response to comments on the ACE[12] and suggested in the "Guidance on Implementing the Affordable Clean Energy Rule: Engineering, Operations and Compliance Considerations" prepared by B&V for the National Rural Electric Cooperative Association. [13] This approach allows the standard to account for efficiency changes of the unit with respect to the different operating loads. Also, this approach allows the unit operator the flexibility to change the operating mode of the unit (base load, load following, peaking unit) without the need to modify the standard.

The data for the baseline period was divided into six bins which consists of one bin for startup and shutdown operations (the load at or less than stable load conditions) and five for normal operational load bins. The startup and shutdown bin, referred to as Load Bin 0 (LB-0), is defined as when the unit is operating up to and including the minimum stable load, which is 40% of the

[11] Data submitted by LVP, July 24, 2020, LVP ACE Rule Data 2012 through 2020 Q2 - 2020-07-24 BH.xlsx
[12] EPA Response to Comments (RTC), Section 3.1 (Response to Comment No. 2).
[13] https://www.cooperative.com/programs-services/government-relations/Documents/GuidanceonImplementingtheAffordableCleanEnergyRule.pdf

maximum load (313 MWh gross). The current 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 the following table.

Table 3 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 evaluated to ensure there was an adequate number of data points in each of these bins to develop a standard. The following table breaks down the operating hours, by bin, across the baseline period.

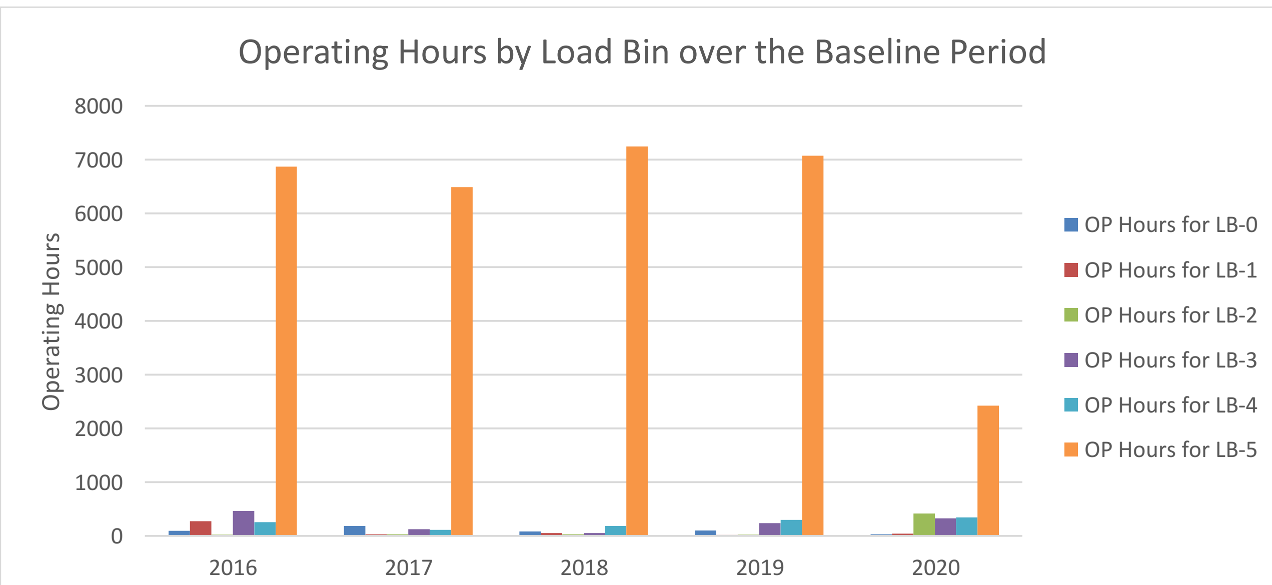

Figure 12. Operating Hours by Load Bin over the Baseline Period[14]

The above figure clearly demonstrates that Load Bin 5 has enough data in any given year. However, this case cannot be made for any of the other load bins. Thus, the entire baseline period was used for developing the standards for all of the bins.

[14] Data submitted by LVP, July 24, 2020, LVP ACE Rule Data 2012 through 2020 Q2 - 2020-07-24 BH.xlsx

The above figure clearly demonstrates that Load Bin 5 has enough data in any given year. However, this case cannot be made for any of the other load bins. Thus, the entire baseline period was used for developing the standards for all of the bins.

The nature of the actual operation and purpose of the startup and shutdown operations will not allow the peaks and valley in the CO_2 emissions data to be minimized (smoothed) out into any reasonable levels. During the startup phase, plant operators, relying on a tightly prescribed control system logic, must safely and quickly get the units up to the minimum operating load. 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. Thus, the CO_2 emission rate is a declining curve and the CO_2 rate cannot fall within a normal distribute curve. be . During the startup phase, these EGU's will have a negative heat rate for a certain period until the unit begins to generator electric. When examining the data closely, one realizes there are several hours during startups when there are CO_2 emissions while no electricity is being generated. To avoid a division by zero error by determine the hourly CO_2 rate and ensure all of the CO_2 emissions during the startup and shutdown phase are counted, the sum of the hourly CO_2 mass emission rates and sum electricity generation were aggregated into monthly totals throughout the baseline period. These monthly totals of CO2 mass emissions and electricity generated were then used to determine the CO2 rate of the unit for the corresponding month. This same approach was used for each of the load bin as well.

None of the HRIs identified by Subpart UUUUa would improve the unit's heat rate during startup and shutdown operations. The most feasible option for reducing CO_2 emissions during this phase is to use a lower carbon content fuel to preheat the unit as much as possible. LVP does this by burning natural gas during startup operations. Their CO_2 baseline emissions data is representative of this activity.

STASTICAL DATA ANALYSIS

The average of the monthly data converted, in 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 the following table.

Table #4 Summary of Monthly Average of the Normal Operations Load Bins[15]

Load Bin	Average (lb/MWh gross)	Standard Deviation (lb/MWh gross)	Kurtosis	Skewness
LB-1	2,184	146	9.60	2.40
LB-2	2,053	80	0.45	-0.71
LB-3	2,004	66	10.56	-2.52
LB-4	1,968	40	-0.02	-0.11
LB-5	1,917	31	-1.01	-0.02

[15]Data submitted by LVP that was processed by the DAQ, July 24, 2020, LVP ACE Rule Data 2012 through 2020 Q2 - 2020-07-24 BH.xlsx

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 peeking curve and values less than -1 indicate the curve is flattening. The skewness for data with a normal distribution is zero. Load Bins 2, 4 and 5 are approaching a normal distribution curve. Considering the low number of operating hours for Load Bins 1 and 3, these results were expected. For Load Bin 2 the results were not expected

The next level of smoothing the baseline data was to take the monthly rates and determine a twelve-(12) month rolling (moving) average for each of the operating bins. 18-month rolling averages of the monthly data were also determined. Another approach, which was suggested by EPA[16] as a means to smooth the data out, was taking the sum of the mass CO_2 over a 12 month period divided by the sum of the electricity generated (sum of the CO_2 divided by the sum of the generation).

All these approaches smoothed the data out. The 18-month rolling average did the best across all the load bins, which was expected. For LB-5, all the methods yield near the same results. LVP believes that the 12-month rolling approach is the best. Second, LVP proposes that taking the average and adding two times the standard deviation (SD) would be a reasonable means for establishing a standard.

The following justifies this statistical approach and proposed means for establishing a standard.

When assessing the LVP CO_2 data, several areas become readily apparent and affect the appropriate methods for calculating the CO_2 Standard of Performance. SD (the measure of the "spread" of a data set around its mean value) 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. To further explain:

1) The unit has spent most of its runtime (>92% from 2016 through 2020) in Bin 5 at generation loads greater than 689 MWG (Gross). The data in Bin 5 is of high quality with many samples held tightly around the mean, thereby very accurately reflecting the units CO_2 performance in that 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). In Bin 5 this SD 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 load. Statistically speaking, 95% of the data will fall within 2 standard deviations of the mean.

2) For Bins 1-4, 313 MWG through 689 MWG, a challenge presents itself, since they account for less than 7% of the unit's run hours. There is a significant lack of data points, and the

[16] Greg Honda, Email Re: LVP_Data_Model_2016-2020_2nd_Qtr_EPA.xlsx, July 23, 2020.

unit is generally moving load as quickly as possible to achieve maximum gross generation which is reflected by Bin 5. Based on this situation, the average is of a lesser certainty calculation than what was seen in Bin 5 and demonstrates a higher variability due to transient generation load as well as a lower number of data points. This results in a higher standard of deviation in each of these load bins than in Bin 5. However, due to the significance of standard deviation, the idea of the mean + 2 SD is still relevant and applicable. The data in these bins is less evident, and the Bin Standard calculations (Mean + 2 SD) still give reliable and meaningful results as 95% of the data still fit within this standard.

3) The LVP has demonstrated, in an appropriate manner, that all BSER or equivalent technologies have been implemented, and both heat rate and CO_2 performance is currently meeting the requirements set forth under the ACE Rule. Based on these demonstrations, no further improvements are required or anticipated for either heat rate or CO_2 rate.

Based on both the Bin 5, and the Bin 1-4 discussion, the concept of Sample Standard Deviation is both valuable, and appropriate, in predicting future unit performance based on the sample data from 2016 through second quarter 2020 . Additionally, since the unit has demonstrated implementation of all BSER (or equivalent), no performance enhancement is required or anticipated. This standard deviation accounts for normal operational variances and measurement uncertainty. Measurement uncertainty alone can have a much larger acceptable variation than 2 SD in current data. Therefore, the 2 SD approach is appropriate to set standards that can be met via current unit operation, and that is indeed the case for Bins 1-5 utilizing this method of analysis and calculation.

For consistency purposes, Load Bin 0 was developed using the same 12-month rolling average approach and establishing the standard by taking the average of the twelve12-month rolling plus two times the standard deviation.

Instead of having six different bin standards to comply with throughout a compliance period, LVP proposes a weighted approach for Bins 1 through 5 and compliance with Bin 0 separately. Weighted average standards are not a new concept under the Clean Air Act (i.e. NO_x standards for different fuels under Subparts Da and Db of Part 60[17][18]) or West Virginia's Air Pollution Control Act (i.e. 45 CSR 7, 45 CSR 21[19]). The weighing mechanism needs to be common for the bin standards and measurable. LVP proposes using operating hours of the unit within each bin. The following is the equation used to determine the weighted average standard for Level 1 (normal operations).

$$Level\ 1\ CO_2 weighted\ Avg = \frac{\sum OPHL1_{LB-1} \times CO2_{LB-1} + \sum OPHL1_{LB-2} \times CO2_{LB-2} + \sum OPHL1_{LB-3} \times CO2_{LB-3} + \sum OPHL1_{LB-4} \times CO2_{LB-4} + \sum OPHL1_{LB-5} \times CO2_{LB-5}}{\sum OPHL1_{total}}$$

[17] 40 CFR 60.44Da(a)(2).
[18] 40 CFR 60.44b(b)
[19] 45 CSR 7-4.1, 45 CSR 21-4.1.a.4.

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).

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

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

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

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

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

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

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

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

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

$CO2_{LB-5}$ = 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)

There is no document or guidance that outlines exactly how any emissions data should be processed or developed in creating the standard. The guidelines state that the standard must be quantifiable, verifiable, permanent, and enforceable for each designated facility.[20] So, Subpart UUUUa does not specifically prohibit the use of bins or weighted average approaches in establishing a standard.

The standard also needs to be constraining and 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 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 BSERs, even the O&M improvements, could have any potential impact on reducing startup and shutdown emissions. The emissions of CO_2 that occur during startup/shutdown is almost insignificant when compared to the rest of the load bins.

[20] 40 CFR 60.5755a(b)

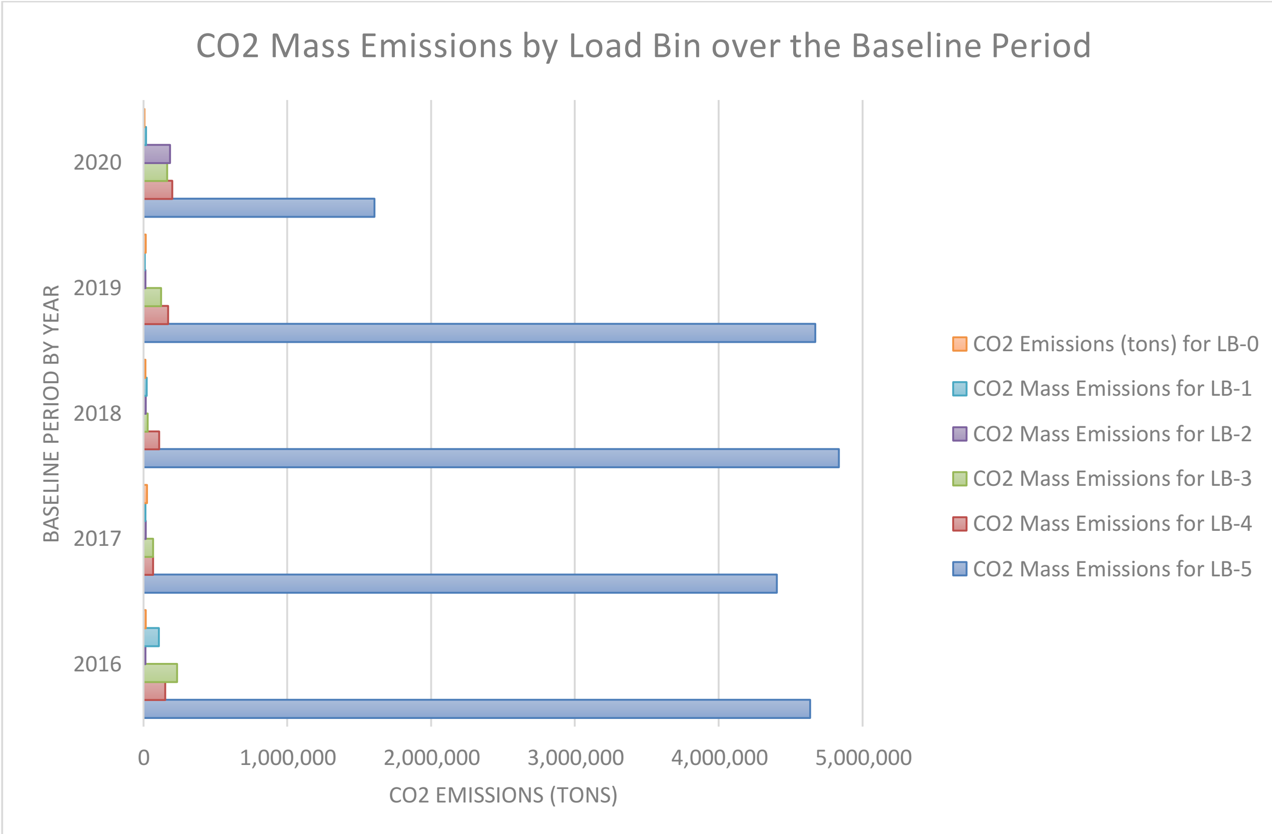

Figure 13. CO_2 Mass Emissions by Load Bin over the Baseline Period[21]

The emission rate for LB-0 is significantly higher because the unit is not generating electricity.[22] To ensure the weighted average standard is not influenced by Bin 0, Load Bin 0 will be a standalone standard.

LVP's unit has only been in operation for eight and a half years. There is not a great deal of emissions data that can be used for demonstrating that the standard is constraining or achievable. LVP proposes the compliance period be on a calendar year basis. Due to the lack of historical data, the annual actual emissions, which includes the data from the baseline period, and the corresponding proposed standard was determined and charted in the following graph.

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[21] Data submitted by LVP, July 24, 2020, LVP ACE Rule Data 2012 through 2020 Q2 - 2020-07-24 BH.xlsx
[22] Black & Veatch, Guidance on Implementing the Affordable Clean Energy Rule: Engineering, Operations and Compliance Considerations, 7 February 2020, Figure 3-16, Page 3-19

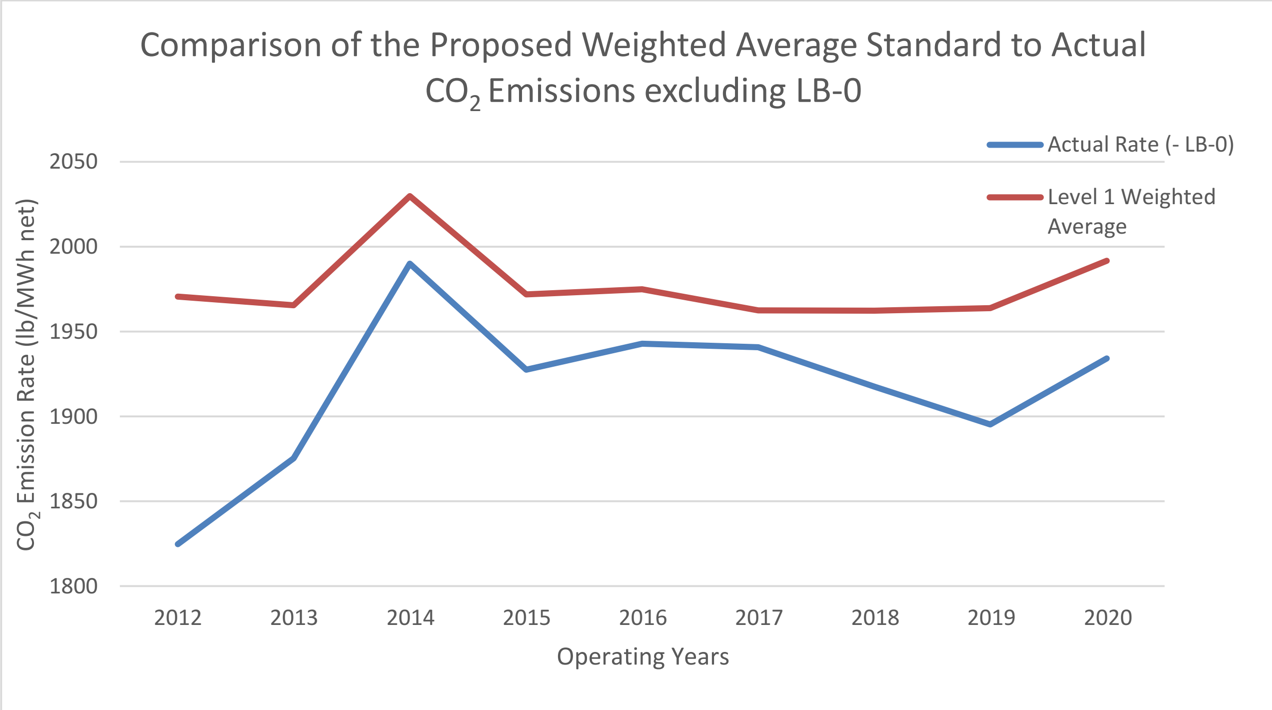


Figure 14. Comparison of the Proposed Weighted Average Standard to Actual CO_2 Emission Rate excluding LB-0[23]

The curves in the above figure excluded the CO_2 emissions when the unit is operated at or below the minimum load (313 MWh – gross). The margin of compliance is at the greatest in 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 margin of compliance occurred in 2012, which is 7.4%. The margin of compliance quickly decreased from 2012 to 2014 from 7.4% down to 1.9%.

