ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R05–OAR–2010–0954; EPA–R05–OAR–2010–0037; FRL–9709–8]

Approval and Promulgation of Implementation Plans; States of Minnesota and Michigan; Regional Haze Federal Implementation Plan

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing a Federal Implementation Plan (FIP) to address the requirement for best available retrofit technology (BART) for taconite plants in Minnesota and Michigan. BART is a requirement of EPA's regional haze rule which has not been satisfied by Minnesota or Michigan for its subject taconite plants. EPA developed this proposal in response to an inadequate BART determination by Michigan for its one subject taconite source. On June 12, 2012, EPA approved revisions to the Minnesota State Implementation Plan (SIP) addressing regional haze but also, on that date, announced that in response to comments it was deferring action on emission limitations that Minnesota intended to represent BART for its taconite facilities. EPA is proposing to determine that the FIP satisfies requirements of the Clean Air Act (CAA or "the Act") that require states, or EPA in promulgating a FIP, to establish BART for applicable sources.

DATES: Comments must be received on or before September 28, 2012.

Public Hearing. EPA will hold a public hearing to solicit comments on its proposal to establish emission limits for taconite plants in Minnesota and Michigan, to satisfy requirements for best available retrofit technology for these facilities. This hearing will be held on Wednesday, August 29, 2012, 10 a.m. to 2 p.m., Office of Minnesota Pollution Control Agency, 520 Lafayette Road, St. Paul, MN, Citizens Board Hearing Room. Information on this hearing is also available at *http://www.epa.gov/region5/mnhaze.*

ADDRESSES: Submit your comments, identified by Docket ID Nos. EPA–R05–OAR–2010–0954 and EPA–R05–OAR–2010–0037, by one of the following methods:

1. *www.regulations.gov:* Follow the on-line instructions for submitting comments.
2. *Email: aburano.douglas@epa.gov.*
3. *Fax:* (312) 408–2279.
4. *Mail:* Douglas Aburano, Chief, Attainment Planning and Maintenance Section, Air Programs Branch (AR–18J), U.S. Environmental Protection Agency, 77 West Jackson Boulevard, Chicago, Illinois 60604.
5. *Hand Delivery:* Douglas Aburano, Chief, Attainment Planning and Maintenance Section, Air Programs Branch (AR–18J), U.S. Environmental Protection Agency, 77 West Jackson Boulevard, Chicago, Illinois 60604. Such deliveries are only accepted during the Regional Office normal hours of operation, and special arrangements should be made for deliveries of boxed information. The Regional Office official hours of business are Monday through Friday, 8:30 a.m. to 4:30 p.m., excluding Federal holidays.

Instructions: Direct your comments to Docket ID Nos. EPA–R05–OAR–2010–0954 and EPA–R05–OAR–2010–0037. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or email. The *www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to EPA without going through *www.regulations.gov* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional instructions on submitting comments, go to Section I of the **SUPPLEMENTARY INFORMATION** section of this document.

Docket: All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Environmental Protection Agency, Region 5, Air and Radiation Division, 77 West Jackson Boulevard, Chicago, Illinois 60604. This facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding federal holidays. We recommend that you telephone Steven Rosenthal at (312) 886–6052 before visiting the Region 5 office.

FOR FURTHER INFORMATION CONTACT:
Steven Rosenthal, Environmental Engineer, Attainment Planning & Maintenance Section, Air Programs Branch (AR–18J), U.S. Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604, (312) 886–6052, *rosenthal.steven@epa.gov.*

SUPPLEMENTARY INFORMATION:
Throughout this document whenever "we," "us," or "our" is used, we mean EPA. This supplementary information section is arranged as follows:

I. What should I consider as I prepare my comments for EPA?

When submitting comments, remember to:

1. Identify the rulemaking by docket number and other identifying information (subject heading, **Federal Register** date, and page number).
2. Follow directions—The EPA may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.
3. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.
4. Describe any assumptions and provide any technical information and/or data that you used.
5. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.
6. Provide specific examples to illustrate your concerns, and suggest alternatives.
7. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

8. Make sure to submit your comments by the comment period deadline identified.

II. What action is EPA taking today?

EPA is proposing a FIP that establishes BART emission limitations for the taconite plants in Minnesota and Michigan that are subject to the Regional Haze Rule.

III. Background

A. Regional Haze

Regional haze is visibility impairment that is produced by a multitude of sources and activities which are located across a broad geographic area and emit fine particulates ($PM_{2.5}$) (*e.g.,* sulfates, nitrates, organic carbon (OC), elemental carbon (EC), and soil dust), and their precursors (*e.g.,* sulfur dioxide (SO_2), nitrogen oxides (NO_X)). Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that one can see. $PM_{2.5}$ can also cause serious health effects and mortality in humans and contributes to environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the ''Interagency Monitoring of Protected Visual Environments'' (IMPROVE) monitoring network, show that visibility impairment caused by air pollution occurs virtually all the time at most national park and wilderness areas. The average visual range [1] in many Class I areas (*i.e.,* NPs and memorial parks, WA, and international parks meeting certain size criteria) in the western United States is 100–150 kilometers, or about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. In most of the eastern Class I areas of the United States, the average visual range is less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions. 64 FR 35715 (July 1, 1999).

B. Requirements of the CAA and EPA's Regional Haze Rule

In section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the ''prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas [2] which impairment results from manmade air pollution.'' On December 2, 1980, EPA promulgated regulations to address visibility impairment in Class I areas that is ''reasonably attributable'' to a single source or small group of sources, *i.e.,* ''reasonably attributable visibility impairment.'' (45 FR 80084, December 2, 1980). These regulations represented the first phase in addressing visibility impairment. EPA deferred action on regional haze that emanates from a variety of sources until monitoring, modeling and scientific knowledge about the relationships between pollutants and visibility impairment were improved.

Congress added section 169B to the CAA in 1990 to address regional haze issues. EPA promulgated a rule to address regional haze on July 1, 1999. (64 FR 35714, July 1, 1999), codified at 40 CFR part 51, subpart P. The Regional Haze Rule revised the existing visibility regulations to integrate into the regulation provisions addressing regional haze impairment and established a comprehensive visibility protection program for Class I areas. The requirements for regional haze, found at 40 CFR 51.308 and 51.309, are included in EPA's visibility protection regulations at 40 CFR 51.300–309. Some of the main elements of the regional haze requirements are summarized in this section of this preamble. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia and the Virgin Islands.[3] 40 CFR 51.308(b) requires states to submit the first implementation plan addressing regional haze visibility impairment no later than December 17, 2007.[4]

Few states submitted a Regional Haze SIP prior to the December 17, 2007 deadline, and on January 15, 2009, EPA found that 37 states, including Michigan and Minnesota, had failed to submit SIPs addressing the regional haze requirements. (74 FR 2392, January 15, 2009). Once EPA has found that a state has failed to make a required submission, EPA is required to promulgate a FIP within two years unless the state submits a SIP and the Agency approves it within the two year period. CAA § 110(c)(1).

C. Roles of Agencies in Addressing Regional Haze

Successful implementation of the regional haze program will require long-term regional coordination among states, tribal governments and various federal agencies. As noted above, pollution affecting the air quality in Class I areas can be transported over long distances, even hundreds of kilometers. Therefore, to effectively address the problem of visibility impairment in Class I areas, states, or the EPA when implementing a FIP, need to develop strategies in coordination with one another, taking into account the effect of emissions from one jurisdiction on the air quality in another.

Because the pollutants that lead to regional haze can originate from sources located across broad geographic areas, EPA has encouraged the states and tribes across the United States to address visibility impairment from a regional perspective. Five regional planning organizations (RPOs) were developed to address regional haze and related issues. The RPOs first evaluated technical information to better understand how their states and tribes impact Class I areas across the country, and then pursued the development of regional strategies to reduce emissions of particulate matter (PM) and other pollutants leading to regional haze.

IV. Requirements for a Regional Haze FIP

The following is a summary of the requirements of the Regional Haze Rule. *See* 40 CFR 51.308 for further detail regarding the requirements of the rule.

A. The CAA and the Regional Haze Rule

Regional haze FIPs must assure Reasonable Progress towards the national goal of achieving natural

[1] Visual range is the greatest distance, in kilometers or miles, at which a dark object can be viewed against the sky.

[2] Areas designated as mandatory Class I Federal areas consist of national parks exceeding 6000 acres, wilderness areas and national memorial parks exceeding 5000 acres, and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). In accordance with section 169A of the CAA, EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value. 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. 42 U.S.C. 7472(a). Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to ''mandatory Class I Federal areas.'' Each mandatory Class I Federal area is the responsibility of a ''Federal Land Manager.'' 42 U.S.C. 7602(i). When we use the term ''Class I area'' in this action, we mean a ''mandatory Class I Federal area.''

[3] Albuquerque/Bernalillo County in New Mexico must also submit a regional haze SIP to completely satisfy the requirements of section 110(a)(2)(D) of the CAA for the entire State of New Mexico under the New Mexico Air Quality Control Act (section 74–2–4).

[4] EPA's regional haze regulations require subsequent updates to the regional haze SIPs. 40 CFR 51.308(g)–(i).

visibility conditions in Class I areas. Section 169A of the CAA and EPA's implementing regulations require states, or EPA when implementing a FIP, to establish long-term strategies for making Reasonable Progress toward meeting this goal. The FIP must also give specific attention to certain stationary sources that were in existence on August 7, 1977, but were not in operation before August 7, 1962, and require these sources, where appropriate, to install BART controls for the purpose of eliminating or reducing visibility impairment. The specific regional haze FIP requirements are discussed in further detail below.

B. EPA's Authority To Promulgate a FIP

Under section 110(c) of the Act, whenever we find that a State has failed to make a required submission we are required to promulgate a FIP. Specifically, section 110(c) provides:

(1) The Administrator shall promulgate a Federal implementation plan at any time within 2 years after the Administrator—

(A) finds that a State has failed to make a required submission or finds that the plan or plan revision submitted by the State does not satisfy the minimum criteria established under [section 110(k)(1)(A)], or

(B) disapproves a State implementation plan submission in whole or in part, unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan. Section 302(y) defines the term ''Federal implementation plan'' in pertinent part, as:

> [A] plan (or portion thereof) promulgated by the Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a State implementation plan, and which includes enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions or emissions allowances)* * *.

Thus, because the Michigan and Minnesota failed to adequately establish BART limits for its subject taconite ore processing facilities we are required to promulgate a FIP.

C. Best Available Retrofit Technology (BART)

Section 169A of the CAA directs states, or EPA if implementing a FIP, to evaluate the use of retrofit controls at certain larger, often uncontrolled, older stationary sources in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the CAA requires EPA to implement a FIP to contain such measures as may be necessary to make Reasonable Progress toward the natural visibility goal, including a requirement that certain categories of existing major stationary sources [5] built between 1962 and 1977 procure, install, and operate the ''Best Available Retrofit Technology'' as determined by EPA. Under the Regional Haze Rule, EPA is directed to conduct BART determinations for such ''BART-eligible'' sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area.

On July 6, 2005, EPA published the *Guidelines for BART Determinations Under the Regional Haze Rule* at appendix Y to 40 CFR part 51 (hereinafter referred to as the ''BART Guidelines'') to assist states, or EPA if implementing a FIP, in determining which of their sources should be subject to the BART requirements and in determining appropriate emission limits for each applicable source. (70 FR 39104, July 6, 2005). In making a BART determination for a fossil fuel-fired electric generating plant with a total generating capacity in excess of 750 megawatts (MW), EPA must use the approach set forth in the BART Guidelines. EPA is encouraged, but not required, to follow the BART Guidelines in making BART determinations for other types of sources. Regardless of source size or type, EPA must meet the requirements of the CAA and our regulations for selection of BART, and EPA's BART analysis and determination must be reasonable in light of the overarching purpose of the regional haze program.

The process of establishing BART emission limitations can be logically broken down into three steps: First, EPA identifies those sources which meet the definition of ''BART-eligible sources'' set forth in 40 CFR 51.301; [6] second, EPA determines which of such sources ''emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area'' (a source which fits this description is ''subject to BART''); and third, for each source subject to BART, EPA then identifies the best available type and level of control for reducing emissions.

States, or EPA if implementing a FIP, must address all visibility-impairing pollutants emitted by a source in the BART determination process. The most significant visibility impairing pollutants are SO_2, NO_X, and PM.

A regional haze FIP must include source-specific BART emission limits and compliance schedules for each source subject to BART. Once EPA has made its BART determination, the BART controls must be installed and in operation as expeditiously as practicable, but no later than five years after the date of the final FIP. CAA section 169(g)(4) and 40 CFR 51.308(e)(1)(iv). In addition to what is required by the Regional Haze Rule, general SIP, or FIP, requirements mandate that the SIP, or FIP, must also include all regulatory requirements related to monitoring, recordkeeping, and reporting for the BART controls on the source. *See* CAA section 110(a).

