January 8, 2020

Philip Antici
Manager, HSES
FutureFuel Chemical Company (FutureFuel)

Sent via Electronic Mail

RE: Regional Haze Four-Factor Analysis; Information Collection Request; AFIN 32-00036

Dear Mr. Antici:

The Arkansas Department of Energy and Environment, Division of Environmental Quality (DEQ) hereby requests that FutureFuel submit the information described in Section II no later than 90 days from the date of this letter.

I. BACKGROUND

DEQ must develop a Regional Haze Program state implementation plan (SIP) that demonstrates reasonable progress toward achieving natural visibility conditions in Arkansas Class I areas during the period between 2018 and 2028, which is referred to as Planning Period II. The SIP must also address emissions from within the state that may impair visibility in Class I areas in other states. The Regional Haze Program uses an iterative planning process lead by the states with the ultimate goal of remedying existing and preventing future visibility impairment from anthropogenic sources of air pollution by 2064.

For the Planning Period II SIP, DEQ must develop a long-term strategy for reducing emissions of key pollutants and sources impacting visibility at Class I areas to make "reasonable" progress toward the goal of no anthropogenic visibility impairment by 2064. The Regional Haze Rule provides four factors by which a state must consider potential control measures for the long-term strategy. The factors are the cost of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of existing sources that contribute to visibility impairment.

The key pollutants from anthropogenic sources impairing visibility at Arkansas Class I areas are ammonium sulfate and ammonium nitrate.[1] Ammonium sulfate is formed by chemical reactions between ammonia and sulfur dioxide (SO_2) in the atmosphere. Ammonium nitrate is formed by chemical reactions between ammonia and nitrogen oxides (NOx) in the atmosphere. EPA modeling projects that these two pollutants will continue to be the key pollutants contributing to visibility impairment at Arkansas Class I areas in 2028.[2]

The states in the Central States Air Resources Agencies (CENSARA) organization, which includes Arkansas, contracted with Ramboll US Corporation (Ramboll) to produce a study examining the impact of stationary sources of NOx and SO_2 on each Class I area in the central region of the United States. For each Class I area, the study took into account light extinction-weighted wind trajectory residence times, 2016 sulfur dioxide and nitrogen oxides facility emissions, and distance from sources of nitrogen oxides and sulfur dioxide to Class I Areas. The study produced an area of influence (AOI) for each Class I area, which shows the geographic areas with a high probability of contributing to anthropogenic visibility impairment.

Based on the results of the AOI study, DEQ has identified FutureFuel as a source of visibility impacting pollutant emissions that DEQ should evaluate for potential emission reduction measures during Planning Period II.

II. INFORMATION REQUESTED FOR POTENTIAL EMISSION REDUCTION STRATEGIES

DEQ requests that FutureFuel provide information about potential emission reduction strategies for SO_2 and NOx emissions from the FutureFuel facility. At a minimum, FutureFuel should include the following potential strategies for the emission units that emit the majority of the SO_2 and NOx from FutureFuel, identified by DEQ as SN:6M01-01 three coal-fired boilers:

- SO_2 (ranked from highest control efficiency to lowest)
  - Fuel switching from subbituminous coal to natural gas (Typical SO_2 control efficiency ≈ 99.9%)[3]
  - Wet Gas Scrubber[4] (Typical SO_2 control efficiency for industrial coal-fired boilers ≈ 90–99%)

[1] http://vista.cira.colostate.edu/Improve/improve-data/

[2] https://www.epa.gov/visibility/visibility-guidance-documents

[3] From EPA Menu of Control Measures: "Fuel substitution involves replacing the current fuel with a fuel which emits less of a given pollutant when burned. For many older boilers, fuel switching is an especially attractive option because the capital investment is usually small when compared to that of control devices. Cost effectiveness varies depending on the ranks of the old and new fuels and is estimated based on the emission factors."

[4] From EPA Menu of Control Measures: "Wet scrubbing techniques are used to control both particulate and SO2 emissions. Wet scrubbing processes used to control SO2 are generally termed flue-gas desulfurization (FGD) processes. FGD utilizes gas absorption technology, the selective transfer of materials from a gas to a contacting liquid, to remove SO2 in the waste gas. Caustic, crushed limestone, or lime are used as scrubbing agents. Cost estimates are from the OTC / LADCO Workgroup (OTC / LADCO Control Cost Subgroup), for a 66% capacity factor at 8760 hour/year, and are based on a methodology similar to EPA's methodology provided in the EPA

- Spray Dryer Absorber[5] (Typical SO_2 control efficiency for industrial coal-fired boilers ≈ 90–95%)
- In-Duct Dry Sorbent Injection[6] (Typical SO_2 control efficiency for industrial coal-fired boilers ≈ 40%)
- Fuel Switching to lower sulfur coal (Typical control efficiency proportionate to the % decrease in sulfur content)

- NOx (ranked from typical highest control efficiency to lowest)
  - Selective Catalytic Reduction[7] (Typical NOx control efficiency for industrial coal-fired boilers ≈ 80%)
  - Low NOx Burner[8] (Typical NOx control efficiency for industrial coal-fired boilers ≈ 50%)
  - Selective Non-Catalytic Reduction[9] (Typical NOx control efficiency for industrial coal-fired boilers ≈ 40%)

The list above is not comprehensive. FutureFuel may provide information about strategies in addition to those listed above.