From initial startup to 2015, the unit experienced original design and construction related defects that caused forced outages of the unit. These design and construction issues were corrected in the rehabilitation outage in 2015 which encompassed all the major components of the plant. After addressing these issues, the unit began improving its efficiency and the margin of compliance increased slightly. This margin decreased to 1% in 2017. In 2017, the facility switched its source of fuel (coal) to a better-quality fuel (less ash, higher heating value).

The weighted average standard curve levels out in 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 margin of compliance is beginning to decrease in 2020, which is mainly due to the unit operating at lower loads - its least efficient operating levels (Load Bins 3 and 4).

[23] Data submitted by LVP, July 24, 2020, LVP ACE Rule Data 2012 through 2020 Q2 - 2020-07-24 BH.xlsx

The average compliance margin over this period is just over 3%. Neither Subpart UUUUa nor the EPA states or suggests what would be an acceptable margin of compliance. The projected improvement of the unit's heat rate over the entire coal-fired fleet in the United States is 2% when fully implementing Subpart UUUUa. The average margin of compliance based on historical data is greater than this. However, this average margin is significantly less than the acceptable variability and accuracy of the CEMS.

One benchmark that is currently available to use as an indicator that the proposed standard is constraining and reasonably achievable is from Subpart TTTT - Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units. EPA did establish carbon dioxide standards for new and reconstructed EGUs under Subpart TTTT of 40 CFR 60. The standard for new EGUs is 1,400 lb per MWh on a gross generation basis. LVP's proposed weighted average CO_2 standard and actually CO_2 rate are significantly higher than this standard.

However, the standard for reconstructed EGUs is 1,800 lb per MWh on a gross generation basis. The compliance for the reconstruction CO_2 standard is set on a 12-month rolling basis on gross generation. This standard includes all times CO_2 emissions are emitted.

The following figure illustrates LVP monthly CO_2 emission rate on a gross generation basis from 2012 to 2nd Quarter 2020 with 12- and 36-month rolling averages of LVP CO2 emission rate. A gross basis was used to compare actual emission rates in the consistent terms of the NSPS reconstruction standard. LVP monthly rates in Figure 15 includes all CO2 emissions in the rate, which includes startup emissions that occurred in Load Bin 0 (LB-0). These actual emissions are compared to the NSPS reconstruction standard.

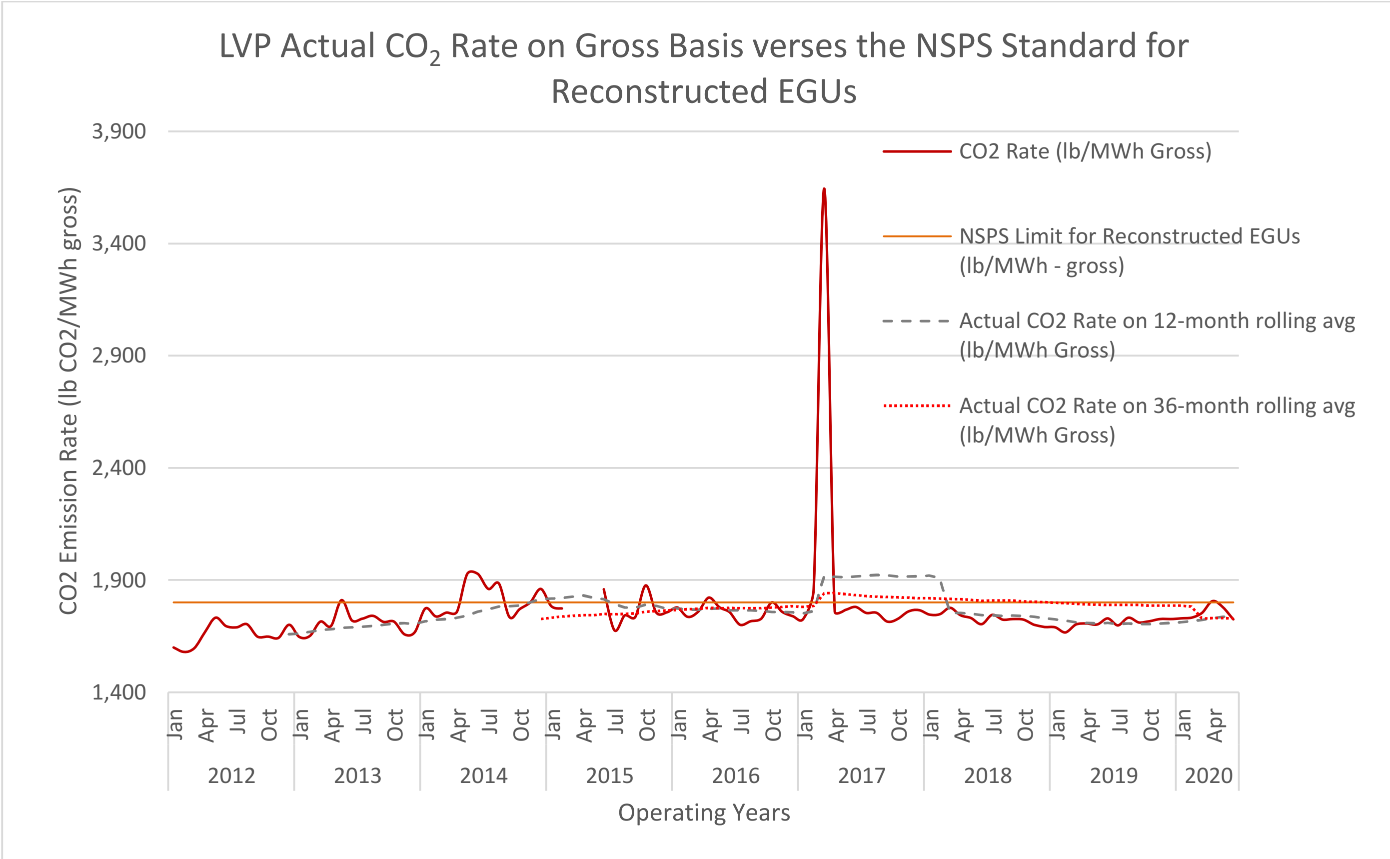


Figure 15. LVP Actual CO_2 Rate on Gross Basis verses the NSPS Standard for Reconstructed EGUs

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 15 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. 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.

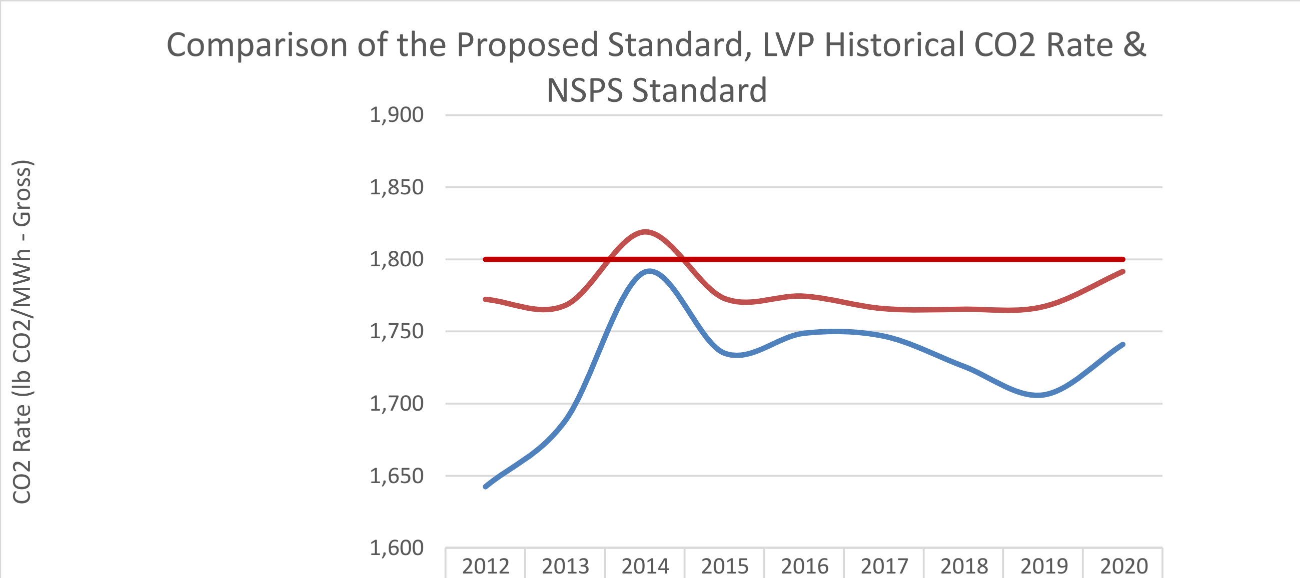
One cannot directly compare LVP's proposed standard with the reconstructed standard. However, the basic method (12-month rolling average plus two standard deviations) that LVP used could be recalculated on a gross generation basis.

Gross generation is the amount of electricity generated from by 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 generation is the actual amount of electricity sent to the electricity grid.

To compare LVP's proposed weighted average CO_2 standard with the New Source Performance Standards' (NSPS) reconstruction limit, LVP data was reprocessed on a gross basis in the same manner that was used to develop the standards for each of the Bins 1 through 5, which yield the following values from each of these bins.

Table #5 Bin Standards Adjusted to Gross Basis	
Load Bin	12 -Month Rolling Avg +2SD (lb CO2/MWh- gross)
LB-1	1929
LB-2	1897
LB-3	1845
LB-4	1802
LB-5	1762

Using these values for the corresponding bins, the weighted average CO_2 standard on a gross basis was determined for each operating year from 2012 through 2nd Quarter 2020 and plotted in the following figure.



	2012	2013	2014	2015	2016	2017	2018	2019	2020
Actual Rate minus LB-0	1,642	1,688	1,791	1,735	1,749	1,747	1,726	1,706	1,741
Proposed Weight Avg CO2 Level 1 Limit minus LB-0	1,772	1,768	1,819	1,773	1,774	1,766	1,765	1,767	1,791
NSPS Limit for Reconstructed EGUs (lb/MWh - gross)	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800

Figure 16. Comparison of the Proposed Standard, LVP Historical CO2 Rate & NSPS Standard

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 CO_2 rate is approaching the NSPS standard again. In 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.

LVP proposed a standard to be on a net generation basis, which is different than the NSPS standard which is on a gross generation basis. A standard on a net generation basis forces the unit operators to focus on minimizing the load consumed by the auxiliary equipment.

Startup/Shutdown Operations (SUSD) for the LVP unit make up less than 1% of the total operating hours in the 2016 – 2nd Quarter 2020 sample data set. LVP's unit operates in this region only for startups and shutdowns. The CO_2 Rate for this bin needs to be on a lbs/MWh gross basis, for most of the Bin 0 operations no power on a net basis is being generated. Although the Bin 0 emissions rates are much higher than in Bins 1-5, the time spent in Bin 0 is much lower, thereby resulting in a very small fraction of emissions being generated during SUSD operations.

Fundamentally, all factors incentivize minimizing operating time spent in Bin 0 as no revenue is being generated during operations in this Bin, only costs. Additionally, the unit has regimented control logic with set 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 Bin 0. The unit is moved to Bin 1 and above as fast as is operationally possible, limited only by design and/or operational challenges in safely ramping load and maintaining unit operational stability while moving out of Bin 0. Factors such as vibration, fuel feed, and other 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 Bin 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 Bin 0 as quickly as is safely possible.

LVP proposes the same compliance period for Load Bin 0 (LB-0) as well. There is a significant margin of compliance with the proposed standard when compared to actual startup and shutdown emissions on an annual basis. Typically, base loaded units like LVP are projected to startup and shutdown a few times. The potential for this margin of compliance to disappear is best illustrated in the following graph.

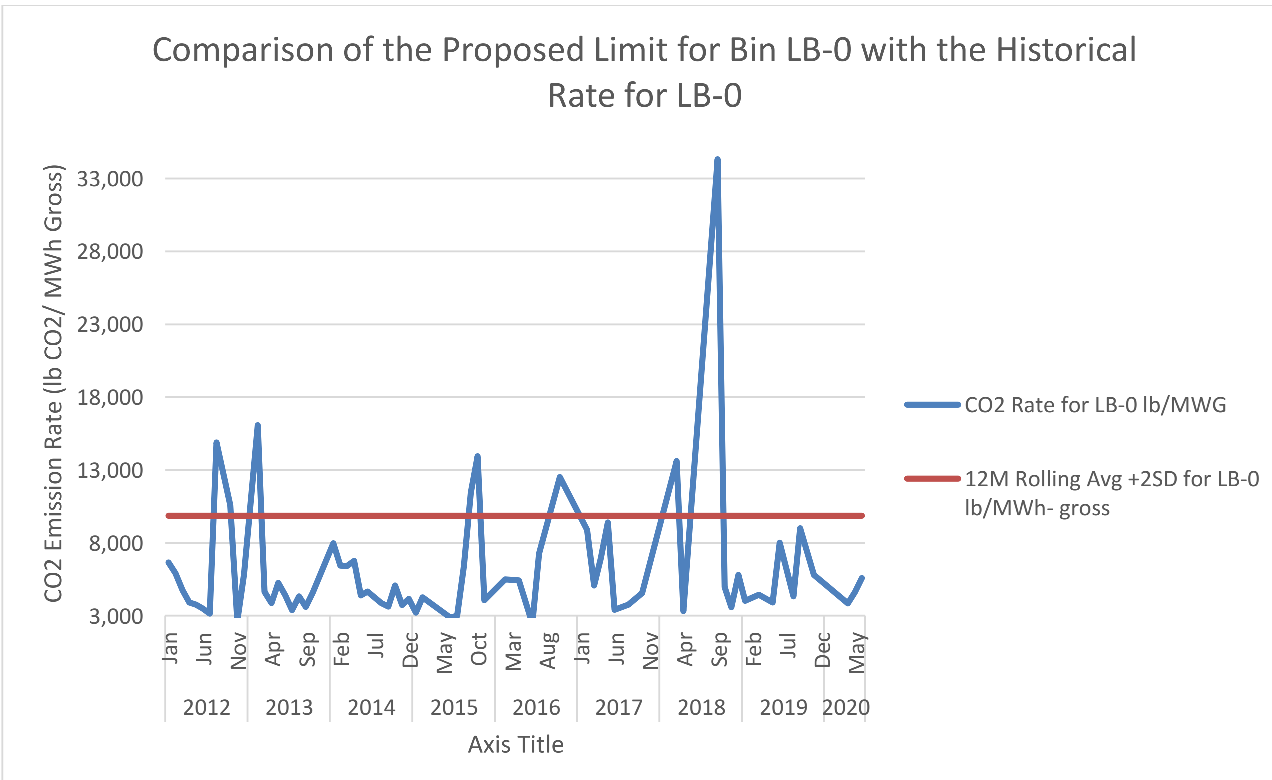


Figure 17a. Comparison of the Proposed Standard for Bin LB-0 with the Historical Rate for LB-0

Figure 17a above is the actual monthly CO_2 emissions that occurred when the unit was operating at or less than 313 MWh – gross basis. Averaging these emissions over a calendar basis, this graph shows the need for the standard to be averaged over a calendar -year basis.