V. EPA's BART Analysis of Michigan and Minnesota's Taconite Facilities

A. Sources Subject to BART

EPA agrees with Michigan and Minnesota with respect to the taconite facilities that the States determined to be subject to BART. These determinations are included in Minnesota's December 2009 Regional Haze Plan and Michigan's November 2010 Regional Haze Plan. EPA also agrees with the States' determination that BART for direct PM is satisfied by the taconite maximum achievable control technology (MACT) rule. See, National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing, 40 CFR part 63, subpart RRRRR. The primary sources that have been specifically identified as being subject to BART and requiring an analysis to establish BART are the taconite pelletizing, or indurating, furnaces identified in Table V–A.1. While they mean the same thing, we have chosen to refer to these furnaces as indurating furnaces or pelletizing furnaces in a manner consistent with how they are referred to by the States.

[5] The set of ''major stationary sources'' potentially subject to BART is listed in CAA section 169A(g)(7), and includes ''taconite ore processing facilities.''

[6] BART-eligible sources are those sources that have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were not in operation prior to August 7, 1962, but were in existence on August 7, 1977, and whose operations fall within one or more of 26 specifically listed source categories. 40 CFR 51.301.

TABLE V–A.1—LIST OF TACONITE FACILITIES

State	Company	Unit
Minnesota	U.S. Steel, Minntac	Grate-Kiln Lines 3–7.
Minnesota	Northshore Mining Company	Straight-Grate Furnaces 11 and 12.
Minnesota	United Taconite	Grate-Kiln Lines 1 and 2.
Minnesota	ArcelorMittal Steel	1 Straight-Grate.
Minnesota	Hibbing Taconite	Straight-Grate Lines 1–3.
Minnesota	U.S. Steel, Keetac	1 Grate-Kiln.
Michigan	Tilden Mining	Grate-Kiln Line 1.

The U.S. taconite iron ore industry uses two types of pelletizing machines or processes: Straight-grate and grate-kiln. A significant difference is that straight-grate kilns do not burn coal and they therefore have a much lower potential for emitting SO_2.

In the straight-grate kiln, a continuous bed of agglomerated green pellets is carried through different temperature zones with upward draft or downward draft blown through the pellets on the metal grate. Pellet residence time inside the machine is about 40 minutes. Fuel combustion chambers supply hot flue gas to a zone in the middle portion of the machine (combustion zone). (In order to make fully fluxed pellets, auxiliary burners need to be added to the preheating zone.) Fired pellets are cooled on the remaining portion of the machine. To protect the metal grate and other parts of the machine, about 20 percent of the cooled, fired pellets are used to make a hearth layer at the bottom and two sides of the pellet bed.

For the straight-grate kiln, used process gas consists of exhaust gas from the updraft drying zone and exhaust gas closer to the firing zone. The former can be called ''hood exhaust'' and the latter ''windbox exhaust.'' For many straight-grate kilns, both hood exhaust and windbox exhaust are directed to one common header. The common exhaust header has one ''hot side'' inlet to receive windbox exhaust and one ''cold side'' inlet to receive hood exhaust. From the common exhaust header, the exhaust gas is vented through four parallel stacks, which are outfitted with air pollution control equipment. For some older machines, two separate common headers are used to vent hood exhaust and windbox exhaust. The hood exhaust header vents through three stacks, and the wind exhaust (often referred to as ''waste gas'') header vents through two stacks.

Gases are passed numerous times through the pellet bed in order to heat and cool the pellets as they pass along a large grate. ''Windbox exhaust'' gases are derived from the down draft and preheat zones, but are passed through multiclone dust collectors before entering the wet scrubber/exhaust system. ''Hood exhaust'' gases from the updraft drying zone originate from the second cooling zone and pass directly into the wet scrubber/exhaust system. Windbox and hood exhaust gases partially mix in a common header before being vented to the atmosphere through a series of four stacks.

The grate-kiln system actually consists of a traveling grate, a rotary kiln, and an annular cooler. Pellet residence time inside the system is about 55 minutes (less than 10 minutes in the grate, about 20 minutes in the kiln, and about 30 minutes in the cooler). The grate-kiln system does not need a hearth layer for the grate, which handles only drying and preheating. The rotary kiln does not need a hearth layer, either, because it is lined with refractory material. One waste gas stack, or two side-by-side waste gas stacks, is used for the grate-kiln system.

Combustion gases for heating the pellets are directed up a large rotating kiln and then down through the pellet bed in the preheat zone. The gases are then used for initial heating and drying of the green pellet feed. Gases used for cooling the hot pellets are also used to dry and heat the pellets. Depending on the operation, the waste gases are passed through one or more scrubbers and vented through one or more separate stacks.

It is very common to use intermediate cyclones to clean the gas stream in the straight grate and grate-kiln pelletizers, as it is ducted to various locations in the grate. The cyclones protect the blades of gas movers (fans) and recover good materials (particles of high iron content). Inclined plates are also used along with periodic water wash to remove ''solid spills'' under the grate to recover the iron units. These measures also help reduce dust loading near the waste gas stack, even though they are not considered air pollution control equipment.

B. BART Five-Factor Determinations and Proposed FIP Emission Limits for NO_X and SO_2

EPA proposes to find that BART for NO_X for indurating furnaces is low NO_X burners for both straight-grate and grate-kilns. The feasibility of using low NO_X burners on grate-kilns is based on an October 26, 2011 ''Summary Report for USS On NO_X reduction for Kilns #6 and 7'' by S. Londerville, which documents a baseline of 4 pounds per million British Thermal Units (lbs/MMBtu) when burning gas; the December 1, 2011 ''U.S. Steel Minntac Line 6 Low NO_X Main Burner Final Report & Facility NO_X Management,'' which states that there has been neither an increase in fuel consumption nor degradation of pellet quality with the use of a low NO_X burner; and continuous emission monitoring system (CEMS) data from U.S. Steel Minntac Line 6. These data support a limit of 1.2 lbs/MMBtu on a 30-day rolling average. Also, cost-calculations for Minntac's Line 6 result in cost-effectiveness values of $441/ton of NO_X reduced when burning coal and gas and $210/ton of NO_X reduced when burning gas.

In a July 2, 2012, conversation with U.S. Steel and COEN, EPA discussed the potential for any negative issues associated with the use of Minntac's low NO_X burners. During this conversation it was stated that although there was initially an increase in fuel use, that increase has been eliminated so there is not an increase in MMBtu/ton of NO_X emitted. There is also no increase in combustion related emissions, such as carbon monoxide or volatile organic compounds, and there is no reason for SO_2 emissions to increase through use of a low NO_X burner. There is a small (less than 1 MW/hr) increase in electricity use and no increase in water use. U.S. Steel was certain that there was absolutely no product/pellet degradation. Some of their pellets are shipped to other (non-U.S. Steel) customers and some are shipped a long distance so there can be no slip (*e.g.* pellet degradation) in quality. The July 2, 2012 conversation also included discussion of installation schedules during which it was stated that engineering for adding additional burners would be expected to take about 6 months, although engineering could be combined for installation of more than one burner. Installation of new low NO_X burners would need to be timed with line outages, which typically occur about 6 months apart, and could take about a year.

The feasibility of low NO_X burners on straight-grate kilns is documented in a September 19, 2011 summary of findings presented to the Minnesota Pollution Control Board titled ''Results of Testing at ¼-Scale of LE Low NO_X Burner Prototype for Straight-Grate Pelletizing Furnaces'' by Fives North American Combustion, Inc. (Fives) for Essar (formerly Minnesota) Steel (Essar), and in presentations made at the April 17 and 18, 2012 Society for Mining, Metallurgy and Exploration meeting in Duluth, Minnesota. These presentations were ''Reducing NO_X from Pelletizing Furnaces,'' by Fives and ''Environmental Benefits for the Adaptation of Commonly Used Low-NO_X Burner Technology to a Straight-Grate Natural Gas Fired Taconite Indurating Furnace,'' by Lori L. Stegink, from Barr Engineering and Kevin Kangas from Essar. These presentations revealed that Essar and Fives first examined the applicability of numerous traditional methods for reducing NO_X from combustion as well as post-treatment methods for NO_X removal. This was followed by successful bench-scale testing of Fives low NO_X LE burners to achieve NO_X reductions greater than 70 percent in a straight-grate pelletizing furnace. Therefore Essar and Fives proceeded with a joint $2 million investment in a test rig to simulate a straight-grate pelletizing furnace. In the ¼-scale test rig, the cross sectional area scaling was very representative of actual furnace geometry, as were the energy inputs and flows. This testing demonstrated a 90 percent reduction in NO_X emissions and a rate of 0.25 lbs. NO_X/MMBtu at an estimated cost-effectiveness of $370/ton. Based on the results of this test program, it was concluded that NO_X emissions in the actual furnace should be consistent with those measured in the ¼ scale test conditions. Subsequent conversations with representatives of Essar and Fives indicated that an increase in fuel use and emissions from other pollutants is not anticipated and that the type of furnace that Essar will be using is the most difficult design for NO_X control. Based on the range of cost-effectiveness values provided, a conservative value of $500/ton will be used as the cost-effectiveness value for low NO_X burners.

EPA proposes to determine that BART for SO_2 for straight-grate kilns is existing controls because these furnaces do not burn coal. EPA also proposes to find that BART for SO_2 is existing controls at Keetac and Minntac because the cost-effectiveness of additional controls is excessive due to the amount of coal fired, the sulfur content of the coal used there and their existing controls.

For Tilden Line 1 and United Taconite's Lines 1 and 2, EPA is proposing to determine that a dry flue-gas desulfurization (FGD) system (for United Taconite's Lines 1 and 2), and either a wet or dry FGD system at Tilden, with an emission rate of 5 parts per million by volume (ppmv) of SO_2, or a 95 percent emission reduction requirement, on a 30-day rolling average, has been determined to be BART for SO_2. The cost-effectiveness of these controls has been determined based upon EPA's Air Pollution Control Cost Manual, information provided in Tilden's and United Taconite's BART determinations, information on existing operating costs supplied by United Taconite and a summary of information provided on capital and operating costs as well as the SO_2 emission rate provided by FGD manufacturers.

Also, there is no indication that the useful life of any of these facilities is less than 20 years.

BART analyses conducted for each of the subject facilities are presented below. EPA will carefully consider any comments that disagree with any of its facts or conclusions. It should be noted, however, that more weight will be provided to fact-based comments such as test results or vendor quotes and less to unsubstantiated engineering estimates or opinions.

Please note that in the following analyses, unless otherwise specified, information related to the technical and economic feasibility of various controls was provided in Minnesota's December 30, 2009 Regional Haze SIP submission and reflects information provided in the company specific BART analyses. The same is also true for Michigan and Tilden.

1. U.S. Steel Minntac

U.S. Steel Minnesota Ore Operations (Minntac) operates five grate-kiln indurating furnaces which are identified in table V–B.1 below.

TABLE V–B.1 MINNTAC EMISSION UNITS

Emission unit name	EU No.[7]	Control equipment and stack numbers
Line 3 Indurating Furnace	EU225	CE146/SV103
Line 4 Indurating Furnace	EU261	CE103/SV118
Line 5 Indurating Furnace	EU282	CE113/SV127
Line 6 Indurating Furnace	EU315	CE126/SV144
Line 7 Indurating Furnace	EU334	CE136/SV151

a. *NO_X BART Analysis*

Step 1: Identify all Available Retrofit Control Technologies

The following NO_X retrofit control technologies have been identified as being available for indurating furnaces:

- External Flue Gas Recirculation,
- Low NO_X Burners,
- Induced Flue Gas Recirculation Burners,
- Energy Efficiency Projects,
- Ported Kilns,
- Alternate Fuels, and
- Selective Catalytic Reduction (SCR).

Step 2: Eliminate Technically Infeasible Options

Minntac eliminated External Flue Gas Recirculation and Induced Flue Gas Recirculation Burners from consideration since they were technically infeasible for the specific application to pellet furnaces due to the high oxygen content of the flue gas. Minntac eliminated Energy Efficiency Projects due to the difficulty of assigning a general potential emission reduction for this category. Minntac noted in their analysis that the facility has already implemented several energy efficiency projects and that it will continue to evaluate and implement

[7] The MPCA organizes conditions and illustrates associations in its permits using the Emission Unit (EU), Control Equipment (CE), and Stack/Vent (SV) numbers.

energy efficiency projects. Minntac eliminated Alternative Fuels because the environmental and economic benefits of such a change are uncertain and Minntac believes that this option is not mandated by EPA. Also, U.S. Steel documented the infeasibility of SCR controls. Two SCR vendors declined to bid on NO_X reduction testing at Minntac. EPA agrees that SCR controls are infeasible for indurating furnaces. The remaining technologies, considered by Minntac to be technically feasible, include:

- Low NO_X burners,
- Low NO_X burners + Ported kilns (Lines 4 and 5), and
- Ported kilns (Lines 3, 4, and 5—kilns on lines 6 and 7 are already ported).

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

The following tables illustrate the assumed control efficiencies and the projected NO_X emission reductions projected by Minntac with the technically feasible control technologies.

TABLE V–B.2—PELLET FURNACE PROJECTED NO_X EMISSION REDUCTIONS

[TPY]

NO_X Control technology	Assumed control efficiency (percent)	Line 3	Line 4	Line 5	Line 6	Line 7
None (Baseline)		1,345	1,812	1,820	1,776	1,928
Low NO_X burners + Ported kilns	15	na	249	273	na	na
Low NO_X burners	10	na	181	182	na	193
Ported kilns	5	67	91	91	na	na

Step 4: Evaluate Impacts and Document the Results

Minntac's estimates of the annualized pollution control cost of operating the various control technologies are shown in the following table.