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document "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers"'.

[5] From EPA Menu of Control Measures: "Spray dryer absorption (SDA) systems spray lime slurry into an absorption tower where SO2 is absorbed by the slurry, forming CaSO3/CaSO4. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are carried out with the gas and collected with a fabric filter or ESP. When used to specifically control SO2, the term dry flue-gas desulfurization (dry FGD) may also be used. Cost estimates are from the OTC / LADCO Workgroup (OTC / LADCO Control Cost Subgroup), for a 66% capacity factor at 8760 hour/year, and are based on a methodology similar to EPA's methodology provided in the EPA document "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers"'.

[6] From EPA Menu of Control Measures: "As opposed to spray dryer absorption, in duct sorbent injection technology does not require a dedicated reactor and instead uses the existing boiler and duct system as the "reactor," and several configurations are possible based on the temperature window desired. DSI technologies include calcium (lime) and sodium (trona) reagents and are currently being tested or demonstrated within the ICI boiler sector."

[7] From EPA Menu of Control Measures: "This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to coal ICI boilers with NOx emissions greater than 10 tons per year."

[8] From EPA Menu of Control Measures: "This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to coal/wall fired ICI boilers and Petroleum coke fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year. Cost estimates are from the OTC / LADCO Workgroup (OTC / LADCO Control Cost Subgroup), for a single burner (for a 66% capacity factor at 8760 hours/year), and are based on a methodology similar to EPA's methodology provided in the EPA document "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers"'.

[9] From EPA Menu of Control Measures: "This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to coal IC boilers with uncontrolled NOx emissions greater than 10 tons per year."

For each emission reduction strategy, FutureFuel should assess whether the strategy is technically feasible.[10] If a strategy is not technically feasible, FutureFuel should provide a robust explanation about why the strategy is not technically feasible.

For each technically feasible emission reduction strategy, FutureFuel should provide the following information for SO_2 and/or NOx:

- Control effectiveness (Percentage NOx and/or SO_2 reduced) estimates specific to FutureFuel's emission units in terms of actual emissions
- Emission reductions that would be achieved by implementation of the strategy:
    - Baseline actual emission rate in lb/hr or lb/MMBTU (maximum monthly value in the period between 2017–2019)
    - Control rate in lb/hr or lb/MMBTU (units should match baseline actual emission rate)
    - Resulting annual emission reductions (tons/year)
- Time necessary to implement the strategy with an explanation justifying the time needed
    - A reasonable time period is one in which the source comes "into compliance in an efficient manner without unusual amounts of overtime, above-market wages and prices, or premium charges for expedited delivery of control equipment."[11]
    - The time during which the source begins taking steps to come into compliance is assumed to begin upon EPA approval of the SIP, which is projected to be no later than January 31, 2023 based on deadlines for the SIP submission and EPA action on the SIP.[12]
- Remaining useful life
    - Remaining useful life of an emission unit should be based on an enforceable shutdown date. Otherwise, the remaining useful life should be the full period of the useful life for the control technology evaluated
    - The EPA Pollution Control Cost Manual[13] provides guidance on typical values for the useful life of various emission control systems
- Energy and non-air quality environmental impacts

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[10] From 40 CFR Appendix Y to Part 51 "Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: 'availability' and 'applicability.' As explained in more detail below, a technology is considered 'available' if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is 'applicable' if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible."

[11] https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period

[12] The deadline for submission of this state implementation plan is July 31, 2021. EPA's deadlines for timely action on a SIP submittal are as follows: six months for determining whether a SIP is complete and one year from determining that a SIP is complete to take final action on the SIP.

[13] https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

- Specify any energy and non-air environmental impacts, such as the generation of wastes for disposal, impacts on other environmental media, etc.
- Factor any costs associated with energy and non-air environmental impacts into the cost of implementing the strategy, including without limitation:
  - Permitting costs if other regulatory requirements are triggered by the strategy
  - Costs associated with compliance with any other regulatory requirements triggered by the strategy
  - Cost of waste disposal for wastes generated by proposed control systems
  - Changes associated with alternative disposal methods for chemical waste currently burned in coal-fired boilers

- Cost of implementing the strategy
  - Use the EPA Pollution Control Cost Control Cost Manual[14] overnight methodology to quantify the following cost metrics:
    - Capital costs
    - Annual operating and maintenance costs
    - Annualized costs
  - The amortization period should be based on the time between when the strategy could reasonably be in place and the remaining useful life of the emission unit or emission control system, whichever is less.[15]

III. CONCLUSION

Thank you for your timely response to this information request. This information is necessary for DEQ to prepare a technically and legally robust state implementation plan consistent with the Regional Haze Rule. Please respond with the requested information by April 7, 2020. If you have any questions, please contact Tricia Treece (treecep@adeq.state.ar.us) of my staff.

Sincerely,

William K. Montgomery
Interim Associate Director
Office of Air Quality
Division of Environmental Quality
Arkansas Department of Energy and Environment

[14] https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[15] Amortization start date is equal to the time necessary for compliance for the strategy added to January 31, 2023 (Deadline for timely EPA action on a SIP submitted on July 31, 2021).

CC:

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Farah Robbins, FutureFuel Chemical Company