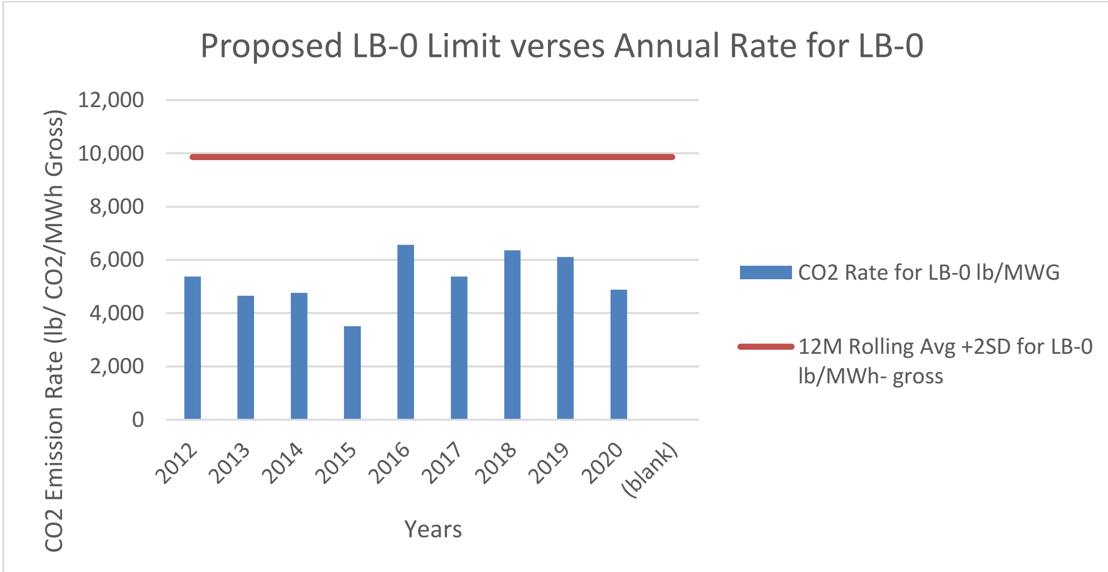


Figure 17b. Proposed LB-0 Limit versus Annual Rate for LB-0

Figure 17b above may illustrate that the proposed standard is not constraining. HRI in Subpart UUUUa or other improvements that LVP has made have had little to any effect on the unit's HR or CO_2 emissions during these startup and shutdown events (Operations in LB-0). Stretching the averaging period over a calendar year makes compliance achievable for the source. It should be noted that during this operating range, the unit's generator is being synced to the grid. Once this occurs, the load on the unit is quick increased just above its minimum load to be ready for PJM to dispatch the unit up to its desired load, which is the point that the unit is generating revenue for the operator (LVP). There is no benefit for LVP to operate in this load bin other than for startup or shutdown purposes.

Proposed Level 2 Standards

LVP is concerned that the proposed standard is too constraining to allow for high impact-low probability events that cause damage to the unit and have long lead times for materials to be made available causing the unit to operate at a significantly reduced efficiency.

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 and efficiency and economic viability of the generating unit. The impacts of these equipment failures can be reasonably categorized and estimated and are, therefore, ought to be contemplated in formulating Affordable Clean Energy rule requirements.

Overview

There are a significant number of scenarios where an unexpected equipment failure or condition monitoring finding may require a critical piece of equipment to be taken out of service that has significant impact to efficiency, ACE CO_2 compliance, and economic viability of the generating unit. To accommodate these scenarios, the idea of a Level 2 compliance standard was developed, which accounts for the failure scenarios and resulting efficiency losses listed below, as well as similar events. In the following document, several realistic scenarios which have occurred or may be reasonably expected to occur, have been presented and their anticipated effect on unit efficiency calculated. These scenarios are representative of a wide variety of failure mechanisms; however, they are not all-encompassing as there are many variations possible and it is not the intent of this demonstration to describe every failure scenario in detail.

Baseline Scenario –

This is the baseline unit operation and is used as a standard of comparison for the failure scenarios to estimate 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 minimal impact to the amount of net generation the unit could produce, but each of these scenarios would have a 7 – 10% impact to efficiency due to the increased backpressure on the turbine from the increased pressure in the condenser.

In the case of a circulating water pump failure, LVP has O&M strategies in place consistent with the BSER to largely mitigate this risk. Part of this 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 feels that even though the efficiency impact of such a failure is significant, it can be handled in a manner to get back to normal condition with appropriate speed to largely mitigate 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 the LP Turbine is the final stage of converting steam energy in 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 the forces placed upon 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 the blades.

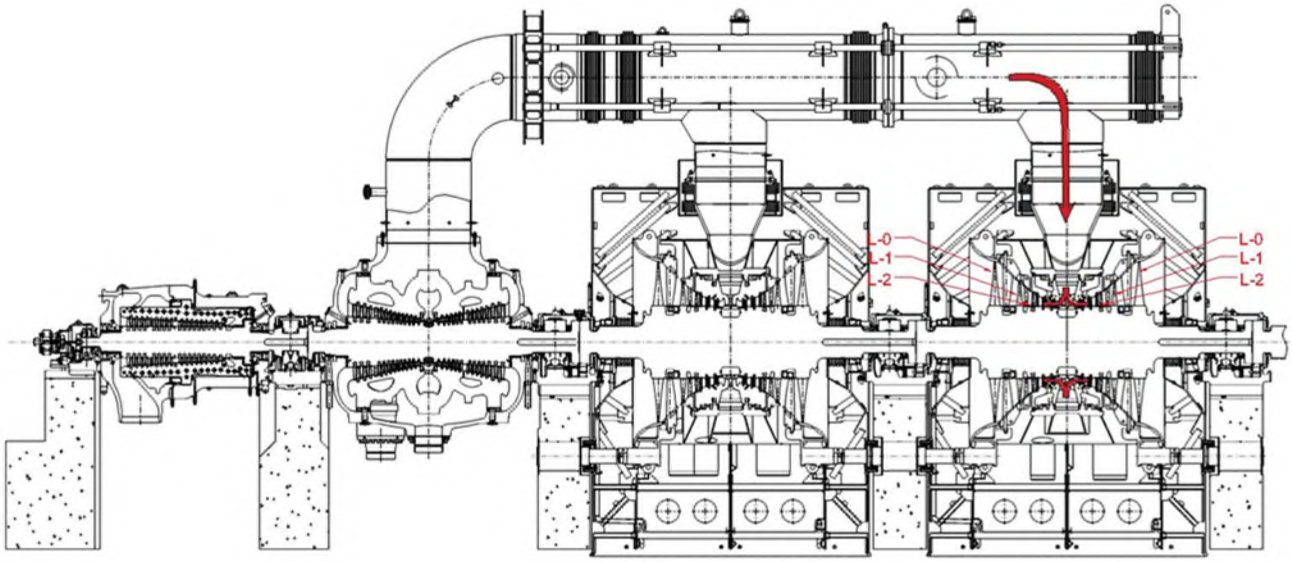


Figure 18. Longview Power Steam Turbine Overview

As you can see in Figure 18, the L-0 blading is the last row of blades and they are the largest blades in the system.

L-0 blading (the last rotating row) in LP turbines has been an ongoing industry-wide design and reliability issue for OEMs and plant engineers for many years. This row experiences a unique range of operating conditions that place significant stresses on the material. LVP, as well as most facilities, has an extensive advanced non-destructive examination (NDE) technologies program to monitor the condition of the blading. LVP utilizes an advanced phased array technique approximately every 25,000 hours of operation (approximately every 3½ years) or after a turbine trip with loss of condenser vacuum due to additional significant stresses on the LP turbine blading. This effort and expense are completed in hopes to identify an issue in a very early stage that can be corrected prior to a complete failure event, however, it is very feasible to find an indication that would require immediate action or mitigation.

In 2017, LVP 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 highly contemplated removing L-0 blading due to the damage on blades. If this had been required, it would have resulted in an approximate 15 - 30% MW load loss and a 14% impact to unit efficiency. The use of the Level 2 standards are a temporary measure that will allow continued operation and preservation of some revenue, thus maintaining the business until the parts can be supplied. Replacement of L-0 blades would require a 5-6 weeklong outage, in addition to the time required to manufacture the L-0 blades. This High Impact scenario would result in the unit operating out of compliance for well over a one-year period if not addressed through some reasonable permit relief mechanism.

Scenario 3 – 7/8 HP Heaters Out of Service

There are many cases where the unit 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 6 - Summary of Heat Rate Impacts

	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

Conclusion

In conclusion, there are equipment failures that can be reasonably managed via the O&M best practice BSER; however, there are real scenarios that even with world class O&M BSER practices, you can't reasonably mitigate the risk of CO_2 compliance issues. A relief method needs to be in place to support the ongoing operation of the facility under a scenario with this type of impact in order to maintain the economic viability of the unit through minimized downtime. Given the range of efficiency losses calculated from the various failure scenarios, the 110% Level 2 criteria are a realistic and accurate way to compensate, both operationally and economically, in the event these or similar failure events occur over the life of the unit, while still maintaining a high degree of environmental performance.

The DAQ agrees that these events are possible, do impact the unit's HR and interim fixes can allow the unit to continue to operate. Market conditions and the unit's degraded state will ultimately decide whether the unit will operate. It is the role of the DAQ to determine whether the source is or is not operating in compliance and what measures are adequate to bring the source back into compliance.

To address this Level 2 proposal, the DAQ views this as an alternative operating schedule to bring the unit back into compliance with the standard, like a compliance plan in a Compliance and Enforcement Order as a result of non-compliance. This concept is specifically outlined in the permit and puts the responsibility on LVP to develop this compliance plan in a timely manner to be allowed to operate at the proposed Level 2 standards. The permit takes a passive approached for Level 2 plans with a duration of six months or less from initial notification, through compliance plan completion. The DAQ acknowledges source owners/operators want assurance that their plan is acceptable, therefore, proposed compliance plans with start to finish durations of 6 months or less will be assumed to be approved unless the Director notifies the source in writing within 15 days of the plan submittal that it is not acceptable.

The permit takes an active approach for proposed Level 2 plans that have a projected duration from initial notification to completion of over six months. Long lead-time resources should be the driver for the need for this extended operation under the Level 2 standard. Thus, the permit will require the Director to formally approve or disapprove these plans within thirty days of submittal.

Again, like most compliance and enforcement driven compliance plans, the source is required to submit periodic progress reports on the status of the approved plan. The permit further requires the EGU operator to conduct a Root Cause Analysis to determine the cause of the failure and what additional measures should be taken to prevent a future failure from occurring or for minimizing the duration of the Level 2.

During periods when Level 2 in in effect, the standard for Load Bin 0 will not be adjusted. Equipment failures that affect the efficiency should not impair the CO_2 emission rate during Load Bin 0 operations.

A equation similar equation, like Equation 1, will be used to determine the weighted average while the unit is operating within Level 2 during the compliance period. See the following equations.

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 occurs 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. See the following equation as a example.

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)

Equations 1 through 3 will be in the permit under Condition 4.4.4.*Unit Degradation Adjustment Factor (UDAF)*

LVP completed 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 the analysis. Annual heat rate data was downloaded for all current operating supercritical coal-fired plants in the PJM Interconnection from 1994 to 2019 to provide a large sample size in the same geographic region as

LVP. This supercritical coal fleet is comparable to LVP with 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 19 below. 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.

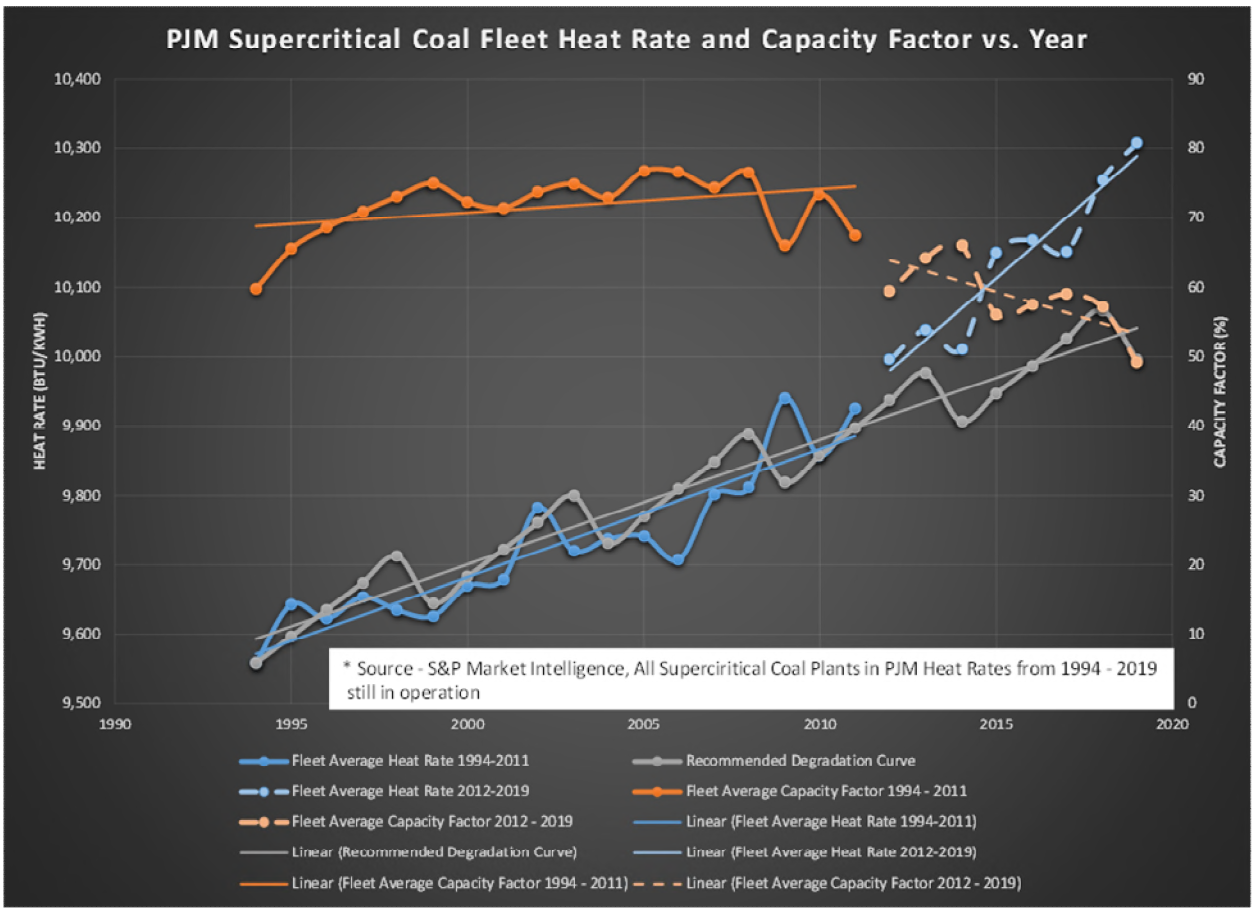


Figure 19. PJM Supercritical Coal Fleet Heat Rate and Capacity Factor versus Year

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 20 has the degradation displayed in terms of %/year and Cumulative % over a 25-year period based on fleet data starting in 1994 as year 0. As seen on the annual %/year over year trends you will see that 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.

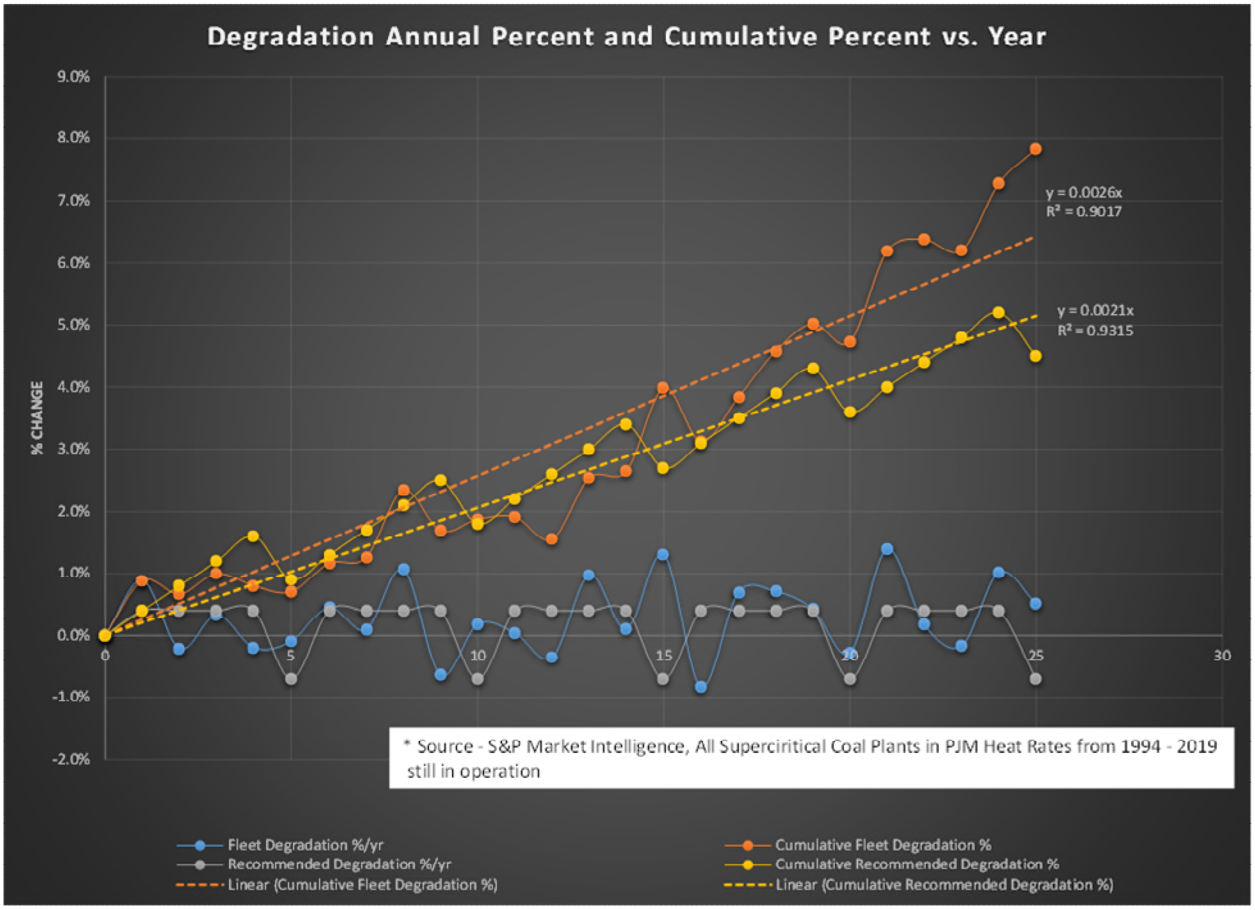


Figure 20. Degradation Annual Percent and Cumulative Percent vs. Year

LVP believes that the above discussion justifies their proposed UDAF of 0.4% annually with a five-year recovery rate of 0.7%.