TABLE V–B.3—PELLET FURNACE PROJECTED NO_X CONTROL COST

[$/Ton]

NO_X Control technology	Line 3	Line 4	Line 5	Line 6	Line 7
Low NO_X burners + Ported kilns	na	$5,844	$5,974	na	na
Low NO_X Burners	na	768	765	na	$588
Ported kilns	$5,076	5,209	5,186	na	na

Step 5: Evaluate Visibility Impacts

See Section V.C.

Step 6: Propose BART

EPA is proposing a limit of 1.20 lbs/MMBtu on a 30-day rolling average for all lines to be achieved as follows: 1 year after the effective date of this rule for line 6, 2 years after the effective date for Line 7, 3 years after the effective date for Line 4, 4 years after the effective date for Line 5 and 4 years, and 11 months after the effective date for Line 3.

b. *SO_2 BART Analysis*

Lines 3, 4, and 5 can burn natural gas, wood and fuel oil, but natural gas and wood are used most frequently. Since these fuels are low in sulfur, the primary source of sulfur in these furnaces is the iron ore used to form the pellets. Additional sulfur may be present in the additives used in the pellets. In addition to natural gas, wood, and fuel oil, coal is used in Lines 6 and 7.

The lines are controlled by wet scrubbers designed to remove PM. Since collateral SO_2 reductions occur within the existing wet scrubbers, they are considered low efficiency SO_2 scrubbers. Minntac estimates that these existing scrubbers remove 15 to 30 percent of the SO_2 in the exhaust gas from these lines.

Step 1: Identify all Available Retrofit Control Technologies

Minntac identified the following SO_2 retrofit control technologies:[8]

- Wet Walled Electrostatic Precipitator (WWESP),
- Wet Scrubbing (High and Low Efficiency),
- Dry Sorbent Injection (Dry Scrubbing Lime/Limestone Injection),
- Spray Dryer Absorption,
- Energy Efficiency Projects,
- Alternate Fuels, and
- Coal Processing.

Step 2: Eliminate Technically Infeasible Options

Minntac eliminated Dry Sorbent Injection, Spray Dryer Absorption, Alternative Fuels, and Coal Drying from consideration due to technical infeasibility. With Dry Sorbent Injection and Spray Dryer Absorption, the high moisture content of the exhaust would lead to saturation of the baghouse filter cake and plugging of the filters and the dust collection system. To achieve a reduction of SO_2 emissions through alternative fuel usage, the source must switch from a high sulfur fuel to a lower sulfur fuel. Lines 3, 4, and 5 are burning natural gas and wood, both of which are low in sulfur. Lines 7 and 8 are allowed to burn coal. Due to the uncertainty of alternative fuel costs, the potential of replacing one visibility impairment pollutant for another, and the fact that BART cannot mandate a fuel switch, Minntac did not evaluate this option further. Coal drying requires a source of excess heat or low pressure steam. This heat source is not available at the Minntac facility so coal drying was found to be technically infeasible.

In addition, Minntac has already implemented Energy Efficiency Projects. The company indicated that the potential fuel reductions and the

[8] See September 8, 2006 BART analysis submitted to MPCA by U.S. Steel, *http://www.pca.state.mn.us/index.php/view-document.html?gid=2228.*

commensurate emission reductions for future Energy Efficiency Projects cannot accurately be predicted without specific details; since no particular project has been envisioned, the company did not evaluate this option any further.

Minntac evaluated the possibility of improving the SO_2 removal efficiency of the existing scrubbers through the additions of caustic, lime, or limestone in the scrubber water to raise the pH. The existing scrubbers on lines 3–7 currently operate at a neutral pH. The scrubbers, piping, pumps, and water tanks were not designed to operate at a higher pH so corrosion of the system would be a concern. Also, the additions and increased SO_2 removal would create additional solids and sulfates in the scrubber discharged to the tailings basin. This would require substantial and expensive treatment to maintain an acceptable water quality which could be discharged through the existing National Pollutant Discharge Elimination System permit. The new scrubber on Line 3 is a recirculating scrubber which operates at a pH that is typically less than 7. The scrubber was operated temporarily at a higher pH, but plugging and other operational problems resulted. Based on these concerns, Minntac found the improvement of SO_2 removal efficiency of the existing scrubbers to be impractical and did not further consider this option.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Minntac estimated the control efficiency of WWESPs to be approximately 80 percent. A secondary wet scrubber was estimated to control roughly 60 percent of the SO_2 remaining after the existing scrubber. The following tables illustrate the SO_2 emission reductions projected by Minntac with the technically feasible control technologies.

TABLE V–B.4—ANNUAL SO_2 EMISSIONS
[TPY]

	Line 3	Line 4	Line 5	Line 6	Line 7	Total
Baseline SO_2 Emissions	329.4	447.5	447.5	544.8	544.8	2314

TABLE V–B.5—PROJECTED SO_2 EMISSION REDUCTIONS
[TPY]

SO_2 Control technology	Line 3	Line 4	Line 5	Line 6	Line 7	Total
WWESP	263.5	358.0	358.0	435.9	435.9	1851.3
Secondary Wet Scrubber	197.6	268.5	268.5	326.9	326.9	1388.4

Step 4: Evaluate Impacts and Document the Results

Cost of Control

Minntac estimated the annualized pollution control cost of installing and operating WWESPs on Lines 3, 4, and 5 to be between $20,000 and $24,000 per ton of SO_2 removed. The cost of installing and operating a secondary wet scrubber on these lines was estimated to be between $14,000 and $16,000 per ton of SO_2 removed. The annualized pollution control cost of installing and operating WWESPs on Lines 6 and 7 was estimated to be approximately $18,000 per ton of SO_2 removed. The cost of installing and operating a secondary wet scrubber on these lines was estimated to be between approximately $12,000 per ton of SO_2 removed.

Energy and Non-Air Quality Environmental Impacts

There are no energy or non-air quality impacts because, as discussed above and in the Step 6 discussion, no additional controls were determined to be required.

Step 5: Evaluate Visibility Impacts

Additional SO_2 controls for Minntac are not reasonably cost effective, so visibility impacts were not modeled for additional SO_2 controls.

Step 6: Propose BART

Although we do not agree that the Minnesota Pollution Control Agency (MPCA) and Minntac have adequately documented the infeasibility of all of the SO_2 controls described above, we agree that additional SO_2 controls are not economically reasonable and are, therefore, not necessary for BART. EPA is proposing to determine that BART is existing controls. Based on CEM data provided by Minntac for 2010, 2011, and part of 2012, EPA is proposing the following limits: 71.3 lb SO_2/hr for Line 3, 56.1 lb SO_2/hr for Line 4, 67.9 lb SO_2/hr for Line 5, 64.5 lb SO_2/hr for Line 6, and 67.1 lb SO_2/hr for Line 7. These limits are measured on a 30-day rolling average and compliance is required within 30 days after the effective date of this rule.

c. Non-Furnace BART Analysis

Minntac also operates four heating boilers that are subject to a full BART analysis. The facility's two Step I Heating Boilers (#1 and #2) are each rated at 104 MMBtu/hr and the two Step III Heating Boilers (#4 and #5) are rated at 153 MMBtu/hr. Each boiler is capable of burning natural gas and fuel oil.

Step 1: Identification of Available Retrofit Control Technologies

The following NO_X retrofit control technologies have been identified as being available for the heating boilers:

- External Flue Gas Recirculation,
- Low-NO_X Burners,
- LNB with Overfire Air (LNB/OFA),
- Induced Flue Gas Recirculation Burners,
- Energy Efficiency Projects,
- Alternate Fuels,
- Low Temperature Oxidation,
- Selective Catalytic Reduction,
- Regenerative SCR, and
- Selective Non-Catalytic Reduction.

Step 2: Eliminate Technically Infeasible Options

Minntac eliminated External Flue Gas Recirculation from consideration since it was technically infeasible for the boilers based on Minntac staff judgment that the existing fireboxes for the boilers would be unable to accommodate longer flame length to avoid flame impingement. Minntac eliminated energy efficiency projects due to the difficulty of assigning a general potential emission reduction for this category, but stated that Minntac will continue to evaluate and implement energy efficiency projects. Minntac eliminated alternative fuels because the environmental and economic benefits of such a change are uncertain, the limited fuel options available, and the fact that natural gas is the typical fuel burned in the boilers. Minntac stated that it would continue to evaluate and implement alternative fuel usage as feasible.

Step 3: Evaluation of the Control Effectiveness of the Remaining Control Technologies

The following table illustrates the assumed control efficiencies and the projected NO_X emission reductions projected by Minntac with the technically feasible control technologies.

TABLE V–B.6—HEATING BOILER PROJECTED NO_X EMISSION REDUCTIONS

[TPY]

NO_X Control technology	Control efficiency	Boilers #1, #2, #4, #5	Emissions	Cost
None (Baseline)		13.8–14.8	56.7	
Low Temperature Oxidation	90%	12.4–13.3	5.7	$23,668–$27,713
SCR	80%	11.0–11.8	11.3	$50,632-$60,211
LNB/Flue gas recirculation	75%	10.4–11.1	14.2	$15,558–$20,299
Regenerative SCR	70%	9.7–10.4	17.0	$22,879–$30,710
LNB/Overfire Air	67%	9.2–9.9	18.7	$14,282–$18,634
Low NO_X Burner	50%	6.9–7.4	28.3	$6,653–$8,646
Selective Non-Catalytic Reduction	50%	6.9–7.4	28.3	$42,037–$51,494

Step 4: Evaluate Impacts and Document the Results

The NO_X emissions generated by the four heating boilers at the Minntac facility total 56.7 TPY. The most cost efficient control is low NO_X burners at $6,653 to $8,646 per ton, which would yield a 28.4 TPY reduction.

Step 5: Evaluate Visibility Impacts

Additional NO_X controls are not required because they are not reasonably cost-effective. Therefore there are no resulting visibility impacts.

Step 6: Propose BART

Given that the control options result in modest reductions in NO_X emissions on a TPY basis, that modest reduction would need to provide a strong visibility improvement or be trivial in cost to justify a BART limit indicative of additional control. That is not the case for the Minntac heating boilers. Minntac's current Title V permit (13700005—002) does not include NO_X emission limits for the heating boilers. Thus, EPA is not proposing a NO_X emission limit for the Minntac heating boilers. EPA is proposing to determine that the existing operational requirements, including fuels (natural gas with fuel oil as back up) and compliance requirements in the existing permits are NO_X BART for the Minntac heating boilers.

2. Northshore Mining

Northshore operates two straight-grate indurating furnaces which are identified in Table V–B.7 below.

TABLE V–B.7—NORTHSHORE EMISSION UNITS

Emission unit name	EU No.	Control equipment and stack numbers
Indurating Furnace #11—Hood Exhaust	EU100	CE101/SV101, CE102/SV102, CE103/SV103.
Indurating Furnace #11—Waste Gas	EU104	CE104/SV104, CE105/SV105.
Indurating Furnace #12—Hood Exhaust	EU110	CE111/SV111, E112/SV112, CE113/SV113.
Indurating Furnace #12—Waste Gas	EU114	CE114/SV114, CE115/SV115.

a. NO_X BART Analysis

Step 1: Identify All Available Retrofit Control Technologies

The following NO_X retrofit control technologies have been identified as being available for indurating furnaces:

- External Flue Gas Recirculation,
- Low-NO_X Burners,
- Induced Flue Gas Recirculation Burners,
- Energy Efficiency Projects,
- Ported Kilns,
- Alternate Fuels, and
- Selective Catalytic Reduction.

Step 2: Eliminate Technically Infeasible Options

Northshore eliminated External Flue Gas Recirculation and Induced Flue Gas Recirculation Burners from consideration since they were technically infeasible for the specific application to pellet furnaces due to the high oxygen content of the flue gas. Northshore eliminated Energy Efficiency Projects due to the difficulty of assigning a general potential emission reduction for this category. The company has already implemented several energy efficiency projects and will continue to evaluate and implement energy efficiency projects. Northshore's use of straight grate indurating furnaces makes the use of Ported Kilns infeasible, since they can be used only at grate-kiln furnaces. Northshore eliminated Alternative Fuels because the environmental and economic benefits of such a change are uncertain and Northshore believes that this option is not mandated by EPA. In addition, Northshore's furnace is currently incapable of handling solid fuels. Also, U.S. Steel documented the infeasibility of SCR controls. (see section V.B.1.a., above).

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

The following table illustrates the NO_X emission baseline for Northshore and the reductions achievable using low NO_X burners.

TABLE V–B.8—PROJECTED ANNUAL NO_X EMISSION REDUCTION
[TPY]

NO_X Control	Assumed control	Furnace 11		Furnace 12	
		Hood exhaust	Waste gas	Hood exhaust	Waste gas
None (Baseline)		112.4	273.7	109.9	267.7
Low NO_X Burners	70%	79	192	77	187

Step 4: Evaluate Impacts and Document Results

Cost of Control

TABLE V–B.9—PELLET FURNACE PROJECTED NO_X CONTROL
[Cost per ton of pollutant removed]

NO_X Control Technology	Furnace 11 (hood)	Furnace 11 (waste)	Furnace 12 (hood)	Furnace 12 (waste)
Low NO_X Burners	$500	$500	$500	$500

Step 5: Evaluate Visibility Impacts

See section V.C.