Using the HR from the OPM, degradation of the unit is difficult to see. The unit's annual average HR performance is continuing to nearly improve each year from 2016 to the present. Except for Load Bin 2 (LB-2), the average heat rate by bin degraded from 2014 to 2015, which ranged 5.5% for LB-1 to 0.4% for LB-5. This degradation did occur despite LVP's efforts to address the design and construction issues that affect the unit's reliability. Lack of HR data from OPM and HRI in 2015 makes it difficult at best 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 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.[24]

EPA has proposed a revised carbon dioxide standard for combined cycle combustion turbines and EGUs.[25] 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.[26]

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.[27]

The projected Load Bin 5 standard is 2,089 lb CO2/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

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[24] Email from Una Nowling to Edward Andrews, September 25, 2020, Re: Help on ACE.
[25] 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.
[26] Federal Register 83 FR 65424, Page 65450
[27] Permit Application File R13-3495, June 26, 2020, LVP Generation and OPM Heat Rates 2020-06-26.xlxs

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.

Fuel Variability - Coal Adjustment Factor (CAF)

Thermal power plant operation costs are significantly dominated by fuel costs, which typically represent 70 to 80% of total cost of operations. Inherent in the fuel costs are the cost of fuel production, transportation, as well as operating costs associated with fuel handling, preparation, and combustion. Additionally, power plants are designed to consume fuels within a specific range of the various fuel characteristics and, thus, have standards as to what can be used. 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 costs becomes a key driver to the overall cost effectiveness of producing affordable and resilient electric power.

The concept of accounting for fuel characteristics specifics is a long-established process in the development of emission standards for power plants. Here, where EPA chooses to defer to the states to develop site-specific standards of performance in lieu of developing national subcategories as part of its BSER determination, it is essential that EPA allow states great latitude to account for the real-world fuel supply variability that might come into play at a given site. It is equally important that EPA recognize that few, if any, power plants will have the luxury of knowing they will need to switch fuel supplies 18-24 months in advance (which is the approximate time it would take to get an ACE State Plan revision proposed, finalized, and approved by EPA). Given these two fundamentals, LVP and the DAQ explored options for a coal adjustment factor that could be hard-wired into LVP's permit.

Appendix G of Part contain procedures for determining CO_2 mass emissions from coal fired EGUs. . These procedures 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 a unit compliance on a net generation-based standard. There are third party software programs that predict the unit 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.

Subpart UUUUa requires this standard to be on an energy output basis. For the standard, LVP elected to use a net generation basis, which means the standard takes into consideration the auxiliary load of the unit.

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 suggested approach, LVP proposed using an 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 enough data to be processed in meaning fashion 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 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 only adjust the standard based on the effect of the coal (fuel) quality with respect to the unit. LVP proposed having an independent third-party organization to oversee the testing, tuning of the unit on the new fuel source, and development of the ratio.

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 needs to be established. 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 the figure below, the margin is consistent except during the unit's initial startup.

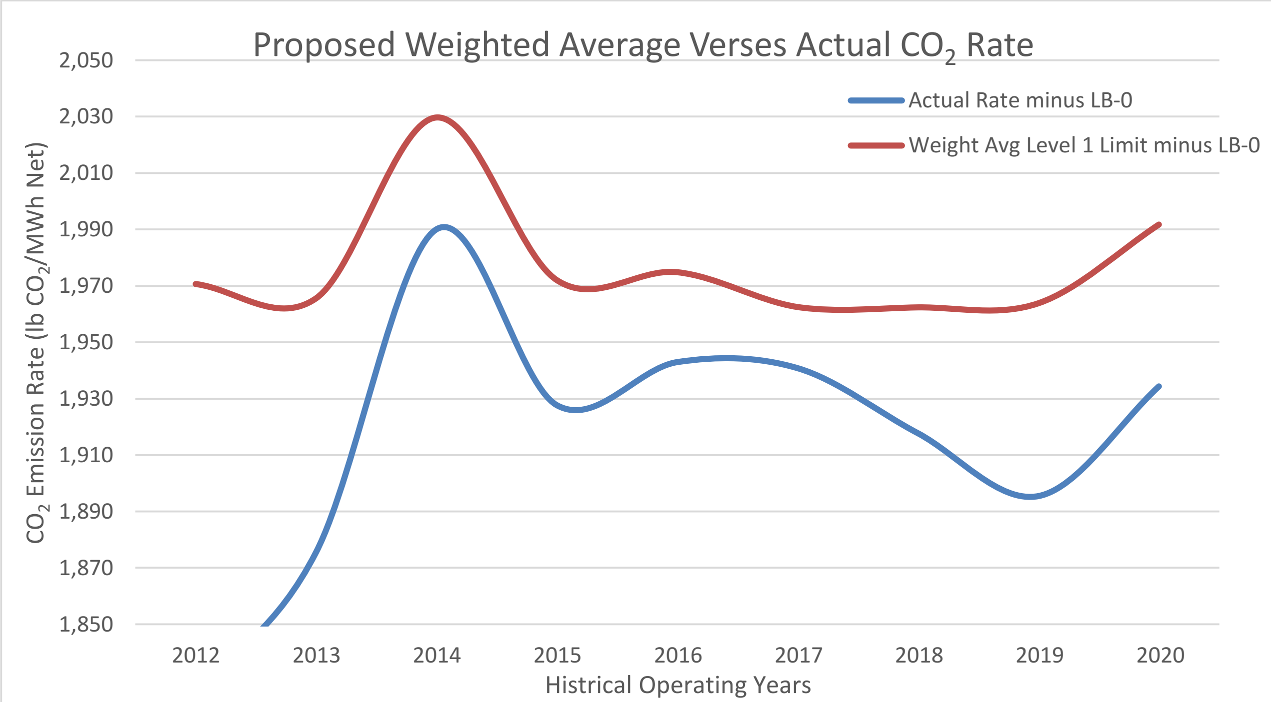

Figure 21. Proposed Weighted Average Versus Actual CO_2 Rate

The annual average margin of compliance is 3.06% over this period. This cap would indirectly limit the CAF to a reasonable margin back to 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 CO2 standard. The CAF or the cap does not prevent the applicant from requesting a new standard of performance (new CO_2 standard), which requires an update or modification to this permit and revised State Plan to be approved by the EPA Administrator.

If the CAF was only applied if the new fuel source increases 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, the permit stipulates that each test run must have at least 151 operating hours in Load Bin 5, which equates to 90% of the possible hours in a week. The collected data for each test run needs to yield a for one standard deviation of no higher than 68 lb CO2/MWh net.

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.

The CO_2 emissions data over the baseline was sorted for CO_2 emissions that occurred when the unit was operating within the gross load range of Load Bin 5. This data was reduced into a seven-day period (weekly) and sorted for weeks that contained 151 hours of data (90% operating time within Load Bin 5). The average of the standard deviation was 13.2 with the highest reading of 68.8. If LVP keeps their current O&M practices, the baseline testing data should fall within the average standard deviation. The new source test data will be dependent on the consistency of the coal that is supplied and tuning of the unit in a relative short period. Thus, the data quality requirement for the permit will be set based on the highest standard deviation recorded.

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 avg and Level 2 CO_2 weighted avg for the before the CAF and after the CAF using Equations 1 and 2 and the appropriate CO_2 limits for each of the load bins. The permittee shall use the following equation to determine the CO_2 weighted avg in lieu of Equation 3. The follow is Equation which will also be in Condition 4.4.4. of the permit.

Equation 4

$$CO2\ Weighted\ Avg\ =$$

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

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.

$\sum OPHL2_{BCAF}$ = 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.

$\sum OPHL1_{ACAF}$ = 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.

Compliance Period

LVP proposes the compliance period to be on a calendar year basis. Given the number of moving parts of the proposed "standards of performance", the compliance period needs to be simplified. If compliance with this standard is on a rolling average basis, then the UDAF would have to be applied monthly verses once per year. This raises the question, when is the recovery factor applied?

In the preamble to the final ACE Rule, EPA recognized that States have the flexibility to establish annual compliance by demonstration of fully operational and maintained HRI candidate technologies to be a method to demonstration compliance between the annual compliance dates.[28] The standards of performance LVP has proposed establish levels of performance for all phases of operation of the designated unit (start-up, shutdown, and normal operations) with appropriate monitoring to quantify the carbon dioxide emissions during these operations.

The source is subject to interstate emissions trading regulations (i.e. Acid Rain Program, CSAPR) that requires emission sources to have allowances for their annual emissions of sulfur dioxide and nitrogen oxides at the end of each calendar year as part of demonstrating compliance with the respective programs.

At this time, the EPA has not indicated they are going to update the data reporting format for the Clean Air Markets Division (CAMD) to allow for the reporting of net generation and emission rate of carbon dioxide emissions on an energy output basis. Thus, it will be up to the DAQ and LVP to collect, handle, process, and maintain the compliance data for the proposed standard. Therefore, the writer recommends that the compliance period for the standards of performance be set up on an annual calendar year basis as proposed with demonstration of fully operational and maintained candidate HRI technologies to be the method for demonstrating compliance on an ongoing basis between the annual compliance dates.

Anticipated Future Operation Characteristics

Longview routinely dispatches as a base load unit within the competitive PJM wholesale market. Many times, this facility dispatches ahead of gas fired combined cycle facilities. The ability to reliably deliver power under extreme cold weather with a secured fuel source provides the grid with essential resilience and affordability.

[28] *See* 84 Fed. Reg. 32520, 32552 (July 8, 2019).

The future of an open and competitive marketplace is not subject to definitive future outcomes and, therefore, cannot be effectively forecasted to gain certainty to 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.

It is because of this reasoning that LVP can only forecast what a near-term expectation of net generation, capacity factors and maintenance requirements will be. Those 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. Any further attempted prediction of future operations is impossible; however, this impossibility did not affect LVP's analysis required of it under the ACE Rule as contained in this application.

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%

Figure 22. Table of LVP Anticipated Future Operation Characteristics

In evaluating the HRI technologies, LVP did not rule any of them out simply by cost alone. Specifically, for the O&M technologies, LVP has already implemented all the measures noted in the ACE Rule and believe it is financially feasible to implement these measures. Thus, the DAQ does not believe the projected fuel and O&M costs are relevant in establishing 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 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.

Regulatory Conclusion

LVP has applied for this permit under 45 CSR 13 to establish a carbon dioxide standard under Subpart UUUUa. As part of this application process, LVP submitted a complete application, paid the application fee, and published a Class I Legal Ad in the *Dominion Post* on July 17, 2020.

The proposed changes in this application do not affect the unit (PC Boiler) status or ability to comply with any existing applicable permit limitation or emission standard.

The requirements under this permit are only "state enforceable" until the Administrator approves the State Plan that relies on these limitations meet the state's mandate in Subpart UUUUa. Therefore, these requirements are not required to be incorporated into the facility's Title V Operating Permit until then. The DAQ intends to include this permit as part of a State Plan to satisfy the requirements of Subpart UUUUa with the established standards of performance.

Once EPA takes final action on the State Plan that relies on the requirements in this permit, then these requirements are recognized as new applicable requirements and must be incorporated into the facility's Title V Operating Permit. LVP can submit a Significant Modification to have these new applicable requirements be incorporated into the operating permit. If the time that when these requirements become new applicable requirements is less than the 18 months from of the renewal date of LVP's operating permit, then these requirements will be incorporated as part of the renewal process. Should LVP fail to submit a Significant Modification in a timely fashion for when the date that these permitted requirements become the new applicable requirements that is beyond 18 months from renewal date, then the DAQ will use the re-opening provisions of 45 CSR 30 to incorporated them into LVP Title V Operating Permit. The specific timing of when the their Title V Operating Permit must be re-opened will be determined when the EPA Administrator approves the State Plan that relies on the requirements in this permit to satisfy the mandates in Subpart UUUUa for the State of West Virginia in accordance with 45 CSR 30-6.6.

MONITORING OF OPERATIONS

LVP proposed using Part 60 CEMs to continuously measure the carbon dioxide emissions from the unit. LVP operates a CEMS that conforms to the Part 75 monitoring requirements which includes measuring carbon dioxide emissions. The Part 75 monitoring, recordkeeping, reporting (MRR) requirements were developed initially for the Acid Rain Trading Program.[29] It is relied upon for other trading programs, as well such as the CSAPR Trading Programs. The Part 75 requirements include bias adjustment factors based on annual relative accuracy test audit (RATA) testing. 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. Part 75 requires the use

[29] 40 CFR 75.

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.

Subpart UUUUa requires states to establish a carbon dioxide emission standard on a mass rate in terms of energy output basis (e.g., lb/MWh), which is different than mass emissions (tons/year) required by Part 75.

Subpart TTTT of Part 60 has establish procedures for monitoring carbon dioxide emissions to show compliance with a carbon dioxide 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 CFR Part 75 would be applied to determine the hourly CO_2 mass emissions.

The permit has adopted the monitoring requirements and definition of valid data for Subpart TTTT.[30] The other parameters that need to be monitored to fully implement the proposed standard are the gross and auxiliary loads for the facility.

Subpart TTTT requires new EGUs to maintain their CEMS availability to no less than 95% on unit operating time basis. The historical average downtime for a LVP CO_2 monitor is 0.6 %. Thus, the monitor uptime requirement from Subpart TTTT is clearly achievable and reasonable for LVP.

Subpart UUUUa requires a procedure to account for the emissions where required data would otherwise be incomplete from the monitoring system.[31] Part 75 has alternative methods for determining CO_2 emissions. One of these methods, Appendix G of Part 75, relies on using carbon content of the fuel (coal), loss of ignition (LOI) in the flyash, and any increase of CO_2 due to scrubbing operations in controlling sulfur dioxide emissions. Therefore, any missing CO_2 emissions data below the 95% threshold shall be accounted for by substituting the missing data using Appendix G procedures for determining CO_2 emissions.[32]

The proposed standard is established around using load bins which are defined using the gross generation from the unit with a weighted average approach basis on hours of operating in the respective bin. To properly implement this standard, LVP will need to monitor operating time and

[30] 40 CFR 60.5535(b)(1) & 60.5540(a)(1).
[31] 40 CFR 60.5785a(a)(2)(vi)
[32] 40 CFR 75, Appendix G to Part 75 – Determination of CO_2 Emissions

gross generation from the unit, which it currently does for commercial reasons. The existing monitor system should be easily configured and programed to track and record the operating time that the unit operated in the respective load bin.

The changes that LVP will have to make to their existing monitoring system is to record the auxiliary loads to determine the net generation from the unit in the data acquisition system, which is needed to demonstration compliance with the standards of performance. LVP currently does this on a separate data collection system that is independent of the data acquisition system for the CEMs.

To ensure that LVP maintains the BSERs, LVP proposes to monitor the parameters used by the OPM system to determine the hourly heat rate. The OPM heat rate on an annual basis is the best single parameter to indicate whether LVP is truly maintaining the HRI or allowing the HRI programs to become stagnant.

RECOMMENDATION TO DIRECTOR

The information provided in the permit application indicates the proposed carbon dioxide emission standard for the PC Boiler satisfies all the requirements of Subpart UUUUa of 40 CFR Part 60. The unit can operate in accordance with the established standard in the draft permit. Therefore, the writer recommends granting Longview Power LLC a Construction Permit for establishing a carbon dioxide emission standard for their existing coal fired electric generating unit at the Maidsville Facility located in Maidsville, West Virginia.

Edward S. Andrews

Digitally signed by Edward S. Andrews
Date: 2020.10.08 17:16:31 -04'00'

Edward S. Andrews, P.E.
Engineer

Appendix A

Level 1 & Level 2 CO_2 Standard of Performance Projected out to Year 2046

For

Longview Power LLC's PC Boiler

Longview Power CO_2 Rate Degradation Table

Starting Year	**2021**	
Degradation	**0.4%**	annually
Recovery	**0.7%**	per 5 years

Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2**
Degradation	**0.0%**	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0
Recovery	**0.0%**	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0

Year	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**		
Year	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**		
Degradation	**0.4%**	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%		
Recovery	**0.0%**	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%		

Level 1 - Annual CO_2 Standard of Performance (lbs/MWHG)

Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2**
Bin														
0	**9,864**	9,903	9,943	9,983	9,953	9,992	10,032	10,073	10,113	10,082	10,123	10,163	10,204	10,

Level 1 - Annual CO_2 Standard of Performance (lbs/MWHG) Continued

Year	15	16	17	18	19	20	21	22	23	24	25			
Year	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046			
Bin														
0	10,254	10,295	10,337	10,378	10,346	10,388	10,429	10,471	10,513	10,481	10,523			

Level 1 - Annual CO_2 Standard of Performance (lbs/MWHN)

Year	0	1	2	3	4	5	6	7	8	9	10	11	12	
Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2
Bin														
1	**2,230**	2,239	2,248	2,257	2,250	2,259	2,268	2,277	2,286	2,279	2,288	2,298	2,307	2,3
2	**2,108**	2,116	2,125	2,133	2,127	2,135	2,144	2,153	2,161	2,155	2,163	2,172	2,181	2,1
3	**2,050**	2,058	2,066	2,075	2,068	2,077	2,085	2,093	2,102	2,095	2,104	2,112	2,121	2,1
4	**2,002**	2,010	2,018	2,026	2,020	2,028	2,036	2,044	2,052	2,046	2,054	2,063	2,071	2,0
5	**1,958**	1,966	1,974	1,982	1,976	1,983	1,991	1,999	2,007	2,001	2,009	2,017	2,025	2,0

Level 1 - Annual CO_2 Standard of Performance (lbs/MWHN)

Year	15	16	17	18	19	20	21	22	23	24	25			
Year	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046			

Bin													
1	**2,318**	2,328	2,337	2,346	2,339	2,348	2,358	2,367	2,377	2,370	2,379		
2	**2,191**	2,200	2,209	2,218	2,211	2,220	2,229	2,238	2,247	2,240	2,249		
3	**2,131**	2,140	2,148	2,157	2,150	2,159	2,167	2,176	2,185	2,178	2,187		
4	**2,081**	2,090	2,098	2,106	2,100	2,108	2,117	2,125	2,134	2,127	2,136		
5	**2,035**	2,044	2,052	2,060	2,054	2,062	2,070	2,079	2,087	2,081	2,089		

Level 2 - Annual CO_2 Standard of Performance (lbs/MWHN)

Year	0	1	2	3	4	5	6	7	8	9	10	11	12	
Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2
Bin														
1	**2,453**	2,463	2,473	2,483	2,475	2,485	2,495	2,505	2,515	2,507	2,517	2,527	2,537	2,5
2	**2,319**	2,328	2,337	2,347	2,340	2,349	2,358	2,368	2,377	2,370	2,380	2,389	2,399	2,4
3	**2,255**	2,264	2,273	2,282	2,275	2,284	2,293	2,303	2,312	2,305	2,314	2,323	2,333	2,3
4	**2,202**	2,211	2,220	2,229	2,222	2,231	2,240	2,249	2,258	2,251	2,260	2,269	2,278	2,2
5	**2,154**	2,162	2,171	2,180	2,173	2,182	2,191	2,199	2,208	2,201	2,210	2,219	2,228	2,2

Level 2 - Annual CO_2 Standard of Performance (lbs/MWHN)

	15	16	17	18	19	20	21	22	23	24	25			
	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046			
Bin														
1	**2,550**	2,560	2,571	2,581	2,573	2,583	2,594	2,604	2,614	2,606	2,617	-	-	-
2	**2,411**	2,420	2,430	2,440	2,432	2,442	2,452	2,462	2,471	2,464	2,474	-	-	-
3	**2,344**	2,354	2,363	2,372	2,365	2,375	2,384	2,394	2,403	2,396	2,406	-	-	-
4	**2,289**	2,298	2,308	2,317	2,310	2,319	2,328	2,338	2,347	2,340	2,349	-	-	-
5	**2,239**	2,248	2,257	2,266	2,259	2,268	2,277	2,286	2,296	2,289	2,298	-	-	-

Appendix B

Analysis of Emissions Data Using R

For

Longview Power LLC's PC Boiler

Background of R Programming Language

R is a programming language and free software environment for statistical computing and graphics supported by the R Foundation for Statistical Computing. The R language is widely used among statisticians for developing statistical software and data analysis. Studies of scholarly literature databases show substantial increases in R popularity; as of September 2020, R ranks 9th in the TIOBE index, a measure of popularity of programming languages.

A GNU package, the official R software environment is written primarily in C, Fortran, and R itself (thus, it is partially self-hosting) and is freely available under the GNU General Public License. Pre-compiled executables are provided for various operating systems. Although R has a command line interface, there are several third-party graphical user interfaces, such as RStudio (https://rstudio.com/).

Description of Data Analysis Using R

Longview Power provided the DAQ with an Excel file containing CO_2 emissions data collected from a 40 CFR Part 75 certified continuously emission monitoring system (CEMS). This data was analyzed to determine CO_2 emissions as a function of power output from the facility (lb CO_2/MWh).

To aid in this process, an R script was written to analyze emissions data. This script took data provided in the Excel file provided by Longview Power and calculated 12- and 18-month rolling averages CO_2 emissions values for each load bin. The R script summarized these calculations in several Comma Separated Values (CSV) files: one file for each load bin and a summary file.

R Script

```
library(data.table)
library(zoo)

# specify the working directory - you must manually change backslashes to forward slashes!

# setting the working directory allows you to reference files by name rather than the file path

# if you intend to use files from multiple folders you may not want to set the working directory
setwd("C:/Users/E007604/Desktop/R projects/DAQ R project")

# specify csv
rd <- read.csv("RawData_2016-2020.csv", header = TRUE,  na.strings = c("NA"))

# if you did not specify the working directory, comment out the read.csv line above (using #) and
uncomment the read.csv line below

# remember to manually change backslashes (\) to forward slashes (/) as R doesn't like backslashes
in directory addresses

# rd <- read.csv("C:/Users/E007604/Desktop/R projects/DAQ R project/RawData_2016-2020.csv",
header = TRUE,  na.strings = c("NA"))

# creates column for just the date
rd[,"Date"] <- as.POSIXct(substr(rd$Date.Hour, 1,10), format = "%m/%d/%Y")

# view the structure of the file and identify any columns which may need reformatted
str(rd)

# formats numeric columns as numeric while suppressing warnings
rd$BOILER01.CO2 <- suppressWarnings(as.numeric(rd$BOILER01.CO2))
rd$BOILER01.CO2T.HR <- suppressWarnings(as.numeric(rd$BOILER01.CO2T.HR))
rd$BOILER01.FLOWSCFH <- suppressWarnings(as.numeric(rd$BOILER01.FLOWSCFH))
rd$BOILER01.LOAD_MW <- suppressWarnings(as.numeric(rd$BOILER01.LOAD_MW))
rd$BOILER01.UNITOPHR <- suppressWarnings(as.numeric(rd$BOILER01.UNITOPHR))
rd$lbs.CO2.hr <- suppressWarnings(as.numeric(rd$lbs.CO2.hr))
rd$lbs.CO2.MWh.Net <- suppressWarnings(as.numeric(rd$lbs.CO2.MWh.Net))
rd$lbs.CO2.MWh.Gross <- suppressWarnings(as.numeric(rd$lbs.CO2.MWh.Gross))

# View the structure of the file to see changes
str(rd)


# reassigns empty values (NA) to 0
```

```
rd$BOILER01.CO2[is.na(rd$BOILER01.CO2)] <- 0
rd$BOILER01.CO2T.HR[is.na(rd$BOILER01.CO2T.HR)] <- 0
rd$BOILER01.FLOWSCFH[is.na(rd$BOILER01.FLOWSCFH)] <- 0
rd$BOILER01.LOAD_MW[is.na(rd$BOILER01.LOAD_MW)] <- 0
rd$BOILER01.UNITOPHR[is.na(rd$BOILER01.UNITOPHR)] <- 0
rd$lbs.CO2.hr[is.na(rd$lbs.CO2.hr)] <- 0
rd$lbs.CO2.MWh.Net[is.na(rd$lbs.CO2.MWh.Net)] <- 0
rd$lbs.CO2.MWh.Gross[is.na(rd$lbs.CO2.MWh.Gross)] <- 0

# define LoadBin based on MW generated
rd[,"LoadBin"] <- ifelse(rd$BOILER01.LOAD_MW < 313, "LB-0",
ifelse(rd$BOILER01.LOAD_MW < 407, "LB-1", ifelse(rd$BOILER01.LOAD_MW <501, "LB-2",
ifelse(rd$BOILER01.LOAD_MW <595, "LB-3", ifelse(rd$BOILER01.LOAD_MW <689, "LB-
4",ifelse(rd$BOILER01.LOAD_MW >=689, "LB-5","error"))))))

# displays unique LoadBin values
# used as a manual/visual check to make sure values are as expected
unique(rd$LoadBin)

# creates a new table with only the necessary info
rdsub <- rd[c(1:nrow(rd)), c(10, 11, 3, 5)]

# renames columns
names(rdsub)[names(rdsub) == "BOILER01.CO2T.HR"] <- "CO2T"
names(rdsub)[names(rdsub) == "BOILER01.LOAD_MW"] <- "MWg"

# view subset data
View(rdsub)

# reformats date
setDT(rdsub)[,Date := as.POSIXct(substr(Date, 1,10), format = "%Y-%m-%d")]

# collapses hourly data into daily sum by load-bin
CO2T_Daily <- rdsub[, .(CO2T = sum(CO2T)), by = list(Date, LoadBin)]
MWg_Daily <- rdsub[, .(MWg = sum(MWg)), by = list(Date, LoadBin)]

# merges daily sums
Daily_Merge  <- merge(CO2T_Daily, MWg_Daily, by.CO2T_Daily = list(Date, LoadBin), sort =
TRUE)

# extracts month-year
rdsub$Month_Yr <- format(as.Date(rdsub$Date), "%Y-%m")

# collapses daily data into monthly sum by load-bin
CO2T_Monthly <- rdsub[, .(CO2T = sum(CO2T)), by = list(Month_Yr, LoadBin)]
```

```
MWg_Monthly <- rdsub[, .(MWg = sum(MWg)), by = list(Month_Yr, LoadBin)]

# merges monthly sums
Monthly_Merge  <- merge(CO2T_Monthly, MWg_Monthly, by.CO2T_Monthly = list(Month_Yr,
LoadBin), sort = TRUE)

# creates subsets for each Load-Bin
LB0sub <- Monthly_Merge[Monthly_Merge$LoadBin == "LB-0",]
LB1sub <- Monthly_Merge[Monthly_Merge$LoadBin == "LB-1",]
LB2sub <- Monthly_Merge[Monthly_Merge$LoadBin == "LB-2",]
LB3sub <- Monthly_Merge[Monthly_Merge$LoadBin == "LB-3",]
LB4sub <- Monthly_Merge[Monthly_Merge$LoadBin == "LB-4",]
LB5sub <- Monthly_Merge[Monthly_Merge$LoadBin == "LB-5",]

# calculates rolling 12- and 18- month average for CO2T and MWg
LB0sub[, "roll12CO2"] <- rollmeanr(x = LB0sub$CO2T, k = 12, fill = NA)
LB0sub[, "roll12MWg"] <- rollmeanr(x = LB0sub$MWg, k = 12, fill = NA)
LB0sub[, "roll18CO2"] <- rollmeanr(x = LB0sub$CO2T, k = 18, fill = NA)
LB0sub[, "roll18MWg"] <- rollmeanr(x = LB0sub$MWg, k = 18, fill = NA)
LB1sub[, "roll12CO2"] <- rollmeanr(x = LB1sub$CO2T, k = 12, fill = NA)
LB1sub[, "roll12MWg"] <- rollmeanr(x = LB1sub$MWg, k = 12, fill = NA)
LB1sub[, "roll18CO2"] <- rollmeanr(x = LB1sub$CO2T, k = 18, fill = NA)
LB1sub[, "roll18MWg"] <- rollmeanr(x = LB1sub$MWg, k = 18, fill = NA)
LB2sub[, "roll12CO2"] <- rollmeanr(x = LB2sub$CO2T, k = 12, fill = NA)
LB2sub[, "roll12MWg"] <- rollmeanr(x = LB2sub$MWg, k = 12, fill = NA)
LB2sub[, "roll18CO2"] <- rollmeanr(x = LB2sub$CO2T, k = 18, fill = NA)
LB2sub[, "roll18MWg"] <- rollmeanr(x = LB2sub$MWg, k = 18, fill = NA)
LB3sub[, "roll12CO2"] <- rollmeanr(x = LB3sub$CO2T, k = 12, fill = NA)
LB3sub[, "roll12MWg"] <- rollmeanr(x = LB3sub$MWg, k = 12, fill = NA)
LB3sub[, "roll18CO2"] <- rollmeanr(x = LB3sub$CO2T, k = 18, fill = NA)
LB3sub[, "roll18MWg"] <- rollmeanr(x = LB3sub$MWg, k = 18, fill = NA)
LB4sub[, "roll12CO2"] <- rollmeanr(x = LB4sub$CO2T, k = 12, fill = NA)
LB4sub[, "roll12MWg"] <- rollmeanr(x = LB4sub$MWg, k = 12, fill = NA)
LB4sub[, "roll18CO2"] <- rollmeanr(x = LB4sub$CO2T, k = 18, fill = NA)
LB4sub[, "roll18MWg"] <- rollmeanr(x = LB4sub$MWg, k = 18, fill = NA)
LB5sub[, "roll12CO2"] <- rollmeanr(x = LB5sub$CO2T, k = 12, fill = NA)
LB5sub[, "roll12MWg"] <- rollmeanr(x = LB5sub$MWg, k = 12, fill = NA)
LB5sub[, "roll18CO2"] <- rollmeanr(x = LB5sub$CO2T, k = 18, fill = NA)
LB5sub[, "roll18MWg"] <- rollmeanr(x = LB5sub$MWg, k = 18, fill = NA)

# views the data subsets
View(LB0sub)
View(LB1sub)
View(LB2sub)
View(LB3sub)
```

```
View(LB4sub)
View(LB5sub)

# combines individual LoadBin subsets into one dataset called RollingSummary
RollingSummary <- rbind(LB0sub, LB1sub, LB2sub, LB3sub, LB4sub, LB5sub)

# views the dataset
View(RollingSummary)

# saves the data subsets as csv
# if a working directory has not been defined the file path will need to be included
write.csv(LB0sub, "LB0sub.csv")
write.csv(LB1sub, "LB1sub.csv")
write.csv(LB2sub, "LB2sub.csv")
write.csv(LB3sub, "LB3sub.csv")
write.csv(LB4sub, "LB4sub.csv")
write.csv(LB5sub, "LB5sub.csv")
write.csv(RollingSummary, "RollingSummary.csv")

# if you did not specify the working directory, comment out the write.csv lines above (using #) and
uncomment the write.csv lines below
# remember to manually change backslashes (\) to forward slashes (/) as R doesn't like backslashes
in directory addresses
#write.csv(LB0sub, "C:/Users/E007604/Desktop/R projects/DAQ R project/LB0sub.csv")
#write.csv(LB1sub, "C:/Users/E007604/Desktop/R projects/DAQ R project/LB1sub.csv")
#write.csv(LB2sub, "C:/Users/E007604/Desktop/R projects/DAQ R project/LB2sub.csv")
#write.csv(LB3sub, "C:/Users/E007604/Desktop/R projects/DAQ R project/LB3sub.csv")
#write.csv(LB4sub, "C:/Users/E007604/Desktop/R projects/DAQ R project/LB4sub.csv")
#write.csv(LB5sub, "C:/Users/E007604/Desktop/R projects/DAQ R project/LB5sub.csv")
#write.csv(RollingSummary, "C:/Users/E007604/Desktop/R projects/DAQ R
project/RollingSummary.csv")
```

Appendix A

Level 1 & Level 2 CO_2 Standard of Performance Projected out to Year 2046

For

Longview Power LLC's PC Boiler

Longview Power CO_2 Rate Degradation Tabl

Starting Year	**2021**	
Degradation	**0.4%**	annually
Recovery	**0.7%**	per 5 years

Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2**
Degradation	**0.0%**	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0
Recovery	**0.0%**	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0
Year	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**			
Year	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**			
Degradation	**0.4%**	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%			
Recovery	**0.0%**	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%			

Level 1 - Annual CO_2 Standard of Performance (lbs/MWHG)

Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2**
Bin														
0	**9,864**	9,903	9,943	9,983	9,953	9,992	10,032	10,073	10,113	10,082	10,123	10,163	10,204	10,

Level 1 - Annual CO_2 Standard of Performance (lbs/MWHG) Continued

Year	15	16	17	18	19	20	21	22	23	24	25			
Year	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046			
Bin														
0	10,254	10,295	10,337	10,378	10,346	10,388	10,429	10,471	10,513	10,481	10,523			

Level 1 - Annual CO_2 Standard of Performance (lbs/MWHN)

Year	0	1	2	3	4	5	6	7	8	9	10	11	12	
Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2
Bin														
1	**2,230**	2,239	2,248	2,257	2,250	2,259	2,268	2,277	2,286	2,279	2,288	2,298	2,307	2,3
2	**2,108**	2,116	2,125	2,133	2,127	2,135	2,144	2,153	2,161	2,155	2,163	2,172	2,181	2,1
3	**2,050**	2,058	2,066	2,075	2,068	2,077	2,085	2,093	2,102	2,095	2,104	2,112	2,121	2,1
4	**2,002**	2,010	2,018	2,026	2,020	2,028	2,036	2,044	2,052	2,046	2,054	2,063	2,071	2,0
5	**1,958**	1,966	1,974	1,982	1,976	1,983	1,991	1,999	2,007	2,001	2,009	2,017	2,025	2,0

Level 1 - Annual CO_2 Standard of Performance (lbs/MWHN)

Year	15	16	17	18	19	20	21	22	23	24	25			
Year	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046			

Bin														
1	**2,318**	2,328	2,337	2,346	2,339	2,348	2,358	2,367	2,377	2,370	2,379			
2	**2,191**	2,200	2,209	2,218	2,211	2,220	2,229	2,238	2,247	2,240	2,249			
3	**2,131**	2,140	2,148	2,157	2,150	2,159	2,167	2,176	2,185	2,178	2,187			
4	**2,081**	2,090	2,098	2,106	2,100	2,108	2,117	2,125	2,134	2,127	2,136			
5	**2,035**	2,044	2,052	2,060	2,054	2,062	2,070	2,079	2,087	2,081	2,089			

Level 2 - Annual CO_2 Standard of Performance (lbs/MWHN)

Year	0	1	2	3	4	5	6	7	8	9	10	11	12	
Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2
Bin														
1	**2,453**	2,463	2,473	2,483	2,475	2,485	2,495	2,505	2,515	2,507	2,517	2,527	2,537	2,5
2	**2,319**	2,328	2,337	2,347	2,340	2,349	2,358	2,368	2,377	2,370	2,380	2,389	2,399	2,4
3	**2,255**	2,264	2,273	2,282	2,275	2,284	2,293	2,303	2,312	2,305	2,314	2,323	2,333	2,3
4	**2,202**	2,211	2,220	2,229	2,222	2,231	2,240	2,249	2,258	2,251	2,260	2,269	2,278	2,2
5	**2,154**	2,162	2,171	2,180	2,173	2,182	2,191	2,199	2,208	2,201	2,210	2,219	2,228	2,2

Level 2 - Annual CO_2 Standard of Performance (lbs/MWHN)

	15	16	17	18	19	20	21	22	23	24	25			
	2036	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**			
Bin														
1	**2,550**	2,560	2,571	2,581	2,573	2,583	2,594	2,604	2,614	2,606	2,617	-	-	-
2	**2,411**	2,420	2,430	2,440	2,432	2,442	2,452	2,462	2,471	2,464	2,474	-	-	-
3	**2,344**	2,354	2,363	2,372	2,365	2,375	2,384	2,394	2,403	2,396	2,406	-	-	-
4	**2,289**	2,298	2,308	2,317	2,310	2,319	2,328	2,338	2,347	2,340	2,349	-	-	-
5	**2,239**	2,248	2,257	2,266	2,259	2,268	2,277	2,286	2,296	2,289	2,298	-	-	-

Appendix B

Analysis of Emissions Data Using R

For

Longview Power LLC’s PC Boiler

Background of R Programming Language

R is a programming language and free software environment for statistical computing and graphics supported by the R Foundation for Statistical Computing. The R language is widely used among statisticians for developing statistical software and data analysis. Studies of scholarly literature databases show substantial increases in R popularity; as of September 2020, R ranks 9th in the TIOBE index, a measure of popularity of programming languages.