Step 6: Propose BART

EPA is proposing a limit of 1.2 lbs/MMBtu on a 30-day rolling average for all lines to be achieved as follows: 1 year and 6 months after the effective date for Line 11 and 2 years and 6 months after the effective date for Line 12.

b. SO_2 BART Analysis

Although the indurating furnaces can burn both natural gas and fuel oil, natural gas is the primary fuel. Since natural gas is low in sulfur, the primary source of SO_2 emissions is from trace amounts of sulfur in the iron concentrate and binding agents. Sulfur is also present in distillate fuel oil.

Both lines are controlled by wet-walled electrostatic precipitators using caustic reagent.

Step 1: Identify All Available Retrofit Control Technologies

Northshore identified the following SO_2 retrofit control technologies:[9]

- Wet-Walled Electrostatic Precipitator,
- Wet Scrubbing (High and Low Efficiency),
- Dry Sorbent Injection (Dry Scrubbing Lime/Limestone Injection),
- Spray Dryer Absorption,
- Energy Efficiency Projects,
- Alternate Fuels, and
- Coal Processing.

Step 2: Eliminate Technically Infeasible Options

Northshore eliminated Dry Sorbent Injection, Spray Dryer Absorption, Alternative Fuels, and Coal Drying from consideration due to technical infeasibility. With Dry Sorbent Injection and Spray Dryer Absorption, the high moisture content of the exhaust would lead to saturation of the baghouse filter cake and plugging of the filters and the dust collection system. Alternative Fuels were eliminated because Northshore is prohibited from burning solid fuels. Coal Drying is technically infeasible because Northshore does not burn coal.

Northshore indicated that the potential fuel reductions and the commensurate emission reductions for future Energy Efficiency Projects cannot accurately be predicted without specific details. Since no particular project has been envisioned, the company did not evaluate this option any further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Northshore estimated the control efficiency of a secondary WWESP to be approximately 80 percent. A secondary wet scrubber was estimated to control roughly 60 percent of the SO_2 remaining after the existing scrubber. The following tables illustrate the SO_2 emission reductions projected by Northshore with the technically feasible control technologies.

TABLE V–B.10—ANNUAL SO_2 EMISSIONS
[TPY]

	Furnace 11		Furnace 12		Total
	Hood exhaust	Waste gas	Hood exhaust	Waste gas	
Baseline SO_2 Emissions	28.6	9.5	26.3	8.8	73.2

[9] See BART analysis submitted to MPCA by Northshore Mining Company in September 2006, *http://www.pca.state.mn.us/index.php/view-document.html?gid=2225*.

TABLE V–B.11—PROJECTED SO_2 EMISSION REDUCTIONS

[TPY]

SO_2 control technology	Furnace 11		Furnace 12		Total
	Hood exhaust	Waste gas	Hood exhaust	Waste gas	
WWESP	22.9	7.6	21.0	7.0	58.5
Secondary Wet Scrubber	17.2	6.7	15.8	5.3	45.0

Step 4: Evaluate Impacts and Document the Results

Cost of Control

Northshore estimated the annualized pollution control cost of installing and operating secondary WWESPs ranged from roughly $180,000 to $540,000 per ton of SO_2 removed. The cost of installing and operating a secondary wet scrubber was estimated to be between $140,000 and $420,000 per ton of SO_2 removed.

Energy and Non-air Quality Environmental Impacts

Because the cost of additional SO_2 controls for Northshore does not meet a reasonable definition of cost-effective technology, no further evaluation of these alternatives was conducted.

Step 5: Evaluate Visibility Impacts

Additional SO_2 controls for Northshore are not reasonably cost effective, so visibility impacts were not modeled for additional SO_2 controls.

Step 6: Propose BART

Although we do not agree that MPCA and Northshore have adequately documented the infeasibility of all of the SO_2 controls described above, we agree that, because Northshore is burning natural gas and fuel oil, additional SO_2 controls are not economically reasonable and are, therefore, not necessary for BART. EPA is proposing to determine that BART is existing controls. In its regional haze submittal, MPCA also concluded that BART was existing controls and set a limit of 0.0651 lb SO_2/long ton of pellets fired (finished) measured on a 30-day rolling average. Northshore provided 2011 performance testing data which showed an average production rate of 250 long ton of pellets fired (finished)/hr for Furnace 11 and 263 long ton of pellets fired (finished)/hr for Furnace 12. Based on these production rates and MPCA's limit, EPA is proposing the following limits: 16.3 lb SO_2/hr for Furnace 11 and 17.1 lb SO_2/hr for Furnace 12, measured on a 30-day rolling average. These limits do not apply when the subject emissions unit is burning fuel oil. In addition, EPA is proposing to require that the emissions from SV101, SV102, SV103, SV104, SV105, SV111, SV112, SV113, SV114, and SV115 for Furnaces 11 and 12 be subject to an 80.0 percent emission reduction requirement. Compliance is to be achieved with these limits within 6 months after the effective date of this rule.

c. Non-Furnace BART Analysis

Northshore also operates two process boilers that are subject to BART. Both process boilers were installed in 1965 and are rated at 79 MMBtu/hr. The boilers are capable of burning fuel oil and natural gas.

Step 1: Identification of Available Retrofit Control Technologies

The following NO_X retrofit control technologies have been identified as being available for the process boilers:

- External Flue Gas Recirculation,
- Low-NO_X Burners,
- Overfire Air,
- Induced Flue Gas Recirculation Burners,
- Energy Efficiency Projects,
- Alternate Fuels,
- Non-Selective Catalytic Reduction,
- Selective Catalytic Reduction,
- Regenerative SCR, and
- Selective Non-Catalytic Reduction.

Step 2: Elimination of Technically Infeasible Options

Northshore found External Flue Gas Recirculation to be technically infeasible and eliminated it from further consideration because Northshore's process boilers lack the capability needed to controlled combustion conditions at the boiler tip. Overfire air was eliminated due to the small size of Northshore's process boilers and the number of burners. Northshore eliminated energy efficiency projects due to the difficulty of assigning a general potential emission reduction for this category. However, it has already implemented energy efficiency projects and it will continue to evaluate and implement energy efficiency projects. Northshore also rejected alternate fuels, as the process boilers burn distillate fuel oil and natural gas only. As those fuels have low nitrogen content, even a fuel alternative with no nitrogen content would provide little benefit. Northshore also believes that this option is not mandated by EPA and furthermore, Northshore's boilers are incapable of handling solid fuels.

Northshore identified low-NO_X burners, induced flue gas recirculation burners, selective catalytic reduction, and selective non-catalytic reduction as the only technically feasible alternative from the list above. These technologies were then evaluative for cost-effectiveness.

Step 3: Evaluation of the Control Effectiveness of the Remaining Control Technologies

The following table illustrates the NO_X emission reductions projected by Northshore with the technically feasible technologies.

TABLE V–B.12—PROJECTED ANNUAL NO_X EMISSION REDUCTIONS

[TPY]

NO_X Control technology	Control efficiency (percent)	Emissions	Cost
None (Baseline)		41.2	
Selective Catalytic Reduction	90	4.1	$30,160
Low-NO_X Burners w/Induced Flue Gas Recirculation	75	10.3	10,675
Low-NO_X Burners	50	20.6	723

TABLE V–B.12—PROJECTED ANNUAL NO_X EMISSION REDUCTIONS—Continued
[TPY]

NO_X Control technology	Control efficiency (percent)	Emissions	Cost
Selective Non-Catalytic Reduction	50	20.6	12,126

Step 4: Evaluate Impacts and Document Results

The NO_X emissions generated by the two process boilers are of modest size, totaling 41.2 TPY. The most cost efficient control is low NO_X burners at $723 per ton, which would produce a 20.6 TPY emission reduction for each unit.

Step 5: Evaluate Visibility Impacts

See section V.C.

Step 6: Propose BART

Low NO_X burners will reduce emissions from the process boilers at a modest cost, estimated at $723 per ton by Northshore. This control will reduce 20.6 TPY of NO_X emissions from each process boiler unit. Although the total 41.2 ton annual reduction is modest, the low cost of adding the control, on a per ton and total cost bases, makes it reasonable. Thus, EPA is proposing a NO_X emission limit of 0.085 lb/MMBtu on a 30-say rolling average for Northshore Mining's Process Boiler #1 and Process Boiler #2. Compliance is to be achieved with this limit within 5 years after the effective date of this rule. This represents the BART emission limit when low NO_X burners are added to each boiler unit.

3. United Taconite

United Taconite operates two grate-kilns which are identified in Table V–B.13 below.

TABLE V–B.13—UNITED TACONITE EMISSION UNITS

Emission unit name	EU No.	Control equipment and stack numbers
Line 1 Pellet Induration	EU40	SV046
Line 2 Pellet Induration	EU42	SV048, SV049

a. NO_X BART Analysis

Step 1: Identify All Available Retrofit Control Technologies

United Taconite identified the following NO_X retrofit control technologies as being available for indurating furnaces:

- External Flue Gas Recirculation,
- Low-NO_X Burners,
- Induced Flue Gas Recirculation Burners,
- Energy Efficiency Projects,
- Ported Kilns,
- Alternate Fuels, and
- Selective Catalytic Reduction.

Step 2: Eliminate Technically Infeasible Options

United Taconite eliminated External Flue Gas Recirculation and Induced Flue Gas Recirculation Burners from consideration since they were technically infeasible for the specific application to pellet furnaces due to the high oxygen content of the flue gas. United Taconite eliminated Energy Efficiency Projects due to the difficulty of assigning a general potential emission reduction for this category. The company has already implemented several energy efficiency projects and it will continue to evaluate and implement energy efficiency projects. United Taconite eliminated Alternative Fuels because the environmental and economic benefits of such a change are uncertain and United Taconite believes that this option is not mandated by EPA. Also, U.S. Steel documented the infeasibility of SCR controls. (see section V.B.1.a., above).

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Table V–B.14 illustrates the NO_X emission baseline for United Taconite and the reductions achievable using low NO_X burners.

TABLE V–B.14—PROJECTED ANNUAL NO_X EMISSION REDUCTIONS
[TPY]

NO_X Control	Assumed control	Line 1	Line 2
None (Baseline)		1643	3687
Low NO_X Burners	70%	1150	2581

Step 4: Evaluate Impacts and Document Results

TABLE V–B.15—PELLET FURNACE PROJECTED NO_X

NO_X Control	Line 1	Line 2
Low NO_X Burners	$500	$500

Step 5: Evaluate Visibility Impacts

See section V.C.

Step 6: Propose BART

A limit of 1.2 lbs/MMBtu on a 30-day rolling average for all lines to be achieved as follows: 1 year and 6 months after the effective date for Line 2 and 2 years and 6 months after the effective date for Line 1.

b. SO_2 BART Analysis

Step 1: Identify All Available Retrofit Control Technologies

In its BART analysis, United Taconite identified the following SO_2 reduction technologies as generally available to pellet furnaces:

- Wet scrubbing (high efficiency),
- Wet scrubbing (low efficiency),
- Wet walled electrostatic precipitator (WWESP),
- Dry sorbent injection,
- Spray dryer absorption,
- Alternative Fuels, and
- Energy efficiency projects.

Step 2: Eliminate Technically Infeasible Options

United Taconite eliminated dry sorbent injection and spray dryer absorption as technically infeasible technologies. United Taconite identified the use of alternative fuels and energy efficiency projects as technically feasible, but did not evaluate the costs associated with these options. United Taconite justified its failure to evaluate the costs associated with the use of alternative fuels and with energy efficiency projects stating that a BART analysis does not require analysis of such options. The company noted EPA's intent "for facilities to consider alternate fuels as an option, not to direct fuel choice" as its rationale for failing to conduct the cost analyses.

EPA disagrees with United Taconite's assessment of the feasibility of Flue-gas desulfurization, which will be discussed more fully elsewhere.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies and

Step 4: Evaluate Impacts and Document Results

TABLE V–B.16—SULFUR DIOXIDE REMOVAL ALTERNATIVES FOR UNITED TACONITE LINE 2

Control technology	Uncontrolled SO_2 emissions rate (lb/MMBtu)	Existing SO_2 removal efficiency (percent)	Additional control (BART analysis App A) (percent)	lb/MMBtu SO_2	Max hourly emission rate (total) (lb/hr)	Tons SO_2 emitted	Tons SO_2 removed	Total annualized cost	$/Ton SO_2 removed
Existing Scrubber	5.32	25	N/A	3.99	1037	3,900			
WWESP	5.32	25	80	0.80	207	780	3,120	$20,291,473	$6,504
Polishing Scrubber	5.32	25	60	1.60	415	1,560	2,340	9,166,715	3,917
Replacement Scrubber	5.32	N/A	60	2.13	553	2,080	1,820	7,107,434	3,905
Fuel Blend Changes	2.26	25	N/A	1.70	442	1,660	2,240	1,341,482	599
Fuel Blending + Polishing Scrubber	2.26	25	60	0.68	176	663	3,237	9,650,715	2,981

Table V–B.16 above identified alternatives for controlling SO_2 and their associated emissions rate, which MPCA determined were all cost-effective. At the time this table was prepared by MPCA, Line 1 was not equipped to burn coal. Line 1 can now burn coal and so presumably the above table, or something similar, would also apply to Line 1.