A GNU package, the official R software environment is written primarily in C, Fortran, and R itself (thus, it is partially self-hosting) and is freely available under the GNU General Public License. Pre-compiled executables are provided for various operating systems. Although R has a command line interface, there are several third-party graphical user interfaces, such as RStudio (https://rstudio.com/).

Description of Data Analysis Using R

Longview Power provided the DAQ with an Excel file containing CO_2 emissions data collected from a 40 CFR Part 75 certified continuously emission monitoring system (CEMS). This data was analyzed to determine CO_2 emissions as a function of power output from the facility (lb CO_2/MWh).

To aid in this process, an R script was written to analyze emissions data. This script took data provided in the Excel file provided by Longview Power and calculated 12- and 18-month rolling averages CO_2 emissions values for each load bin. The R script summarized these calculations in several Comma Separated Values (CSV) files: one file for each load bin and a summary file.

R Script

```
library(data.table)
library(zoo)

# specify the working directory - you must manually change backslashes to forward slashes!

# setting the working directory allows you to reference files by name rather than the file path

# if you intend to use files from multiple folders you may not want to set the working directory
setwd("C:/Users/E007604/Desktop/R projects/DAQ R project")

# specify csv
rd <- read.csv("RawData_2016-2020.csv", header = TRUE,  na.strings = c("NA"))

# if you did not specify the working directory, comment out the read.csv line above (using #) and
uncomment the read.csv line below

# remember to manually change backslashes (\) to forward slashes (/) as R doesn't like backslashes
in directory addresses

# rd <- read.csv("C:/Users/E007604/Desktop/R projects/DAQ R project/RawData_2016-2020.csv",
header = TRUE,  na.strings = c("NA"))

# creates column for just the date
rd[,"Date"] <- as.POSIXct(substr(rd$Date.Hour, 1,10), format = "%m/%d/%Y")

# view the structure of the file and identify any columns which may need reformatted
str(rd)

# formats numeric columns as numeric while suppressing warnings
rd$BOILER01.CO2 <- suppressWarnings(as.numeric(rd$BOILER01.CO2))
rd$BOILER01.CO2T.HR <- suppressWarnings(as.numeric(rd$BOILER01.CO2T.HR))
rd$BOILER01.FLOWSCFH <- suppressWarnings(as.numeric(rd$BOILER01.FLOWSCFH))
rd$BOILER01.LOAD_MW <- suppressWarnings(as.numeric(rd$BOILER01.LOAD_MW))
rd$BOILER01.UNITOPHR <- suppressWarnings(as.numeric(rd$BOILER01.UNITOPHR))
rd$lbs.CO2.hr <- suppressWarnings(as.numeric(rd$lbs.CO2.hr))
rd$lbs.CO2.MWh.Net <- suppressWarnings(as.numeric(rd$lbs.CO2.MWh.Net))
rd$lbs.CO2.MWh.Gross <- suppressWarnings(as.numeric(rd$lbs.CO2.MWh.Gross))

# View the structure of the file to see changes
str(rd)


# reassigns empty values (NA) to 0
```

```
rd$BOILER01.CO2[is.na(rd$BOILER01.CO2)] <- 0
rd$BOILER01.CO2T.HR[is.na(rd$BOILER01.CO2T.HR)] <- 0
rd$BOILER01.FLOWSCFH[is.na(rd$BOILER01.FLOWSCFH)] <- 0
rd$BOILER01.LOAD_MW[is.na(rd$BOILER01.LOAD_MW)] <- 0
rd$BOILER01.UNITOPHR[is.na(rd$BOILER01.UNITOPHR)] <- 0
rd$lbs.CO2.hr[is.na(rd$lbs.CO2.hr)] <- 0
rd$lbs.CO2.MWh.Net[is.na(rd$lbs.CO2.MWh.Net)] <- 0
rd$lbs.CO2.MWh.Gross[is.na(rd$lbs.CO2.MWh.Gross)] <- 0

# define LoadBin based on MW generated
rd[,"LoadBin"] <- ifelse(rd$BOILER01.LOAD_MW < 313, "LB-0",
ifelse(rd$BOILER01.LOAD_MW < 407, "LB-1", ifelse(rd$BOILER01.LOAD_MW <501, "LB-2",
ifelse(rd$BOILER01.LOAD_MW <595, "LB-3", ifelse(rd$BOILER01.LOAD_MW <689, "LB-
4",ifelse(rd$BOILER01.LOAD_MW >=689, "LB-5","error"))))))

# displays unique LoadBin values
# used as a manual/visual check to make sure values are as expected
unique(rd$LoadBin)

# creates a new table with only the necessary info
rdsub <- rd[c(1:nrow(rd)), c(10, 11, 3, 5)]

# renames columns
names(rdsub)[names(rdsub) == "BOILER01.CO2T.HR"] <- "CO2T"
names(rdsub)[names(rdsub) == "BOILER01.LOAD_MW"] <- "MWg"

# view subset data
View(rdsub)

# reformats date
setDT(rdsub)[,Date := as.POSIXct(substr(Date, 1,10), format = "%Y-%m-%d")]

# collapses hourly data into daily sum by load-bin
CO2T_Daily <- rdsub[, .(CO2T = sum(CO2T)), by = list(Date, LoadBin)]
MWg_Daily <- rdsub[, .(MWg = sum(MWg)), by = list(Date, LoadBin)]

# merges daily sums
Daily_Merge  <- merge(CO2T_Daily, MWg_Daily, by.CO2T_Daily = list(Date, LoadBin), sort =
TRUE)

# extracts month-year
rdsub$Month_Yr <- format(as.Date(rdsub$Date), "%Y-%m")

# collapses daily data into monthly sum by load-bin
CO2T_Monthly <- rdsub[, .(CO2T = sum(CO2T)), by = list(Month_Yr, LoadBin)]
```

```
MWg_Monthly <- rdsub[, .(MWg = sum(MWg)), by = list(Month_Yr, LoadBin)]

# merges monthly sums
Monthly_Merge  <- merge(CO2T_Monthly, MWg_Monthly, by.CO2T_Monthly = list(Month_Yr,
LoadBin), sort = TRUE)

# creates subsets for each Load-Bin
LB0sub <- Monthly_Merge[Monthly_Merge$LoadBin == "LB-0",]
LB1sub <- Monthly_Merge[Monthly_Merge$LoadBin == "LB-1",]
LB2sub <- Monthly_Merge[Monthly_Merge$LoadBin == "LB-2",]
LB3sub <- Monthly_Merge[Monthly_Merge$LoadBin == "LB-3",]
LB4sub <- Monthly_Merge[Monthly_Merge$LoadBin == "LB-4",]
LB5sub <- Monthly_Merge[Monthly_Merge$LoadBin == "LB-5",]

# calculates rolling 12- and 18- month average for CO2T and MWg
LB0sub[, "roll12CO2"] <- rollmeanr(x = LB0sub$CO2T, k = 12, fill = NA)
LB0sub[, "roll12MWg"] <- rollmeanr(x = LB0sub$MWg, k = 12, fill = NA)
LB0sub[, "roll18CO2"] <- rollmeanr(x = LB0sub$CO2T, k = 18, fill = NA)
LB0sub[, "roll18MWg"] <- rollmeanr(x = LB0sub$MWg, k = 18, fill = NA)
LB1sub[, "roll12CO2"] <- rollmeanr(x = LB1sub$CO2T, k = 12, fill = NA)
LB1sub[, "roll12MWg"] <- rollmeanr(x = LB1sub$MWg, k = 12, fill = NA)
LB1sub[, "roll18CO2"] <- rollmeanr(x = LB1sub$CO2T, k = 18, fill = NA)
LB1sub[, "roll18MWg"] <- rollmeanr(x = LB1sub$MWg, k = 18, fill = NA)
LB2sub[, "roll12CO2"] <- rollmeanr(x = LB2sub$CO2T, k = 12, fill = NA)
LB2sub[, "roll12MWg"] <- rollmeanr(x = LB2sub$MWg, k = 12, fill = NA)
LB2sub[, "roll18CO2"] <- rollmeanr(x = LB2sub$CO2T, k = 18, fill = NA)
LB2sub[, "roll18MWg"] <- rollmeanr(x = LB2sub$MWg, k = 18, fill = NA)
LB3sub[, "roll12CO2"] <- rollmeanr(x = LB3sub$CO2T, k = 12, fill = NA)
LB3sub[, "roll12MWg"] <- rollmeanr(x = LB3sub$MWg, k = 12, fill = NA)
LB3sub[, "roll18CO2"] <- rollmeanr(x = LB3sub$CO2T, k = 18, fill = NA)
LB3sub[, "roll18MWg"] <- rollmeanr(x = LB3sub$MWg, k = 18, fill = NA)
LB4sub[, "roll12CO2"] <- rollmeanr(x = LB4sub$CO2T, k = 12, fill = NA)
LB4sub[, "roll12MWg"] <- rollmeanr(x = LB4sub$MWg, k = 12, fill = NA)
LB4sub[, "roll18CO2"] <- rollmeanr(x = LB4sub$CO2T, k = 18, fill = NA)
LB4sub[, "roll18MWg"] <- rollmeanr(x = LB4sub$MWg, k = 18, fill = NA)
LB5sub[, "roll12CO2"] <- rollmeanr(x = LB5sub$CO2T, k = 12, fill = NA)
LB5sub[, "roll12MWg"] <- rollmeanr(x = LB5sub$MWg, k = 12, fill = NA)
LB5sub[, "roll18CO2"] <- rollmeanr(x = LB5sub$CO2T, k = 18, fill = NA)
LB5sub[, "roll18MWg"] <- rollmeanr(x = LB5sub$MWg, k = 18, fill = NA)

# views the data subsets
View(LB0sub)
View(LB1sub)
View(LB2sub)
View(LB3sub)
```

```
View(LB4sub)
View(LB5sub)

# combines individual LoadBin subsets into one dataset called RollingSummary
RollingSummary <- rbind(LB0sub, LB1sub, LB2sub, LB3sub, LB4sub, LB5sub)

# views the dataset
View(RollingSummary)

# saves the data subsets as csv
# if a working directory has not been defined the file path will need to be included
write.csv(LB0sub, "LB0sub.csv")
write.csv(LB1sub, "LB1sub.csv")
write.csv(LB2sub, "LB2sub.csv")
write.csv(LB3sub, "LB3sub.csv")
write.csv(LB4sub, "LB4sub.csv")
write.csv(LB5sub, "LB5sub.csv")
write.csv(RollingSummary, "RollingSummary.csv")

# if you did not specify the working directory, comment out the write.csv lines above (using #) and
uncomment the write.csv lines below
# remember to manually change backslashes (\) to forward slashes (/) as R doesn't like backslashes
in directory addresses
#write.csv(LB0sub, "C:/Users/E007604/Desktop/R projects/DAQ R project/LB0sub.csv")
#write.csv(LB1sub, "C:/Users/E007604/Desktop/R projects/DAQ R project/LB1sub.csv")
#write.csv(LB2sub, "C:/Users/E007604/Desktop/R projects/DAQ R project/LB2sub.csv")
#write.csv(LB3sub, "C:/Users/E007604/Desktop/R projects/DAQ R project/LB3sub.csv")
#write.csv(LB4sub, "C:/Users/E007604/Desktop/R projects/DAQ R project/LB4sub.csv")
#write.csv(LB5sub, "C:/Users/E007604/Desktop/R projects/DAQ R project/LB5sub.csv")
#write.csv(RollingSummary, "C:/Users/E007604/Desktop/R projects/DAQ R
project/RollingSummary.csv")
```

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West Virginia Department of Environmental Protection

Austin Caperton
Cabinet Secretary

Construction Permit

R13-3495

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§22-5-1 et seq.) and 45 C.S.R. 13 – Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits, Permission to Commence Construction, and Procedures for Evaluation. The permittee identified at the above-referenced facility is authorized to construct the stationary sources of air pollutants identified herein in accordance with all terms and conditions of this permit.

Issued to:
Longview Power LLC
Maidsville
061-00134

____

Laura M. Crowder
Director, Division of Air Quality

Issued: DRAFT

Facility Location:	1375 Fort Martin Road Maidsville, Monongalia County, West Virginia 26541
Mailing	Same as Above
Facility Description:	Electric Generation Unit
NAICS Codes:	221112
UTM Coordinates:	580.6 km Easting • 4,306.9 km Northing • Zone 17
Permit Type:	Construction
Description of Change:	This action is for establishing a standard of performance emission limit for carbon dioxide emitted from the Pulverized Coal-Fired Steam Generating Unit (PC-Boiler) in accordance with the Emission Guidelines of 40 CFR Part 60, Subpart UUUUa.

Any person whose interest may be affected, including, but not necessarily limited to, the applicant and any person who participated in the public comment process, by a permit issued, modified or denied by the Secretary may appeal such action of the Secretary to the Air Quality Board pursuant to article one [§§22B-1-1 et seq.], Chapter 22B of the Code of West Virginia. West Virginia Code §§22-5-14.

The source is subject to 45CSR30. Changes authorized by this permit must also be incorporated into the facility's Title V operating permit. Commencement of the operations authorized by this permit shall be determined by the appropriate timing limitations associated with Title V permit revisions per 45CSR30.

Table of Contents

1.0. Emission Units.....4

2.0. General Conditions.....5

2.1. Definitions.....5
2.2. Acronyms.....5
2.3. Authority.....5
2.4. Term and Renewal.....6
2.5. Duty to Comply.....6
2.6. Duty to Provide Information.....6
2.7. Duty to Supplement and Correct Information.....6
2.8. Administrative Update.....7
2.9. Permit Modification.....7
2.10 Major Permit Modification.....7
2.11. Inspection and Entry.....7
2.12. Emergency.....7
2.13. Need to Halt or Reduce Activity Not a Defense.....8
2.14. Suspension of Activities.....8
2.15. Property Rights.....8
2.16. Severability.....8
2.17. Transferability.....8
2.18. Notification Requirements.....9
2.19. Credible Evidence.....9

3.0. Facility-Wide Requirements.....10

3.1. Limitations and Standards.....10
3.2. Monitoring Requirements.....10
3.3. Testing Requirements.....10
3.4. Recordkeeping Requirements.....11
3.5. Reporting Requirements.....12

4.0. Source-Specific Requirements.....14

4.1. Limitations and Standards.....14
4.2. Monitoring Requirements.....16
4.3. Testing Requirements.....18
4.4. Recordkeeping Requirements.....20
4.5. Reporting Requirements.....24

CERTIFICATION OF DATA ACCURACY.....25

1.0. Emission Units

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
SB1	EA1	Pulverized Coal-Fired Steam Generator (PC Boiler)	1/26/2007	6,114 MMBtu/hr	SCR/DSI/FF/WFGD

SCR – Selective Catalytic Reduction for reducing nitrogen oxides emissions
DSI – Dry Sorbent Injection for reducing acid gases emissions
FF – Fabric Filter Baghouse for reducing filterable PM emissions
WFGD – Wet Flue Gas Desulfurization for reducing sulfur dioxide emissions

2.0. General Conditions

2.1. Definitions

2.1.1. All references to the "West Virginia Air Pollution Control Act" or the "Air Pollution Control Act" mean those provisions contained in W.Va. Code §§ 22-5-1 to 22-5-18.

2.1.2. The "Clean Air Act" means those provisions contained in 42 U.S.C. §§ 7401 to 7671q, and regulations promulgated thereunder.

2.1.3. "Secretary" means the Secretary of the Department of Environmental Protection or such other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8 (45CSR§30-2.12.). The Director of the Division of Air Quality is the Secretary's designated representative for the purposes of this permit.