TABLE V–B.17—PROJECTED ANNUAL SO_2 EMISSION REDUCTIONS AND RESULTING COST-EFFECTIVENESS

SO_2 Control	Assumed control	Line 1	Line 2
Dry FGD Reductions	90%	1164	2475
Cost-Effectiveness		$2,000–$3,000 per ton	$2,000–$3,000 per ton.

EPA has determined that dry FGD scrubbers are feasible for United Taconite's two indurating furnaces.

Step 5: Evaluate Visibility Impacts

See section V.C.

Step 6: Propose BART

EPA is proposing a limit of 5 ppmv or a 95 percent reduction requirement, on a 30-day rolling average, to be achieved within 2 years after the effective date of this rule for Line 2 and 4 years after the effective date of this rule for Line 1.

4. ArcelorMittal

ArcelorMittal Minorca Mine Inc. operates one straight grate indurating furnace which is identified in Table V–B.18 below.

TABLE V–B.18 ARCELORMITTAL EMISSION UNITS

Emission unit name	EU No.	Control equipment and stack numbers
Indurating Furnace	EU026	CE014/SV014, CE015/SV015, CE016/SV016, CE017/SV017.

a. NO_X BART Analysis

Step 1: Identify All Available Retrofit Control Technologies

ArcelorMittal identified the following NO_X retrofit control technologies as being available for indurating furnaces:

- External Flue Gas Recirculation,
- Low-NO_X Burners,
- Induced Flue Gas Recirculation Burners,
- Energy Efficiency Projects,
- Ported Kilns, Alternate Fuels, and
- Selective Catalytic Reduction.

Step 2: Eliminate Technically Infeasible Options

ArcelorMittal eliminated External Flue Gas Recirculation and Induced Flue Gas Recirculation Burners from consideration since they were technically infeasible for the specific application to pellet furnaces due to the high oxygen content of the flue gas. ArcelorMittal eliminated Energy Efficiency Projects due to the difficulty of assigning a general potential emission reduction for this category. ArcelorMittal noted in its analysis that the facility has already implemented several energy efficiency projects and that it will continue to evaluate and implement energy efficiency projects. Ported Kilns were eliminated by ArcelorMittal because they are applicable only to grate kiln furnaces not to the straight grate indurating furnaces that ArcelorMittal employs. ArcelorMittal eliminated Alternative Fuels because the environmental and economic benefits of such a change are uncertain and ArcelorMittal believes that this option is not mandated by EPA. Also, ArcelorMittal's permit currently limits its fuels to natural gas and fuel oil. Also, U.S. Steel documented the infeasibility of SCR controls above. (See section V.B.1.a., above).

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Table V–B.19 illustrates the NO_X emission reductions from use of Low NO_X burners.

TABLE V–B.19—PROJECTED ANNUAL NO_X EMISSION REDUCTIONS

[TPY]

NO_X Control technology	Assumed control efficiency	Total
None (Baseline) [6]		3639
Low NO_X Burners	70%	2547

Step 4: Evaluate Impacts and Document Results

The annualized pollution control cost of installing and operating low NO_X burners is in Table V–B.20 below.

TABLE V–B.20—PELLET FURNACE PROJECTED NO_X CONTROL COST-EFFECTIVENESS

NO_X Controls	Indurating furnace
Low NO_X Burners	$500/ton.

Step 5: Evaluate Visibility Impacts

See section V.C.

Step 6: Propose BART

EPA is proposing a limit of 1.2 lbs/MMBtu on a 30-day rolling average to be achieved within 1 year and 6 months after the effective date of this rule for its indurating furnace.

b. SO_2 BART Analysis

Although the indurating furnaces can burn both natural gas and fuel oil, natural gas is the primary fuel. Since natural gas is low in sulfur, the primary source of sulfur at this furnace is the iron ore used to form the pellets. Additional sulfur may be present in the additives used in the pellets.

Furnace emissions are controlled by four wet scrubbers. The wet scrubbers are designed to remove PM and would be considered high efficiency PM wet scrubbers. Since collateral SO_2 reductions occur within the existing wet scrubbers, they are considered low efficiency SO_2 scrubbers. ArcelorMittal estimates that these existing scrubbers remove 15 to 30 percent of the SO_2 in the exhaust gas.

Step 1: Identify all Available Retrofit Control Technologies

ArcelorMittal identified the following SO_2 retrofit control technologies [10]:

- Wet Walled Electrostatic Precipitator (WWESP),
- Wet Scrubbing (High and Low Efficiency),
- Dry Sorbent Injection (Dry Scrubbing Lime/Limestone Injection),
- Spray Dryer Absorption (SDA),
- Energy Efficiency Projects, and
- Alternate Fuels.

Step 2: Eliminate Technically Infeasible Options

ArcelorMittal eliminated Dry Sorbent Injection, Spray Dryer Absorption, Alternative Fuels, and Coal Drying from consideration because they were technically infeasible. With Dry Sorbent Injection and Spray Dryer Absorption, the high moisture content of the exhaust would lead to saturation of the baghouse filter cake and plugging of the filters and the dust collection system. Alternative Fuels were eliminated because ArcelorMittal is prohibited from burning solids fuels and natural gas is a low-sulfur fuel. ArcelorMittal indicated that the potential fuel reductions and the commensurate emission reductions for future Energy Efficiency Projects cannot accurately be predicted without specific details; since no particular project has been envisioned, the company did not evaluate this option any further.

ArcelorMittal evaluated the possibility of improving the SO_2 removal efficiency of the existing scrubbers through the addition of caustic, lime, or limestone in the scrubber water to raise the pH. ArcelorMittal found this option to be impractical for several reasons. The scrubber currently operates at a neutral pH and the scrubbers, piping, pumps and water tanks were not designed to operate at a higher pH so corrosion of the system would be a concern. Also, the addition of caustic, lime, or limestone to increase SO_2 removal would create additional solids in the scrubber recirculation system which would require an increased blowdown rate and therefore an increased make-up water rate. Because the water balance at the facility is at maximum usage, additional make-up water is not available. Based on these concerns, ArcelorMittal did not further consider this option.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

ArcelorMittal estimated the control efficiency of WWESPs to be approximately 80 percent. A secondary wet scrubber was estimated to control roughly 60 percent of the SO_2 remaining after the existing scrubber. The following tables illustrate the SO_2 emission reductions projected by ArcelorMittal with the technically feasible control technologies.

TABLE V–B.21—ANNUAL SO_2 EMISSIONS

[TPY]

	Total
Baseline SO_2 Emissions	179.2

TABLE V–B.22—PROJECTED SO_2 EMISSION REDUCTIONS

[TPY]

SO_2 Control technology	Total
WWESP	143.2
Secondary Wet Scrubber	107.6

[10] See September 8, 2006 BART analysis submitted to MPCA by Mittal Steel USA—Minorca Mine, *http://www.pca.state.mn.us/index.php/view-document.html?gid=2224.*

Step 4: Evaluate Impacts and Document the Results

Cost of Control

ArcelorMittal estimated the annualized pollution control cost of installing and operating WWESPs to be about $116,000 per ton of SO_2 removed. The cost of installing and operating a secondary wet scrubber was estimated to be approximately $83,000 per ton of SO_2 removed.

Energy and Non-air Quality Environmental Impacts

Because the cost of additional SO_2 controls for ArcelorMittal does not meet a reasonable definition of cost effective technology, no further evaluation of these alternatives was conducted.

Step 5: Evaluate Visibility Impacts

Additional SO_2 controls for ArcelorMittal are not reasonably cost effective, so visibility impacts were not modeled for additional SO_2 controls.

Step 6: Propose BART

Although we do not agree that MPCA and ArcelorMittal have adequately documented the infeasibility of all of the SO_2 controls described above, we agree that, because ArcelorMittal is burning natural gas, additional SO_2 controls are not economically reasonable and are, therefore, not necessary for BART. EPA is proposing to determine that BART is existing controls. ArcelorMittal provided the results of emissions testing that was performed on the stacks associated with the furnace. Based on these test results, EPA is proposing a limit of 23.0 lb SO_2/hr, measured on a 30-day rolling average. This limit does not apply when the subject unit is burning fuel oil. Compliance is required within 30 days of the effective date of this rule.

5. Hibbing Taconite

Hibbing operates three straight grate indurating furnaces which are identified in Table V–B.23 below.

TABLE V–B.23—HIBBING EMISSION UNITS

Emission unit name	EU No.	Control equipment and stack numbers
Line 1 Pelletizing furnace	EU020	CE022/SV021, CE023/SV022, CE024/SV023, CE025/SV024.
Line 2 Pelletizing furnace	EU021	CE027/SV025, CE028/SV026, CE029/SV027, CE030/SV028.
Line 3 Pelletizing furnace	EU022	CE032/SV029, CE033/SV030, CE034/SV031, CE035/SV032.

a. NO_X BART Analysis

Step 1: Identify All Available Retrofit Control Technologies

Hibbing identified the following NO_X retrofit control technologies as available and applicable to pellet furnaces:

- External Flue Gas Recirculation,
- Low-NO_X Burners,
- Induced Flue Gas Recirculation Burners,
- Energy Efficiency Projects,
- Ported Kilns,
- Alternate Fuels, and
- Selective Catalytic Reduction with Reheat.

Step 2: Eliminate Technically Infeasible Options

Hibbing eliminated External Flue Gas Recirculation and Induced Flue Gas Recirculation Burners from consideration since they were technically infeasible for the specific application to pellet furnaces due to the high oxygen content of the flue gas. Hibbing eliminated Energy Efficiency Projects due to the difficulty of assigning a general potential emission reduction for this category. Hibbing noted in their Analysis that the facility has already implemented several energy efficiency projects and that it will continue to evaluate and implement energy efficiency projects. Ported Kilns were eliminated by Hibbing because they are applicable only to grate kiln furnaces not to the straight grate indurating furnaces that Hibbing employs. Hibbing eliminated Alternative Fuels because the environmental and economic benefits of such a change are uncertain and Hibbing believes that this option is not mandated by U.S. EPA. Also, Hibbing's permit currently limits its fuels to natural gas, fuel oil, and used oil. Also, U.S. Steel documented the infeasibility of SCR controls. (see section V.B.1.a., above).

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Table V–B.24 illustrates the NO_X emission reductions resulting from use of low NO_X burners.

TABLE V–B.24—PROJECTED ANNUAL NO_X EMISSION REDUCTIONS

[TPY]

NO_X Control technology	Assumed control efficiency	Line 1	Line 2	Line 3
None (Baseline)		2,143.5	2,143.5	2,247.1
Low NO_X Burners	70%	1,748	1,500	1,573

Step 4: Evaluate Impacts and Document Results

The annualized pollution control cost of installing and operating low NO_X burners is in Table V–B.25 below.

TABLE V–B.25—PELLET FURNACE PROJECTED NO_X CONTROL COST

[cost per ton of pollutant removed]

NO_X Control Technology	Line 1	Line 2	Line 3
Low NO_X Burners	$500	$500	$500

Step 5: Evaluate Visibility Impacts

See section V.C.

Step 6: Propose BART

EPA is proposing a limit of 1.2 lbs/MMBtu on a 30-day rolling average for all lines to be achieved as follows: 1 year and 6 months after the effective date for Line 1, 2 years and 6 months after the effective date for Line 3 and 3 years and 6 months for Line 2.

b. SO_2 BART analysis

Hibbing operates three straight grate indurating furnaces which are identified in table V–B.26 below.

TABLE V–B.26—HIBBING SO_2 EMISSION UNITS

Emission unit name	EU No.	Control equipment and stack numbers
Line 1 Pelletizing Furnace	EU020	CE022/SV021, CE023/SV022, CE024/SV023, CE025/SV024.
Line 2 Pelletizing Furnace	EU021	CE027/SV025, CE028/SV026, CE029/SV027, CE030/SV028.
Line 3 Pelletizing Furnace	EU022	CE032/SV029, CE033/SV030, CE034/SV031, CE035/SV032.

Although the indurating furnaces can burn both natural gas and fuel oil, natural gas is the primary fuel. Since natural gas is low in sulfur, the primary source of sulfur at these furnaces is the iron ore used to form the pellets. Additional sulfur may be present in the additives used in the pellets.

Each line is controlled by four venture-rod scrubbers. The wet scrubbers are designed to remove PM and would be considered high efficiency PM wet scrubbers. Since collateral SO_2 reductions occur within the existing wet scrubbers, they are considered low efficiency SO_2 scrubbers. Hibbing estimates that these existing scrubbers remove 15 to 30 percent of the SO_2 in the exhaust gas from Lines 1, 2, and 3.

Step 1: Identify all Available Retrofit Control Technologies

Hibbing identified the following SO_2 retrofit control technologies [11]:

- Wet Walled Electrostatic Precipitator (WWESP),
- Wet Scrubbing (High and Low Efficiency),
- Dry Sorbent Injection (Dry Scrubbing Lime/Limestone Injection),
- Spray Dryer Absorption,
- Energy Efficiency Projects, Alternate Fuels, and
- Coal Processing.

Step 2: Eliminate Technically Infeasible Options

Hibbing eliminated Dry Sorbent Injection, Spray Dryer Absorption, Alternative Fuels, and Coal Drying from consideration due to technical infeasibility. With Dry Sorbent Injection and Spray Dryer Absorption, the high moisture content of the exhaust would lead to saturation of the baghouse filter cake and plugging of the filters and the dust collection system. Alternative Fuels were eliminated because Hibbing is prohibited from burning solids fuels. Coal Drying is technically infeasible because Hibbing does not burn coal.

In addition, Hibbing has already implemented Energy Efficiency Projects. The company indicated that the potential fuel reductions and the commensurate emission reductions for future Energy Efficiency Projects cannot accurately be predicted without specific details; since no particular project has been envisioned, the company did not evaluate this option any further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Hibbing estimated the control efficiency of WWESPs to be approximately 80 percent. A secondary wet scrubber was estimated to control roughly 60 percent of the SO_2 remaining after the existing scrubber. Hibbing also expected that modifying the existing wet scrubber would control between 0 and 50 percent of the SO_2 currently emitted. The following tables illustrate the SO_2 emission reductions projected by Hibbing with the technically feasible control technologies.

TABLE V–B.27—ANNUAL SO_2 EMISSIONS

[TPY]

	Line 1	Line 2	Line 3	Total
Baseline SO_2 Emissions	202.2	179.5	188.1	569.8

TABLE V–B.28—PROJECTED SO_2 EMISSION REDUCTIONS

[TPY]

SO_2 Control technology	Line 1	Line 2	Line 3	Total
WWESP	161.8	143.6	150.5	455.9
Secondary Wet Scrubber	121.3	121.3	121.3	363.9

[11] See BART analysis submitted to MPCA by Hibbing Taconite Company in September 2006, *http://www.pca.state.mn.us/index.php/view-document.html?gid=2223.*

TABLE V–B.28—PROJECTED SO_2 EMISSION REDUCTIONS—Continued

[TPY]

SO_2 Control technology	Line 1	Line 2	Line 3	Total
Modification of Wet Scrubber	0–101.1	0–101.1	0–101.1	0–303.3

Step 4: Evaluate Impacts and Document the Results

Cost of Control

Hibbing estimated the annualized pollution control cost of installing and operating WWESPs to be about $37,000 per ton of SO_2 removed. The cost of installing and operating a secondary wet scrubber was estimated to be between $57,000 and $67,000 per ton of SO_2 removed. Given the space limitations and equipment additions that would be required to modify the existing wet scrubber, Hibbing determined that it would be more cost effective to construct a new, secondary scrubber; therefore, no cost estimate was provided for modifications to the existing wet scrubber.

Energy and Non-air Quality Environmental Impacts

There are no impacts because no additional controls are being proposed, as discussed in the Step 4 and Step 6 discussions.

Step 5: Evaluate Visibility Impacts

There are no visibility impacts because no additional controls are being proposed, as discussed in the Step 4 and Step 6 discussions.

Step 6: Propose BART

Although we do not agree that MPCA and Hibbing have adequately documented the infeasibility of all of the SO_2 controls described above, we agree that, because Hibbing is burning natural gas, additional SO_2 controls are not economically reasonable and are, therefore, not necessary for BART. EPA is proposing to determine that BART is existing controls. Hibbing provided the results of emissions testing that was performed in 2010 on the stacks associated with Lines 1, 2, and 3. Based on these test results, EPA is proposing the following limits: 56.0 lb SO_2/hr for Line 1, 63.0 lb SO_2/hr for Line 2, and 64.0 lb SO_2/hr for Line 3. These limits are measured on a 30-day rolling average and do not apply when the subject units are burning fuel oil. Compliance is required within 30 days of the effective date of this rule.

6. U.S. Steel Keewatin

U.S. Steel Keewatin (Keetac) operates one straight grate indurating furnace which is identified in Table V–B.29 below.

TABLE V–B.29—KEETAC EMISSION UNITS

Emission Unit Name	EU No.	Stack No.
Phase II Grate-Kiln Indurating Furnace	EU030	SV051

a. NO_X BART Analysis

Step 1: Identify All Available Retrofit Control Technologies

Keetac identified the following NO_X retrofit control technologies as available and applicable to pellet furnaces:

- External Flue Gas Recirculation,
- Low-NO_X Burners,
- Induced Flue Gas Recirculation Burners,
- Energy Efficiency Projects,
- Ported Kilns,
- Alternate Fuels, and
- Selective Catalytic Reduction with Reheat.

Step 2: Eliminate Technically Infeasible Options

Keetac eliminated External Flue Gas Recirculation and Induced Flue Gas Recirculation Burners from consideration since they were technically infeasible for the specific application to pellet furnaces due to the high oxygen content of the flue gas. The company indicated that the potential fuel reductions and the commensurate emission reductions for future Energy Efficiency Projects cannot accurately be predicted without specific details; since no particular project has been envisioned, the company did not evaluate this option any further. Keetac eliminated Alternative Fuels because the furnace already uses solid fuels that result in lower flame temperature and, thus, lower NO_X emissions. Switching to another fuel such natural gas (which Keetac already is capable of using) could exchange one visibility impairing pollutant for another (NO_X for SO_2). Keetac also believes that this option is not mandated by EPA. Keetac identified Ported Kilns and Selective Catalytic Reduction with conventional Reheat as the only technologies that are technically feasible. Also, U.S. Steel documented the infeasibility of SCR controls (see section V.B.1.a., above).

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Table V–B.30 identifies the projected NO_X emission reductions resulting from use of low NO_X burners.

TABLE V–B.30—PROJECTED ANNUAL NO_X EMISSION REDUCTIONS

NO_X control technology	Assumed control efficiency (percent)	Phase II furnaces (TPY)
None (Baseline)		4,154.0
Low NO_X Burners	70	2,908
Ported Kiln	5	207.7

Step 4: Evaluate Impacts and Document Results

TABLE V–B.30

[COST PER TON OF POLLUTANT REMOVED]

NO_X control technology	Phase II furnace
Low NO_X burners	$500
Ported Kiln–diff. due to discrepancy in submittal	$2,938–$6,032

Step 5: Evaluate Visibility Impacts

See section V.C.

Step 6: Propose BART

For NO_X, EPA is proposing a limit of 1.2 lbs/MMBtu on a 30-day rolling average for the Phase II furnace. Compliance is to be achieved within 1 year and 6 months after the effective date of this rule.

b. SO_2 BART Analysis

Step 1: Identify All Available Retrofit Control Technologies

Keetac identified the following SO_2 retrofit control technologies as available and applicable to pellet furnaces:

- Wet Walled Electrostatic Precipitator (WWESP),
- Secondary Wet Scrubber,
- Modifications to Existing Wet Scrubber,
- Dry Sorbent Injection (Dry Scrubbing Lime/Limestone Injection),
- Spray Dryer Absorption,
- Energy Efficiency Projects,
- Alternate Fuels, and
- Coal Processing.

Step 2: Eliminate Technically Infeasible Options

In considering control options for sulfur dioxide, Keetac eliminated Dry Sorbent Injection, Spray Dryer Absorption, Alternative Fuels, and Coal Processing from consideration since they were technically infeasible. With Dry Sorbent Injection and Spray Dryer Absorption, the high moisture content of the exhaust would lead to saturation of the baghouse filter cake and plugging of the filters and the dust collection system. The company indicated that the potential fuel reductions and the commensurate emission reductions for future Energy Efficiency Projects cannot accurately be predicted without specific details; since no particular project has been envisioned, the company did not evaluate this option any further. Alternative Fuels were eliminated due to the uncertainty of alternative fuel costs, the potential of replacing one visibility pollutant for another, and Keetac's belief that BART does not intend to mandate a fuel switch. Coal Processing requires a source of excess or of low pressure stream to remove water from the washed coal. There is no such heat source at Keetac so this option is technically infeasible.

In addition, Keetac has already implemented a number of Energy Efficiency Projects. The potential fuel reductions and the commensurate emission reductions for future Energy Efficiency Projects cannot accurately be predicted without specific details; since no particular project has been envisioned, the company decided not to evaluate this option any further.

Keetac evaluated modifying the existing scrubber to determine whether further SO_2 removal could be achieved. However, Keetac has recently installed new wet scrubbers to control SO_2 emissions. Since operation of the scrubber has been optimized, further improvement of the removal efficiency is not feasible and was not considered further in the report.

EPA disagrees with Keetac's assessment of the feasibility of Flue-gas desulfurization, which will be discussed more fully elsewhere.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Keetac evaluated WWESPs and Secondary Wet Scrubber as the two remaining retrofit technologies it deemed to be available and technically feasible. Keetac estimated the control efficiency of WWESPs to be approximately 80 percent. A secondary wet scrubber was estimated to control roughly 60 percent of the SO_2 remaining after the existing scrubber. The following table illustrates the SO_2 emission reductions projected by Keetac with the technically feasible control technologies.

TABLE V–B.32—PROJECTED SO_2 EMISSION REDUCTIONS

[TPY]

SO_2 Control technology	Phase II furnace
Baseline Emissions (existing scrubber)	850.5
WWESP (after existing scrubber)	760.4
Secondary Wet Scrubber (after existing scrubber)	570.3

Step 4: Evaluate Impacts and Document Results

Keetac's estimates of the annualized pollution control cost of installing and operating the WWESP and Secondary Wet Scrubber are shown in the table V–B.33 below.

TABLE V–B.33—PELLET FURNACE PROJECTED SO_2 CONTROL COST

[$ PER TON OF POLLUTANT REMOVED]

SO_2 Control technology	Phase II furnace
WWESP (after existing scrubber)	$15,165
Secondary Wet Scrubber (after existing scrubber)	8,870

Step 5: Evaluate Visibility Impacts

Visibility impacts were not modeled because additional reductions were not determined to be cost effective.

Step 6: Propose BART

Keetac's existing recirculating lime scrubber satisfies BART. Therefore, EPA is proposing that the scrubber be subject to a 57 percent SO_2 removal efficiency and a limit, based on CEMS data, of 225 lbs SO_2 per hour on a 30-day rolling average. In addition, EPA is proposing to require that the scrubber be operated at or above a pH of 7.5. Compliance with all SO_2 emission limits is required beginning 90 days from the effective date of this rule.

7. Tilden Mining Company LLC (TMC)

The BART-subject emission units include indurating furnace/grate-kiln EUKILN 1, EU PRIMARY CRUSHER, EU COOLER 1, EU DRYER 1, EU BOILER 1, and EU BOILER 2.

a. NO_X BART Analysis

Step 1: Identify All Available and Technically Feasible Retrofit Technologies

The following NO_X retrofit control technologies have been identified as being available and applicable for indurating furnaces:

- External Flue Gas Recirculation,
- Low-NO_X Burners,
- Induced Flue Gas Recirculation Burners,
- Energy Efficiency Projects,
- Ported Kilns,
- Alternate Fuels, and
- Selective Catalytic Reduction.

Step 2: Eliminate Technically Infeasible Options

Tilden eliminated External Flue Gas Recirculation and Induced Flue Gas Recirculation Burners from consideration since they were technically infeasible for the specific application to pellet furnaces due to the high oxygen content of the flue gas. Tilden eliminated Energy Efficiency Projects due to the difficulty of assigning a general potential emission reduction for this category. Ported Kilns were eliminated by Tilden because any reduction in NO_X would be minor. Tilden eliminated Alternative Fuels because the environmental and economic benefits of such a change are uncertain and Tilden believes that this option is not mandated by EPA. Also, U.S. Steel documented the infeasibility of SCR controls (see section V.B.1.a., above). Tilden also determined that non-selective catalytic reduction, regenerative selective reduction, selective non-catalytic reduction and low temperature oxidation are technically infeasible.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Table V–B.34 illustrates the NO_X emission reductions resulting from use of low NO_X burners.

TABLE V–B.34—PROJECTED ANNUAL NO_X EMISSION REDUCTIONS

NO_X Control Technology	Assumed control efficiency (percent)	Line 1 (tons per year)
None (Baseline)		4,613
Low NO_X burners	70	3,229

Step 4: Evaluate Impacts and Document Results

The annualized pollution control cost of installing and operating low NO_X burners is in Table V–B.35 below.

TABLE V–B.35—PELLET FURNACE PROJECTED NO_X CONTROL COST

[COST PER TON OF POLLUTANT]

NO_X Control technology	Indurating furnace
Low NO_X burners	$ 500/ton.

Step 5: Evaluate Visibility Impacts

See section V.C.

Step 6: Propose BART

For Line 1, EPA is proposing a limit of 1.2 lbs/MMBtu on a 30-day rolling average to be achieved within 1 year and 6 months after the effective date of this rule.

b. SO_2 BART Analysis

Step 1: Identify All Available Retrofit Control Technologies

Tilden identified the following SO_2 retrofit control technologies as available and applicable to pellet furnaces:

- Wet Walled Electrostatic Precipitator (WWESP),
- Wet Scrubbing,
- Dry Sorbent Injection (Dry Scrubbing Lime/Limestone Injection),
- Spray Dryer Absorption (SDA),
- Energy Efficiency Projects,
- Alternate Fuels, and
- Coal Processing.