2.2. Acronyms

CAAA	Clean Air Act Amendments
CBI	Confidential Business Information
CEM	Continuous Emission Monitor
CES	Certified Emission Statement
C.F.R. ***or*** **CFR**	Code of Federal Regulations
CO	Carbon Monoxide
C.S.R. ***or*** **CSR**	Codes of State Rules
DAQ	Division of Air Quality
DEP	Department of Environmental Protection
dscm	Dry Standard Cubic Meter
FOIA	Freedom of Information Act
HAP	Hazardous Air Pollutant
HON	Hazardous Organic NESHAP
HP	Horsepower
lbs/hr	Pounds per Hour
LDAR	Leak Detection and Repair
M	Thousand
MACT	Maximum Achievable Control Technology
MDHI	Maximum Design Heat Input
MM	Million
MMBtu/hr ***or*** **mmbtu/hr**	Million British Thermal Units per Hour
MMCF/hr ***or*** **mmcf/hr**	Million Cubic Feet per Hour
NA	Not Applicable
NAAQS	National Ambient Air Quality Standards
NESHAPS	National Emissions Standards for Hazardous Air Pollutants
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter less than 2.5 µm in diameter
PM_{10}	Particulate Matter less than 10µm in diameter
Ppb	Pounds per Batch
Pph	Pounds per Hour
Ppm	Parts per Million
Ppm_V or ppmv	Parts per Million by Volume
PSD	Prevention of Significant Deterioration
Psi	Pounds per Square Inch
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TAP	Toxic Air Pollutant
TPY	Tons per Year
TRS	Total Reduced Sulfur
TSP	Total Suspended Particulate
USEPA	United States Environmental Protection Agency
UTM	Universal Transverse Mercator
VEE	Visual Emissions Evaluation
VOC	Volatile Organic Compounds
VOL	Volatile Organic Liquids

2.3. Authority

This permit is issued in accordance with West Virginia Air Pollution Control Act W.Va. Code §§ 22-5-1. et seq. and the following Legislative Rules promulgated thereunder:

2.3.1. 45CSR13 – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation*;

2.4. Term and Renewal

2.4.1. This Permit shall remain valid, continuous and in effect unless it is revised, suspended, revoked or otherwise changed under an applicable provision of 45CSR13 or any other applicable legislative rule;

2.5. Duty to Comply

2.5.1. The permitted facility shall be constructed and operated in accordance with the plans and specifications filed in Permit Application R13-3495, and any modifications, administrative updates, or amendments thereto. The Secretary may suspend or revoke a permit if the plans and specifications upon which the approval was based are not adhered to;
[45CSR§§13-5.10 and 10.3.]

2.5.2. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the West Virginia Code and the Clean Air Act and is grounds for enforcement action by the Secretary or USEPA;

2.5.3. Violations of any of the conditions contained in this permit, or incorporated herein by reference, may subject the permittee to civil and/or criminal penalties for each violation and further action or remedies as provided by West Virginia Code 22-5-6 and 22-5-7;

2.5.4. Approval of this permit does not relieve the permittee herein of the responsibility to apply for and obtain all other permits, licenses, and/or approvals from other agencies; i.e., local, state, and federal, which may have jurisdiction over the construction and/or operation of the source(s) and/or facility herein permitted.

2.6. Duty to Provide Information

The permittee shall furnish to the Secretary within a reasonable time any information the Secretary may request in writing to determine whether cause exists for administratively updating, modifying, revoking, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Secretary copies of records to be kept by the permittee. For information claimed to be confidential, the permittee shall furnish such records to the Secretary along with a claim of confidentiality in accordance with 45CSR31. If confidential information is to be sent to USEPA, the permittee shall directly provide such information to USEPA along with a claim of confidentiality in accordance with 40 C.F.R. Part 2.

2.7. Duty to Supplement and Correct Information

Upon becoming aware of a failure to submit any relevant facts or a submittal of incorrect information in any permit application, the permittee shall promptly submit to the Secretary such supplemental facts or corrected information.

2.8. Administrative Update

The permittee may request an administrative update to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-4.]

2.9. Permit Modification

The permittee may request a minor modification to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-5.4.]

2.10 Major Permit Modification

The permittee may request a major modification as defined in and according to the procedures specified in 45CSR14 or 45CSR19, as appropriate.
[45CSR§13-5.1]

2.11. Inspection and Entry

The permittee shall allow any authorized representative of the Secretary, upon the presentation of credentials and other documents as may be required by law, to perform the following:

a. At all reasonable times (including all times in which the facility is in operation) enter upon the permittee's premises where a source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect at reasonable times (including all times in which the facility is in operation) any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

d. Sample or monitor at reasonable times substances or parameters to determine compliance with the permit or applicable requirements or ascertain the amounts and types of air pollutants discharged.

2.12. Emergency

2.12.1. An "emergency" means any situation arising from sudden and reasonable unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

2.12.2. Effect of any emergency. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions of Section 2.12.3 are met.

2.12.3. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. An emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. The permitted facility was at the time being properly operated;

c. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

d. The permittee submitted notice of the emergency to the Secretary within one (1) working day of the time when emission limitations were exceeded due to the emergency and made a request for variance, and as applicable rules provide. This notice must contain a detailed description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

2.12.4. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.

2.12.5 The provisions of this section are in addition to any emergency or upset provision contained in any applicable requirement.

2.13. Need to Halt or Reduce Activity Not a Defense

It shall not be a defense for a permittee in an enforcement action that it should have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in determining penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continued operations.

2.14. Suspension of Activities

In the event the permittee should deem it necessary to suspend, for a period in excess of sixty (60) consecutive calendar days, the operations authorized by this permit, the permittee shall notify the Secretary, in writing, within two (2) calendar weeks of the passing of the sixtieth (60) day of the suspension period.

2.15. Property Rights

This permit does not convey any property rights of any sort or any exclusive privilege.

2.16. Severability

The provisions of this permit are severable and should any provision(s) be declared by a court of competent jurisdiction to be invalid or unenforceable, all other provisions shall remain in full force and effect.

2.17. Transferability

This permit is transferable in accordance with the requirements outlined in Section 10.1 of 45CSR13. **[45CSR§13-10.1.]**

2.18. Notification Requirements

The permittee shall notify the Secretary, in writing, no later than thirty (30) calendar days after the actual startup of the operations authorized under this permit.

2.19. Credible Evidence

Nothing in this permit shall alter or affect the ability of any person to establish compliance with, or a violation of, any applicable requirement through the use of credible evidence to the extent authorized by law. Nothing in this permit shall be construed to waive any defense otherwise available to the permittee including, but not limited to, any challenge to the credible evidence rule in the context of any future proceeding.

3.0. Facility-Wide Requirements

3.1. Limitations and Standards

3.1.1. **Open burning.** The open burning of refuse by any person, firm, corporation, association or public agency is prohibited except as noted in 45CSR§6-3.1.
[45CSR§6-3.1.]

3.1.2. **Open burning exemptions.** The exemptions listed in 45CSR§6-3.1 are subject to the following stipulation: Upon notification by the Secretary, no person shall cause, suffer, allow or permit any form of open burning during existing or predicted periods of atmospheric stagnation. Notification shall be made by such means as the Secretary may deem necessary and feasible.
[45CSR§6-3.2.]

3.1.3. **Asbestos.** The permittee is responsible for thoroughly inspecting the facility, or part of the facility, prior to commencement of demolition or renovation for the presence of asbestos and complying with 40 C.F.R. § 61.145, 40 C.F.R. § 61.148, and 40 C.F.R. § 61.150. The permittee, owner, or operator must notify the Secretary at least ten (10) working days prior to the commencement of any asbestos removal on the forms prescribed by the Secretary if the permittee is subject to the notification requirements of 40 C.F.R. § 61.145(b)(3)(i). The USEPA, the Division of Waste Management, and the Bureau for Public Health - Environmental Health require a copy of this notice to be sent to them.
[40CFR§61.145(b) and 45CSR§34]

3.1.4. **Odor.** No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor at any location occupied by the public.
[45CSR§4-3.1] ***[State Enforceable Only]***

3.1.5. **Permanent shutdown.** A source which has not operated at least 500 hours in one 12-month period within the previous five (5) year time period may be considered permanently shutdown, unless such source can provide to the Secretary, with reasonable specificity, information to the contrary. All permits may be modified or revoked and/or reapplication or application for new permits may be required for any source determined to be permanently shutdown.
[45CSR§13-10.5.]

3.1.6. **Standby plan for reducing emissions.** When requested by the Secretary, the permittee shall prepare standby plans for reducing the emissions of air pollutants in accordance with the objectives set forth in Tables I, II, and III of 45CSR11.
[45CSR§11-5.2.]

3.2. Monitoring Requirements

[Reserved]

3.3. Testing Requirements

3.3.1. **Stack testing.** As per provisions set forth in this permit or as otherwise required by the Secretary, in accordance with the West Virginia Code, underlying regulations, permits and orders, the permittee shall conduct test(s) to determine compliance with the emission limitations set forth in this permit and/or established or set forth in underlying documents. The Secretary, or his duly authorized representative, may at his option witness or conduct such test(s). Should the Secretary exercise his option to conduct such test(s), the operator shall provide all necessary sampling connections and sampling ports to be located in such manner as the Secretary may require, power for test equipment and the required safety equipment, such as scaffolding, railings and ladders, to comply with generally accepted good safety practices. Such tests shall be conducted in accordance with the methods and procedures set forth in this permit or as otherwise approved or specified by the Secretary in accordance with the following:

a. The Secretary may on a source-s-pecific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with 40 C.F.R. Parts 60, 61, and 63 in accordance with the Secretary's delegated authority and any established equivalency determination methods which are applicable. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.

b. The Secretary may on a source-specific- basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with applicable requirements which do not involve federal delegation. In specifying or approving such alternative testing to the test methods, the Secretary, to the extent possible, shall utilize the same equivalency criteria as would be used in approving such changes under Section 3.3.1.a. of this permit. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4. or 45CSR§13-5.4 as applicable.

c. All periodic tests to determine mass emission limits from or air pollutant concentrations in discharge stacks and such other tests as specified in this permit shall be conducted in accordance with an approved test protocol. Unless previously approved, such protocols shall be submitted to the Secretary in writing at least thirty (30) days prior to any testing and shall contain the information set forth by the Secretary. In addition, the permittee shall notify the Secretary at least fifteen (15) days prior to any testing so the Secretary may have the opportunity to observe such tests. This notification shall include the actual date and time during which the test will be conducted and, if appropriate, verification that the tests will fully conform to a referenced protocol previously approved by the Secretary.

d. The permittee shall submit a report of the results of the stack test within sixty (60) days of completion of the test. The test report shall provide the information necessary to document the objectives of the test and to determine whether proper procedures were used to accomplish these objectives. The report shall include the following: the certification described in paragraph 3.5.1.; a statement of compliance status, also signed by a responsible official; and, a summary of conditions which form the basis for the compliance status evaluation. The summary of conditions shall include the following:

   1. The permit or rule evaluated, with the citation number and language;
   2. The result of the test for each permit or rule condition; and,
   3. A statement of compliance or noncompliance with each permit or rule condition.

[WV Code § 22-5-4(a)(14-15) and 45CSR13]

3.4. Recordkeeping Requirements

3.4.1. **Retention of records.** The permittee shall maintain records of all information (including monitoring data, support information, reports, and notifications) required by this permit recorded in a form suitable and readily available for expeditious inspection and review. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation. The files shall be maintained for at least five (5) years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent two (2) years of data shall be maintained on site. The remaining three (3) years of data may be maintained off site, but must remain accessible within a reasonable time. Where appropriate, the permittee may maintain records electronically (on a computer, on computer floppy disks, CDs, DVDs, or magnetic tape disks), on microfilm, or on microfiche.

3.4.2. **Odors.** For the purposes of 45CSR4, the permittee shall maintain a record of all odor complaints received, any investigation performed in response to such a complaint, and any responsive action(s) taken.
[45CSR§4. *State Enforceable Only.*]

3.5. Reporting Requirements

3.5.1. **Responsible official.** Any application form, report, or compliance certification required by this permit to be submitted to the DAQ and/or USEPA shall contain a certification by the responsible official that states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

3.5.2. **Confidential information.** A permittee may request confidential treatment for the submission of reporting required by this permit pursuant to the limitations and procedures of W.Va. Code § 22-5-10 and 45CSR31.

3.5.3. **Correspondence.** All notices, requests, demands, submissions and other communications required or permitted to be made to the Secretary of DEP and/or USEPA shall be made in writing and shall be deemed to have been duly given when delivered by hand, or mailed first class or by private carrier with postage prepaid to the address(es), or submitted in electronic format by email as set forth below or to such other person or address as the Secretary of the Department of Environmental Protection may designate:

DAQ:
Director
WVDEP
Division of Air Quality
601 57th Street
Charleston, WV 25304-2345

US EPA:
Section Chief
U.S. Environmental Protection Agency, Region III
Enforcement and Compliance Assurance
Division Air Section (3ED21)
1650 Arch Street
Philadelphia, PA 19103-2029

DAQ Compliance and Enforcement[1]:
DEPAirQualityReports@wv.gov
[1]For all self-monitoring reports (MACT, GACT, NSPS, etc.), stack tests and protocols, Notice of Compliance Status Reports, Initial Notifications, etc.

3.5.4. Operating Fee

3.5.4.1. In accordance with 45CSR30 – Operating Permit Program, the permittee shall submit a certified emissions statement and pay fees on an annual basis in accordance with the submittal requirements of the Division of Air Quality. A receipt for the appropriate fee shall be maintained on the premises for which the receipt has been issued, and shall be made immediately available for inspection by the Secretary or his/her duly authorized representative.

3.5.5. **Emission inventory.** At such time(s) as the Secretary may designate, the permittee herein shall prepare and submit an emission inventory for the previous year, addressing the emissions from the facility and/or process(es) authorized herein, in accordance with the emission inventory submittal requirements of the Division of Air Quality. After the initial submittal, the Secretary may, based upon the type and quantity of the pollutants emitted, establish a frequency other than on an annual basis.

4.0. Source-Specific Requirements

4.1. Limitations and Standards

4.1.1. 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.

a. The following are the Level 1 CO_2 emissions limits for the corresponding Load Bins:

i. CO_2 emissions released while the electric steam generating unit (EGU) is operating greater than zero megawatt hour (MWh) (gross) to 313 MWh (gross), which shall be referred as Load Bin 0 (LB-0), shall have an initial bin limit not to exceed 9,864 pounds of CO_2 per MWh of gross electricity generation.

ii. CO_2 emissions released while the EGU is operating greater than 313 MWh (gross) up to 407 MWh (gross), which shall be referred as Load Bin 1 (LB-1), shall have an initial bin limit not to exceed 2,230 pounds of CO_2 per MWh of net electricity generation.

iii. CO_2 emissions released while the EGU is operating greater than 407 MWh (gross) up to 501 MWh (gross), which shall be referred as Load Bin 2 (LB-2), shall have an initial bin limit not to exceed 2,108 pounds of CO_2 per MWh of net electricity generation.

iv. CO_2 emissions released while the EGU is operating greater than 501 MWh (gross) up to 595 MWh (gross), which shall be referred as Load Bin 3 (LB-3), shall have an initial bin limit not to exceed 2,050 pounds of CO_2 per MWh of net electricity generation.

v. CO_2 emissions released while the EGU is operating greater than 595 MWh (gross) up to 689 MWh (gross), which shall be referred as Load Bin 4 (LB-4), shall have an initial bin limit not to exceed 2,002 pounds of CO_2 per MWh of net electricity generation.

vi. CO_2 emissions released while the EGU is operating greater than 689 MWh (gross), which shall be referred as Load Bin 5 (LB-5), shall have an initial bin limit not to exceed 1,958 pounds of CO_2 per MWh of net electricity generation.

b. At times when the unit has experienced an equipment failure that requires the unit to be operated at a higher heat rate (degraded efficiency), the Level 2 CO_2 Limits for Load Bins 1 through 5 shall be the Level 1 CO_2 Limits multiplied by 1.10 (ten percent above the Level 1 Limits) in accordance with the following requirements:

i. The permittee shall initially notify the Director in accordance with Condition 3.5.1. within 72-hours of experiencing such an event.

ii. Within 12 days of the initial notification, the permittee shall formally notify the Director whether or not the event will require the Level 2 CO_2 Limits be placed into effect. If so, the notification shall include a request for approval from the Director to operate under the Level 2 CO_2 Limits if the duration of the event is expected to last more than 180 days. This notification shall include the date and time when the unit commenced operations in a degraded efficiency mode, a justification that the Level 2 CO_2 Limits are required, and the expected duration of the Level 2 event. If the duration of the event is expected to end within 180 days of its commencement, the operation under the Level 2 CO_2 Limits shall be deemed approved unless the permittee is notified by the Director within fifteen (15) days of the formal notification that the event does not qualify as a Level 2 event. If the duration of the event is expected to last more than 180 days, the Director shall notify the permittee within 30 days on whether or not the event qualifies as a Level 2 event and thereby being approved or disapproved.

iii. Within thirty days after the confirmed commencement of an event requiring Level 2 CO_2 Limits, the permittee shall develop and submit a corrective action plan to the Director. Within the plan, the permittee must identify the defective component/piece of equipment, identify repairs necessary to restore the unit's performance, and project the duration that the Level 2 Limits will be in effect. Such plan must identify milestones of critical tasks; identify resources needed for the repair(s) to include labor, materials, and special equipment; and include a projected timeline of restoring the unit. The permittee, upon request, may extend the projected duration with written approval by the Director. No individual period that the Level 2 CO_2 Limits are in affect shall extend beyond 24 months.

iv. The permittee shall submit reports of the status of the corrective action plan at least once every two months. These reports shall include the number of hours the unit has operated in Load Bin 1 through 5 during the period, the average net heat rate of the unit, and the average CO_2 emission rate in lb/MWh net for the period.

v. Within fifteen (15) days of restoring the unit's efficiency, the permittee shall notify the director that the Level 2 CO_2 Limits are no longer being utilized and that the unit has reverted back to the Level 1 CO_2 Limits. Within ninety (90) days of restoring the unit's efficiency, the permittee shall prepare a Root Cause Analysis (RCA) report of the event. The report shall identify the cause, identify corrective actions to prevent future failure(s) and/or measures to reduce the duration to complete repair for Level 2 CO_2 Limits durations that extend beyond six months. The report shall note total number of hours the unit has operated in Load Bins 1 through 5 during the period, the average net heat rate of the unit, and the average CO_2 emission rate in lb/MWh net for the period. In the event that a RCA may not be finalized within the 90 day period, a schedule shall be submitted detailing the reason(s) for non-completion as well as a timeline for completion.

vi. The Level 2 CO_2 Limit does not apply to an event that causes a forced unit outage in which all repairs necessary to restart the unit may be completed immediately and renders the unit capable of achieving the Level 1 CO_2 Limit. In accordance with Condition 2.12., if repairs that would restore the unit to the Level 1 CO_2 Limit performance are not feasibly achievable, the Level 2 CO_2 Limit may be utilized by following the procedures in Condition 4.1.1.b.