Step 2: Eliminate Technically Infeasible Options

Tilden indicated that the potential fuel reductions and the commensurate emission reductions for future Energy Efficiency Projects cannot accurately be predicted without specific details. Therefore, due to the uncertainty and generalization of this category, energy efficiency projects were not subject to further analysis. Alternative Fuels were eliminated due to the uncertainty of alternative fuel costs, the potential of replacing one visibility pollutant for another, and Tilden's belief that BART does not intend to mandate a fuel switch. Using processed fuels at a taconite plant would require research, test burns, and extended trials to identify potential impacts on plant systems, including the furnaces, material handling, and emission control systems. Therefore, processed fuels are not considered commercially available and were not subject to further analysis by Tilden.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Tilden evaluated a WWESP and wet scrubber after its existing ESP, spray dry absorption, and dry sorbent injection as the remaining retrofit technologies it deemed to be available and technically feasible. Tilden estimated the control efficiency of WWESPs and a wet scrubber to be about 80 percent, dry sorbent injection to be 55 percent and spray dry absorption to be 90 percent. The following table illustrates the SO_2 emission reductions projected by Tilden technologies.

TABLE V–B.36—PROJECTED SO_2 EMISSION REDUCTIONS

[TPY]

SO_2 Control technology	Line 1
Spray Dry Absorption	1,037.8
Wet Walled ESP	922.5
Wet Scrubber	922.5
Dry Sorbent Injection	634.2

Step 4: Evaluate Impacts and Document Results

EPA has determined the cost-effectiveness of a 90 percent FGD scrubber to be $4500-$5500/ton using EPA's Air Pollution Control Cost Manual.

Step 5: Evaluate Visibility Impacts

See section V.C.

Step 6: Propose BART

For Line 1, EPA is proposing a limit of 5 ppmv or a 95 percent emission reduction, on a 30-day rolling average, to be achieved within 2 years after the effective date of this rule.

c. Non-Furnace BART Analysis

Process Boiler #1 and Process Boiler #2

Two natural gas and fuel oil fired process boilers (Process Boiler #1 and Process Boiler #2) require BART analysis. These boilers provide steam required to operate the taconite plant, as needed. The boilers are permitted to burn only natural gas and used oil.

SO_2 Analysis

Step 1: Identification of Available Retrofit Control Technologies

- Wet Walled Electrostatic Precipitator,
- Wet Scrubber,
- Dry Sorbent Injection (Dry Scrubbing Lime/Limestone Injection),
- Spray Dryer Absorption (SDA),
- Energy Efficiency Projects,
- Alternate Fuels, and
- Coal Processing.

Step 2: Elimination of Technically Infeasible Options

Tilden's process boilers cannot burn solid fuel, which eliminates coal processing. Due to the increased price of fuel, Tilden has already implemented energy efficiency projects. Each project carries its own fuel usage reductions and potentially emission reductions. Due to the uncertainty and generalization of this category, this option was eliminated. Similarly, Tilden eliminated alternative fuels because the environmental and economic benefits of such a change are uncertain, the limited fuel options available, and the fact that natural gas and oil are the fuels burned in the boilers.

Step 3: Evaluation of the Control Effectiveness of the Remaining Control Technologies

The following table illustrates the SO_2 emission reductions projected by Tilden with the technically feasible technologies.

TABLE V–B.37—PROJECTED ANNUAL SO_2 EMISSION REDUCTIONS

[TPY]

Control technology	Control efficiency (percent)	Emissions	Cost
None (Baseline)		0.25	
SDA	90	0.03	$38,403,000
Wet Scrubber	80	0.05	7,448,000
WWESP	80	0.05	15,733,000
Dry Scrubber	55	0.11	35,381,000

Step 4: Evaluate Impacts and Document Results

The two process boilers have very modest SO_2 emissions at 0.25 TPY. A wet scrubber would reduce emissions by 80 percent, but at an annual cost of about $1.5 million and a cost-effectiveness of $7,448,000 per ton.

Step 5: Evaluate Visibility Impacts

Visibility impacts were not modeled because additional reductions are not cost-effective.

Step 6: Propose BART

This BART analysis shows that adding a control device to control SO_2 emissions from the boilers would yield a very modest emission reduction at a multi-million dollar per ton cost. Thus, EPA is proposing retaining the 1.2% by weight sulfur content limit on the boilers when oil is burned.

NO_X Analysis

Step 1: Identification of Available Retrofit Control Technologies

- External Flue Gas Recirculation,
- Low-NO_X Burners,
- Low-NO_X Burners with Overfire Air,
- Induced Flue Gas Recirculation Burners,
- Low Excess Air,
- Reburning,
- Energy Efficiency Projects,
- Alternate Fuels,
- Non-Selective Catalytic Reduction,
- Selective Catalytic Reduction (SCR),
- Regenerative SCR,
- Selective Non-Catalytic Reduction, and
- Low Temperature Oxidation.

Step 2: Elimination of Technically Infeasible Options

External flue gas recirculation was eliminated as process boilers #1 and #2 do not have the capability of control at the burner tip, which is needed for this control technology. As noted in SO_2 determination, Tilden has already implemented energy efficiency projects. Each project carries its own fuel usage reductions and potentially emission reductions. Due to the uncertainty and generalization of this category, this option was eliminated. Similarly, Tilden eliminated alternative fuels because the environmental and economic benefits of such a change are uncertain and limited fuel options are available for the boilers. Operating a boiler with low excess air minimizes NO_X production during combustion. Tilden already operates process boiler #1 and #2 with low excess air. This option was thus not evaluated further as the benefit has already been achieved. Reburning is infeasible as the Tilden boilers do not burn solid fuel.

Regenerative SCR has only been used on wood-fired boilers. This technology has not been applied to liquid or natural gas fired boilers. Regenerative SCR is currently infeasible for the Tilden boilers. Low temperature oxidation is a post-combustion technology that uses an oxidant to oxide pollutants including NO_X. A scrubbing system is then used to remove the nitrates. Low temperature oxidation is an emerging technology that is currently infeasible as BART control on the Tilden boilers.

Step 3: Evaluation of the Control Effectiveness of the Remaining Control Technologies

The following table illustrates the NO_X emission reductions projected by Tilden with the technically feasible technologies.

TABLE V–B.38—PROJECTED ANNUAL NO_X EMISSION REDUCTIONS

[TPY]

Control technology	Control efficiency (percent)	Emissions	Cost
None (baseline)	....	79.23	....
SCR	80	15.85	$39,888
LNB/Flue Gas Recirculation	75	19.81	5,112
LNB/OFA	67	26.15	7,361
LNB	50	36.61	7,244
Selective Non-Catalytic Reduction	50	36.61	11,833

Step 4: Evaluate Impacts and Document Results

The two process boilers have modest NO_X emissions at about 80 TPY each. The combustion control technologies produce good control efficiencies at a lower cost compared to the post-combustion options. All the combustion control options have similar costs. A low NO_X burner coupled with flue gas recirculation produces a 59.42 TPY NO_X reduction per unit, the greatest control, at a cost of $5,122 per ton.

Step 5: Evaluate Visibility Impacts

Visibility impacts were not modeled because no additional reductions are required.

Step 6: Propose BART

Given that the control options are modest reductions in NO_X emission on a TPY basis, that modest reduction would need to provide a strong visibility improvement or be trivial in cost to justify a BART limit indicative of additional control. That is not the case for the process boilers. Thus, EPA is proposing the current good combustion practice as the NO_X emission restrictions for both Process Boiler #1 and Process Boiler #2.

Line 1 Dryer

The Line 1 Dryer includes a combustion box in which natural gas and used oil is burned as fuel. The flue gas from the combustion box flows into a rotary dryer that repeatedly tumbles wet taconite ore concentrate through the flue gas stream to reduce the amount of entrained moisture in the taconite ore concentrate. The particulate emissions from the dryer are controlled by cyclones and impingement scrubbers in series. The dryer is only permitted to use natural gas and used oil for fuel. The Line 1 Dryer has low emissions of SO_2 due to the low sulfur content of the permitted fuels. In addition, collateral SO_2 reductions occur within the existing impingement scrubbers, and therefore the existing scrubber is considered a low-efficiency SO_2 scrubber.

SO_2 Analysis

Step 1: Identification of Available Retrofit Control Technologies

- Wet Walled Electrostatic Precipitator,
- Wet Scrubber,
- Dry Sorbent Injection (Dry Scrubbing Lime/Limestone Injection),
- Spray Dryer Absorption (SDA),
- Energy Efficiency Projects,
- Alternate Fuels, and
- Coal Processing.

Step 2: Elimination of Technically Infeasible Options

The Line 1 Dryer cannot burn solid fuel, which eliminates coal processing. Tilden has already implemented energy efficiency projects on the dryer. Each project carries its own fuel usage reductions and potentially emission reductions. Due to the uncertainty and generalization of this category, this option was eliminated. Dry sorbent injection uses a fabric filter, ''baghouse,'' as part of the control system. The Line 1 Dryer exhaust is saturated with moisture. Such moisture would foul the baghouse. The same is true if the baghouse is placed following the wet scrubber into which the dryer currently exhausts. The dry sorbent injection system is thus technically infeasible for the Line 1 Dryer. The SDA system also uses a baghouse to capture the dry solids. The moisture in the dryer exhaust similarly creates problems with the baghouse. Thus, SDA is infeasible for Tilden's Line 1 Dryer. Alternative fuels are infeasible because the environmental and economic benefits of such a change are uncertain, the limited fuel options available, and the fact that natural gas and oil are the fuels used for the dryer.

Step 3: Evaluation of the Control Effectiveness of the Remaining Control Technologies

The following table illustrates the SO_2 emission reductions projected by Tilden with the technically feasible technologies.

TABLE V–B.39—PROJECTED ANNUAL SO_2 EMISSION REDUCTIONS

[TPY]

Control technology	Control efficiency (percent)	Emissions	Cost
None (baseline)	....	34.07	....
Wet Scrubber	80	6.81	$25,103
WWESP	80	6.81	52,432

Step 4: Evaluate Impacts and Document Results

The Line 1 Dryer has SO_2 emissions of 34.07 TPY. The moisture in the dryer exhaust limits the control options for this unit. A wet scrubber would reduce emissions by 27.26 TPY or 80 percent at an annual cost of about $25,000. The SO_2 emissions from this unit are already limited by fuel restrictions and the existing low-efficiency SO_2 scrubber.

Step 5: Evaluate Visibility Impacts

Visibility impacts were not modeled because no additional reductions are required.

Step 6: Propose BART

This BART analysis shows that adding a control device to control SO_2 emissions from the boilers would yield a modest emission reduction at a cost that could exceed $25,000 per ton. Thus, EPA is proposing retaining the fuel restriction of 1.5% by weight sulfur content limit when oil is burned.

NO_X Analysis

Step 1: Identification of Available Retrofit Control Technologies

- External Flue Gas Recirculation,
- Low-NO_X Burners (LNB),
- Low-NO_X Burners with Overfire Air,
- Induced Flue Gas Recirculation Burners,
- Low Excess Air,
- Reburning,
- Energy Efficiency Projects,
- Alternate Fuels,
- Non-Selective Catalytic Reduction,
- Selective Catalytic Reduction (SCR),
- Regenerative SCR,
- Selective Non-Catalytic Reduction, and
- Low Temperature Oxidation.

Step 2: Elimination of Technically Infeasible Options

External flue gas recirculation was eliminated as the configuration of the Line 1 Dryer burner does have the capability of control at the burner tip, which is needed for this control technology. As noted in the SO_2 determination, Tilden has already implemented energy efficiency projects. Each project carries its own fuel usage reductions and potentially emission reductions. Due to the uncertainty and generalization of this category, this option was eliminated. Similarly, Tilden eliminated alternative fuels because the environmental and economic benefits of such a change are uncertain and limited fuel options are available for the boilers. Induced flue gas recirculation burner technology is infeasible for the Line 1 Dryer. Operating a boiler with low excess air minimizes NO_X production during combustion. Similar to process boiler #1 and #2, the dryer is already operated with low excess air. This option was thus not evaluated further as the benefit has already been achieved. Reburning is infeasible as the Line 1 Dryer does not burn solid fuel.

Regenerative SCR has only been used on wood-fired boilers. This technology has not been applied to liquid or natural gas fired burners. Regenerative SCR is currently infeasible for the Line 1 Dryer. Low temperature oxidation is a post-combustion technology that uses an oxidant to oxide pollutants including NO_X. A scrubbing system is then used to remove the nitrates. Low temperature oxidation has not been applied on a taconite dryer. It is currently considered infeasible as BART control option on the dryer unit.

Step 3: Evaluation of the Control Effectiveness of the Remaining Control Technologies

The following table illustrates the NO_X emission reductions projected by Tilden with the technically feasible technologies.