All notifications and reports stipulated in Condition 4.1.1.b shall be submitted in accordance with Condition 3.5.3. and records of such submissions shall be maintained in accordance with Condition 3.4.1.

c. Unit degradation adjustment Factor (UDAF) - After the initial compliance period, the CO_2 limit for each of the load bins in Condition 4.1.1.a. shall be adjusted (increased) annually by 0.4%. Once every five years after the initial compliance period, a recovery (decreased) percentage of 0.7% shall be applied to the individual CO_2load bin limits. The 0.7% recovery shall be applied to the most recent CO_2 limits adjusted by the annual 0.4% UDAF. The UDAF shall be applied up to and including calendar year 2046. Beginning with calendar year 2047, the UDAF shall no longer be applied and the CO_2 Load Bin limits shall remain at the 2046 levels.

d. Coal adjustment factor (CAF) shall be applied to the Level 1 and Level 2 CO_2 Limits with the appropriate UDAF applied limits. The CAF shall be the ratio of future CO_2 emissions divided by the baseline CO_2 emissions as determined in accordance with Condition 4.3.1.

The CAF is only applicable when the permittee requires a fuel switch that results in the different source of coal that the permittee 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, will increase or decrease 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.

4.1.2. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, maintain, and operate all pollution control equipment listed in Section 1.0 and associated monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions, or comply with any more stringent limits set forth in this permit or as set forth by any State rule, Federal regulation, or alternative control plan approved by the Secretary.
[45CSR§13-5.10.]

4.2. Monitoring Requirements

4.2.1. The permittee must determine the hourly CO_2 mass emissions in pounds from the emission point EA1 according to the following paragraphs.

a. The permittee shall install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR §75.10(a)(3)(i). If the permittee measures CO_2 concentration on a dry basis, the permittee must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR §75.11(b).

b. For each continuous monitoring system that the permittee uses to determine the CO_2 mass emissions, the permittee must meet the applicable certification and quality assurance procedures in 40 CFR §75.20 and appendices A and B to 40 CFR Part 75.

c. The permittee must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; the permittee must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR Part 75 to the exhaust gas flow rate data.

d. The permittee must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR Part 75. If the permittee uses a Type-S pitot tube or a pitot tube assembly for the flow RATAs, the permittee must calibrate the pitot tube or pitot tube assembly. The permittee may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2 in appendix A to 40 CFR Part 60.

e. Calculate the hourly CO_2 mass emissions (lb) as described in Condition 4.2.1.(e)(i) through (iii) of this section. Perform this calculation only for “valid operating hours”, as defined in 40 CFR §60.5540(a)(1).

i. Begin with the hourly CO_2 mass emission rate (pounds/hr), obtained either from Equation F-11 in appendix F to 40 CFR Part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to 40 CFR Part 75 (if CO_2 concentration is measured on a dry basis).

ii. Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR §72.2), to convert it to tons of CO_2.

iii. The hourly CO_2 (pounds/hr) values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR §75.57(e) and must be reported electronically under 40 CFR §75.64(a)(6). The permittee must use these data to calculate the hourly CO_2 mass emissions.

f. The permittee shall record the length of time that the EGU operated within each load bin as defined in Condition 4.1.1. a through b.

g. The permittee shall maintain records of maintenance performed, calibrations, performance evaluations, and CEMS data in accordance with Condition 3.4.1.

4.2.2. The permittee must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross and net electric output, as applicable, from the permitted EGU. These instruments must use 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20 (incorporated by reference, see 40 CFR §60.17). The permittee shall maintain records of maintenance performed, calibrations, performance evaluations, and data within a data collection system in accordance with Condition 3.4.1.

4.2.3. The permittee shall maintain and operate a system that measures, records operational data of the EGU and calculates the unit heat rate in terms of Btu per kilowatt-hour based on using a Rankine cycle model of the permitted unit in accordance with latest version of the American Society of Mechanical Engineers (ASME) Performance Test Code Performance Monitoring Guidelines for Power Plant (ASME PTC PM-2010) or future test method developed by ASME to measure the heat rate from power plant. Records of the calculated heat rate reduced to hourly values and maintenance performed on the system shall be maintained in accordance with Condition 3.4.1.

4.2.4. The permittee shall evaluate the data as required to be collected under Condition 4.2.1. to determine if the data is “valid data” using the criteria set forth in this condition. Each compliance period shall include only “valid operating hours” in the compliance period, i.e., operating hours for which:

a. “Valid data” is defined as quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to 40 CFR Part 75. For CEMS, the initial certification requirements in 40 CFR §75.20 and appendix A to 40 CFR Part 75 must be met before quality-assured data are reported under this permit. For on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to 40 CFR Part 75 must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to 40 CFR Part 75 apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to 40 CFR Part 75 must be met before quality-assured data are reported under this permit, and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to 40 CFR Part 75 apply.

b. "Valid data" are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (lb) and,

c. The corresponding hourly net energy output value is also valid data (Note: For hours with no useful output, zero is considered to be a valid value).

d. The permittee must exclude operating hours in which:

i. The substitute data provisions of 40 CFR Part 75 are applied for any of the parameters used to determine the hourly CO_2 mass emissions; or

ii. An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

iii. The total net energy output is unavailable.

e. For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph a of this condition.

i. At times when the CEMS CO_2 emission data falls below the above 95% threshold during the compliance period, the permittee shall use the procedures from Appendix G to 40 CFR Part 75 to determine the CO_2 emissions for the periods when CO_2 emissions data is missing.

f. The permittee must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from monitored data collected under Condition 4.2.1. for all the valid operating hours for each month within the compliance period.

4.3. Testing Requirements

4.3.1. Within 90 days prior to conducting a fuel switch that the permittee has determined an adjustment to the CO_2 limit is needed, the permittee shall conduct emission testing to establish the CAF to be applied to the CO_2 limit. Such testing shall be conducted by an independent third-party to establish the following:

a. Establish baseline of CO_2 emissions of the current coal utilized with the unit operating in Load Bin 5 for at least 90% of the operating hours during a consecutive operating period of no less than 7 operating days.

i. Determine the CO_2 emissions of the future coal with the unit operating in Load Bin 5 for at least 90% of the operating hours during a consecutive operating period of no less than 7 operating days.

ii. The standard deviation of the CO_2 emissions data used in the ratio to develop the CAF for each of the two phases (baseline and future coal) of testing must not be greater than 68 lb/MWh-net.

iii. Determine the Net Hourly Heat Rate of the unit during all phases of testing.

b. Prior to conducting the testing of the future coal source, the permittee shall tune the unit to the future coal source for optimum performance while operating in Load Bin 5 using manual operation and intelligent combustion-controlled operation. The process of tuning the unit shall include three phases, manual control, hybrid between manual and intelligent combustion control operation, and intelligent combustion-controlled operation. The timing for this tuning phase shall not exceeded 30 days.

c. The protocol must include the following:

   i. The protocol must provide justification that the CO_2 limits will be affected by utilizing the future source of coal. At a minimum, such justification shall identify how the new source of fuel differs in characteristics from the existing source in terms of heating value, sulfur, and ash content and how these and other different characteristics will influence heat rate and compliance with CO_2 limits. Such justification may include but not be limited to evaluations of impact on CO_2 emissions using alternative procedures in Appendix G of 40 CFR Part 75 or other third party coal quality analysis programs that determine the unit performance output due to fuel quality.

   ii. The protocol must outline how the unit will be tuned to the future source of coal and how the third-party firm will be determining/evaluating that the unit has been optimized to the future source of coal. The protocol must provide duration for tuning and what parameter(s) will be evaluated to determine if the unit has been optimized.

   iii. The protocol must outline any contingency plans for extending the testing to meeting the emission data quality requirements and procedures for notifying the Director when implementing it.

   iv. Procedures for collecting, processing, reviewing and evaluating the emissions data.

   v. The protocol must identify the third-party and roles that the third-party will take overseeing the tuning of the unit, emission testing, and evaluation of the data collected.

   vi. The protocol must identify the credentials and qualification of the third-party overseeing this testing.

   vii. The protocol must conform to the testing requirements of Condition 3.3.1.

d. Within 60 days of completion of these tests, the permittee shall develop a test report which shall include the following:

   i. Hourly CO_2 emissions data of the baseline and future coal runs.

   ii. Hourly Heat Rate of the unit during the testing.

   iii. Readings of the unit parameters proposed to be used to determine when the unit is optimized on the future coal during the tuning and testing phases.

   iv. Evaluation of the emissions data collected during the baseline and future coal runs of the testing.

   v. Determination that the CAF of the proposed future coal is necessary.

   vi. Determination of the CAF to be applied to the CO_2 Limits for Load Bins 0 through 5 for this future coal source if applicable.

   vii. List the adjusted CO_2 limits for Load Bins 0 through 5 with the CAF applied.

   viii. List the date and time of when the unit continuously utilizes the new coal source.

e. Records of the testing, protocol, and results shall be maintained in accordance with Condition 3.3.1.

4.4. Recordkeeping Requirements

4.4.1. **Record of Monitoring.** The permittee shall keep records of monitoring information that include the following:

a. The date, place as defined in this permit, and time of sampling or measurements;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of the analyses; and

f. The operating conditions existing at the time of sampling or measurement.

4.4.2. **Record of Maintenance of Air Pollution Control Equipment.** For all pollution control equipment listed in Section 1.0, the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures.

4.4.3. **Record of Malfunctions of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0, the permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment during which excess emissions occur. For each such case, the following information shall be recorded:

a. The equipment involved.

b. Steps taken to minimize emissions during the event.

c. The duration of the event.

d. The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

e. The cause of the malfunction.

f. Steps taken to correct the malfunction.

g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.

4.4.4. Except for the limit for LB-0 in condition 4.1.1.a.i., the permittee shall determine the CO_2Weighted Average Limit for each calendar year in accordance with the following:

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

$\sum OPHL1_{LB-1}$ = Total Level 1 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)

$\sum OPHL1_{LB-2}$ = Total Level 1 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)

$\sum OPHL1_{LB-3}$ = Total Level 1 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)

$\sum OPHL1_{LB-4}$ = Total Level 1 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)

$\sum OPHL1_{LB-5}$ = Total Level 1 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)

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

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 in Condition 4.1.1.a.

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)

For times when a CAF is applied after the beginning of a compliance period, the permittee shall determine the Level 1 *CO_2 weighted avg* and Level 2 *CO_2 weighted avg* for the before the CAF and after the CAF using Equations 1 and 2 and the appropriate CO_2 limits for each of the load bins. The permittee shall use the following equation to determine the *CO_2 weighted avg* in lieu of Equation 3.

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.

$\sum OPHL2_{BCAF}$ = 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.

$\sum OPHL1_{ACAF}$ = 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.

Should the Administrator promulgate a revised CO_2 emission standard for new, modified, or reconstructed coal-fired EGUs under Subpart TTTT of 40 CFR 60 that are less stringent than the limitations in this permit, then the permittee is required to demonstrate compliance for that respective year to the revised Subpart TTTT standard. Should the revised Subpart TTTT standard be in terms that differ from the limit in this permit, the Director shall review and approve any method used to convert the limits into common terms.
[W.Va. Code §22-5-4(a)(4)]

Records of all calculations shall include the CO_2 weighted average limit and shall be maintained in accordance with Condition 3.4.1

4.4.5. Compliance Demonstrations: The initial compliance period shall begin on January 1, 2021 and end on December 31, 2021. Subsequent compliance periods shall follow thereafter. The compliance demonstration shall be performed no later than March 1 after the compliance period.

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.

Excluding CO_2 rates and generation that occurred while the unit was operating in Load Bin 0, the permittee shall conduct a compliance demonstration with the CO_2 Weighted Average limit as calculated from either Equation 3 or 4 in Condition 4.4.4. The compliance demonstration shall be determined by taking the sum of the valid hourly CO_2 rates in terms of lb divided by the sum of the net electricity generation (MWh net) in the respective compliance period for Load Bins 1 through 5. Excess CO_2 emissions is the amount of the actual annual average CO_2 rate above the CO_2 weighted average limit, if any.

Records of all demonstrations shall include actual annual average CO_2 rate and excess CO_2 emissions and shall be maintained in accordance with Condition 3.4.1.

4.4.6. The permittee shall maintain the following records:

a. Monitoring plan records under 40 CFR §75.53(g) and (h);

b. Operating parameter records under 40 CFR §75.57(b)(1) through (4).

c. The records under 40 CFR §75.57(c)(2), for stack gas volumetric flow rate;

d. The records under 40 CFR §75.57(c)(3) for continuous moisture monitoring systems;

e. The records under 40 CFR §75.57(e)(1), except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems;

f. The records under 40 CFR §75.58(c)(4), specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

g. The quality-assurance records under 40 CFR §75.59(a), specifically paragraphs (a)(1) through (12) and (15), for CEMS;

h. Records of data acquisition and handling system (DAHS) verification under 40 CFR §75.59(e).

i. Records of the calculations performed to determine the hourly and total CO_2 mass emissions (tons) for:

   i. Each operating month; and

   ii. Each compliance period, including, each 12-operating-month compliance period.

j. Records of the applicable data recorded, and calculations performed that are used to determine the EGU's net energy output for each operating month.

k. Records of the calculations performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

l. Records of the calculations performed to determine the weighted average CO_2 limits.

These records shall be maintained in accordance with Condition 3.4.1.

4.5. Reporting Requirements

4.5.1. The permittee shall prepare and submit an Annual Compliance report to the Director in accordance with Condition 3.5.3. by no later than March 1 following the end of each compliance period. Such report shall include the following and be certified by a responsible official.

a. The CO_2 Weighted Limits, Level 1 CO_2 Weighted Limits and the Level 2 CO_2 Weighted Limits, when applicable, as determined from Equations 1, 2 and 3 in Condition 4.4.4.

b. The current and next compliance period CO_2 Limit for each load bin adjusted in accordance with unit degradation adjustment factor provisions of Condition 4.1.1.c. and coal adjustment factor of Condition 4.1.1.d. when applicable.

c. The actual CO_2 rate of Load Bins 1 through 5 in terms of the limit for the compliance period.

d. The actual CO_2 rate of Load Bin 0 during the compliance period.

e. Excess emissions if any.

f. The percentage of valid operating hours during the compliance period.

g. The number of operating hours for each load bin as defined in Condition 4.1.1. during the compliance period.

h. The net energy output during the compliance period excluding operations occurring in Load Bin 0.

i. The gross energy output during the compliance period for Load Bin 0.

j. The annual average heat rate.

Records of such reports shall be maintained in accordance with Condition 3.4.1.

4.5.2. The permittee shall submit reports as required under Subpart G of 40 CFR Part 75 that are applicable to the permitted facility.

CERTIFICATION OF DATA ACCURACY

I, the undersigned, hereby certify that, based on information and belief formed after reasonable inquiry, all information contained in the attached ___________________________________, representing the period beginning ________________________ and ending ________________________, and any supporting documents appended hereto, is true, accurate, and complete.

Signature[1] ____ ____________________
(please use blue ink) Responsible Official or Authorized Representative Date

Name & Title __________________________________ __________________________________
(please print or type) Name Title

Telephone No. _______________________________ Fax No. _______________________________

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[1] This form shall be signed by a "Responsible Official." "Responsible Official" means one of the following:

a. For a corporation: The president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

   (i) the facilities employ more than 250 persons or have a gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or

   (ii) the delegation of authority to such representative is approved in advance by the Director;

b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

c. For a municipality, State, Federal, or other public entity: either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of U.S. EPA); or

d. The designated representative delegated with such authority and approved in advance by the Director.

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Other Administrative Records for Permit R13-3495

All other administrative records pertaining to the development of the Longview Power Permit R13-3495 that was issued December 23, 2020 may be obtained from DEP's electronic document management system using the link and the instructions provided below.

To view permitting actions via the DEP's electronic document management system, use the link and instructions below:

Go to: https://documents.dep.wv.gov/appxtender *(works best with Microsoft Edge or Google Chrome)*
User Name = DEP
Password = DEP

1. Double-click on PERMITSAIR from the applications listed on the left pane. It should turn blue when selected.
2. Click on the blue square NEW QUERY.
3. In the SECONDARY ID NUMBER box, enter the permit number listed above (for example, 13-3495). Click the RUN button at the bottom of the page. You may sort any of the columns by clicking the column heading.
4. Double-click the document in the QUERY RESULTS you want to view.