TABLE V–B.40—PROJECTED ANNUAL NO_X EMISSION REDUCTIONS

[TPY]

Control technology	Control efficiency percent	Emissions	Cost
None (baseline)	....	15.1	....
SCR	80	3.02	$83,472
LNB/Flue Gas Recirculation	75	3.77	11,891
LNB/OFA	67	4.98	11,535
LNB	50	7.55	8,090
Selective Non-Catalytic Reduction	50	7.55	36,949

Step 4: Evaluate Impacts and Document Results

The Line 1 Dryer has modest NO_X emissions of 15.1 TPY. The combustion control technologies produce good control efficiencies at a lower cost compared to the post-combustion options. A low NO_X burner produces a 7.55 TPY NO_X reduction at a cost of $8,090 per ton.

Step 5: Evaluate Visibility Impacts

Visibility impacts were not modeled because no additional reductions are required.

Step 6: Propose BART

Given that the control options are modest reductions in NO_X emission on a TPY basis, that modest reduction would need to provide a strong visibility improvement or be trivial in cost to justify a BART limit indicative of additional control. That is not the case for the Tilden Line 1 Dryer. Thus, EPA is proposing the current good combustion practice as the NO_X emission restrictions for the Line 1 Dryer.

C. Bart Visibility Improvement Analysis

1. Background

There are five factors considered in a case-by-case BART analysis once a source has been determined to be subject to BART. The first four pertain to identifying and evaluating available control technologies based on technical feasibility, emission control levels, control cost effectiveness, and energy and non-air quality environmental impacts. The first four factors have been discussed elsewhere in this proposed rulemaking. The fifth factor covers the visibility improvements resulting from the BART emission controls. The ''Final Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations'' document discussed in EPA's ''Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations'' final rule (70 FR 39104) (Regional Haze Rule) addresses application of the fifth factor. Although it is a required element of a BART analysis, there is substantial flexibility allowed in determining how the visibility impacts factor is implemented and how much weight and significance is assigned to this factor.

2. Visibility Improvement Modeling

EPA is relying on visibility improvement modeling conducted previously by the MPCA and documented in MPCA's document ''Visibility Improvement Analysis of Controls Implemented Due to BART Determinations on Emission Units

Subject-to-BART,'' October 23, 2009, and also detailed in ''Appendix 9.5: BART Visibility Modeling,'' included as part of MPCA's December 2009 regional haze SIP submittal.

The visibility improvement modeling conducted by MPCA examined the degree of visibility improvement in the Class I areas of Voyageurs National Park (Voyageurs), Boundary Waters Canoe Area Wilderness (Boundary Waters), and Isle Royale National Park (Isle Royale), determined to be impacted by NO_X and SO_2 sources and State-estimated BART emission reductions covered in MPCA's BART analysis. The sources investigated by the MPCA, and of interest in our BART proposed rule, were Minnesota Power-Boswell Energy Center, Minnesota Power-Taconite Harbor, Northshore Mining-Silver Bay, and United Taconite-Fairlane Plant (now named United Taconite). These sources are located in the same general area as the sources addressed by BART determinations in this proposed rule. The discussion below uses MPCA's emissions data and modeled visibility impact data to derive visibility impact ratios as a function of changes in emissions of NO_X and SO_2 at MPCA-modeled facilities. These visibility-emissions ratios were then applied to the BART-based emission changes for the sources subject to this BART rule to derive possible visibility impacts.

The modeling system used by MPCA for BART visibility analyses is discussed in detail in ''Technical Support Document of the Minnesota State Implementation Plan for Regional Haze,'' May 2009, and in Appendix 9.5 of MPCA's December 2009 regional haze SIP submittal. The system utilizes:

- Comprehensive Air Quality Model (CAMx) as the photochemical modeling tool,
- The Pennsylvania State University/National Center for Atmospheric Research (PSU/NCAR) Mesoscale Meteorological Model (MM5) as the meteorological model,
- Emissions Modeling System (EMS–2003) as the emissions model. The base period modeling for the MPCA work included emissions from 2002.

The Particulate Source Apportionment Technology (PSAT) tool in CAMx, along with the new IMPROVE visibility extinction formula (to calculate light extinction resulting from monitored or modeled nitrate, sulfate, and $PM_{2.5}$ concentrations and assumed relative humidity (pH) extinction factors) was used to evaluate air quality/visibility impacts from the individual sources. The modeling domain featured a 36 kilometer resolution grid extending over the eastern two-thirds of the United States, and encompassed a smaller 12 kilometer resolution nested modeling domain, with Plume-in-Grid (PiG) concentration estimates, covering all of Minnesota. Visibility was assessed in each of the three Class I areas using 15 modeling receptors in Voyageurs, 62 modeling receptors in Boundary Waters, and 15 modeling receptors in Isle Royale.

The MPCA modeling examined the impact of the BART controls on both the number of days (ΔDays) with a change (increase) in deciview [12] above 0.5 (ΔDays > 0.5) and the 98th percentile change in deciview values (Δdv).

Only one of the sources examined by MPCA and addressed here included emission changes from furnaces at a taconite facility. This facility, United Taconite, is located in St. Louis County, Minnesota, roughly 60–80 kilometers from the Class I areas in Northern Minnesota, Voyageurs and Boundary Waters, and approximately 120 kilometers from Isle Royale. The MPCA modeling compared the 2002 actual emissions used in Minnesota's regional haze SIP modeling to the emissions assumed based on the state-determined BART emission controls with corresponding modeled emission reductions for NO_X and sulfur dioxide. Modeling was conducted for the meteorological years of 2002 and 2005. The results are shown in MPCA's BART analysis in terms of the change in Δdv and ΔDays for $PM_{2.5}$,[13] sulfate (SO_4), and nitrate (NO_3).

The MPCA visibility modeling documentation details visibility due to the implementation of BART controls for all of the sources considered by the State. However, the FIP covered by this proposed rule only addresses BART control of furnaces located at taconite facilities. Therefore, we have given special attention to the visibility modeling results for the one taconite facility addressed in detail in MPCA's BART visibility modeling discussion, United Taconite.

The detailed modeling information for United Taconite, as presented in MPCA's visibility modeling documentation is duplicated below:

TABLE V–C.1—EMISSIONS (UNITED TACONITE)

[Actual 2002 Emissions in Tons Modeled]

Description	Stack ID	NO_X	SO_2	$PM_{2.5}$	PM_{10}
Facility Elevated Stack Total*		1,765	3,222	183	473.
BART Unit Stack Total	SV049	1,764	3,222	13	367.
BART Unit Stack Percent of Facility Total Emissions*.		100%	100%	7%	78%.
BART Unit Stack Total with BART Controls.		1,764	1,385	No BART Controls.	
BART Unit Stack Emission Reduction due to BART Controls.		0%	−57%		

* Facility total only accounts for emissions from elevated stacks. The criteria for elevated stacks is those with a plume rise of 50 meters or more as calculated by the emissions model.

[12] The deciview is a visual index designed to be linear with respect to perceived visibility changes over its entire range in a way that is analogous to the decibel index for sound. The deciview scale is zero for pristine conditions and increases as visibility degrades.

[13] All fine particulates, including sulfates, nitrates, and other fine particulate components.

TABLES V–C.2 THROUGH V–C.4—NUMBER OF DAYS WITH VISIBILITY DEGRADATION > 0.5 DV AND 98TH PERCENTILE DECIVIEW IMPACT VALUES (UNITED TACONITE)

Parameter	Met Year	Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
		Base	BART	Change	Base	BART	Change	Base	BART	Change
$PM_{2.5}$										
Days > 0.5 dv	2002	59	44	−15	32	20	−12	8	1	−7
	2005	40	24	−16	22	11	−11	3	2	−1
	'02 & 05	99	68	−31	54	31	−23	11	3	−8
98th Percentile dv	2002	3.0	1.7	−1.3	1.8	0.8	−0.9	0.6	0.3	−0.3
	2005	1.5	1.1	−0.4	1.0	0.7	−0.3	0.4	0.2	−0.2
	'02 & 05	3.1	1.9	−1.2	1.9	1.1	−0.8	0.6	0.3	−0.3
SO_4										
Days > 0.5 dv	2002	47	29	−18	29	17	−12	8	0	−8
	2005	32	15	−17	20	6	−14	3	0	−3
	'02 & 05	79	44	−35	49	23	−26	11	0	−11
98th Percentile dv	2002	3.0	1.6	−1.4	1.7	0.8	−0.9	0.5	0.3	−0.3
	2005	1.4	0.7	−0.7	0.9	0.5	−0.4	0.4	0.2	−0.2
	'02 & 05	3.0	1.7	−1.3	1.9	1.0	−0.9	0.6	0.3	−0.3
NO_3										
Days > 0.5 dv	2002	5	8	3	0	1	1	0	0	0
	2005	7	11	4	1	4	3	0	1	1
	'02 & 05	12	19	7	1	5	4	0	1	1
98th Percentile dv	2002	0.4	0.5	0.1	0.1	0.1	0.0	0.1	0.1	0.0
	2005	0.5	0.6	0.1	0.2	0.2	0.1	0.1	0.1	0.0
	'02 & 05	0.6	0.7	0.2	0.2	0.3	0.1	0.1	0.1	0.0

As the tables indicate, while there were no NO_X emission reductions associated with the State's assessed BART emission controls at United Taconite, the SO_2 emission reductions resulted in reductions in the number of days with deciview changes above 0.5 at all three Class I areas, including ΔDays reductions in excess of 10 at Boundary Waters and Voyageurs. Additionally, the 98th percentile deciview values were reduced (Δdv) for each Class I area. These improvements were associated with a 1,837 tons per year reduction in SO_2 emissions at this facility. Because there were no reductions in NO_X at United Taconite associated with the State-determined BART emission controls, the improvement in visibility due to SO_2 emission reductions are offset by visibility degradation resulting from small nitrate increases. According to MPCA, the reduced levels of SO_2 downwind from United Taconite would allow more ammonia in the atmosphere to become available to react with NO_X to form ammonium nitrate, a compound that can contribute to visibility impairment.

The modeled SO_2 emission reduction and visibility impacts for $PM_{2.5}$ can be used to derive visibility impact/emission reduction ratios at each of the Class I areas. Table V–C.5 presents the modeled emission reductions and derived visibility impact ratios for fine particulates for United Taconite at each of the Class I areas. Note that the $\Delta DaysPM_{2.5}$ numbers used in this table (and in subsequent tables) are annual averages. Also note that, in this table and in subsequent tables, we have considered Δdv and ΔDays values for $PM_{2.5}$, which include the visibility impacts of both nitrates and sulfates, as well as other fine particulate components.

TABLE V–C.5—BART NO_X AND SO_2 EMISSION REDUCTIONS AND MODELED VISIBILITY IMPACT/EMISSION REDUCTION RATIOS FOR FINE PARTICULATES AT CLASS I AREAS FOR UNITED TACONITE

Parameter	Boundary Waters	Voyageurs	Isle Royale
NO_X Emissions Decrease	0 tons/year		
SO_2 Emissions Decrease (ΔSO_2)	1,837 tons/year		
$\Delta dv_{PM2.5}$	−1.2	−0.8	−0.3
$\Delta dv_{PM2.5}/\Delta SO_2$	−0.00065	−0.00043	−0.000098
$\Delta Days_{PM2.5}$	−10	−8	−3
$\Delta Days_{PM2.5}/\Delta SO_2$	−0.0054	−0.0044	−0.0016

Other sources addressed in MPCA's modeling study would reduce both NO_X and SO_2 emissions through the implementation of BART emission controls. Three examples of sources considered for BART controls are located near the Class I areas of interest, Minnesota Power-Taconite Harbor, Minnesota Power-Boswell Energy Center, and Northshore Mining-Silver Bay. Both Minnesota Power-Taconite Harbor and Northshore Mining-Silver Bar are located near Lake Superior and east of the Minnesota taconite facilities considered in this FIP proposed rule. Minnesota Power-Boswell Energy Center is located in northern Minnesota and west of the area encompassing the Minnesota taconite facilities considered in this FIP proposed rule. All three of these source facilities addressed by the MPCA would have both NO_X emission reductions and SO_2 emission reductions under MPCA's-determined BART emission controls.

We have used the State's modeled BART emission reductions and visibility impacts for fine particulates to determine the sensitivity of visibility parameters for the Class I areas to changes in NO_X and SO_2 emissions. The modeled emission changes, Δdv, and ΔDays values used to calculate the sensitivity of visibility parameters to emission changes were taken from Appendix 9.5 of Minnesota's December 2009 SIP revision submittal.

Table V–C.6 presents the modeled emission reductions and derived visibility impact ratios for Minnesota Power-Boswell Energy Center at each of the Class I areas.

TABLE V–C.6—BART NO_X AND SO_2 EMISSION REDUCTIONS AND MODELED VISIBILITY IMPACT/EMISSION REDUCTION RATIOS FOR FINE PARTICULATES AT CLASS I AREAS FOR MINNESOTA POWER-BOSWELL ENERGY CENTER

Parameter	Boundary Waters	Voyageur	Isle Royale
NO_X Emissions Decrease (ΔNO_X)	3,978 tons/year		
SO_2 Emissions Decrease (ΔSO_2)	11,952 tons/year		
$\Delta dv_{PM2.5}$	−2.1	−2.0	−0.9
$\Delta dv_{PM2.5}/\Delta NO_X$	−0.00053	−0.00050	−0.00023
$\Delta dv_{PM2.5}/\Delta SO_2$	−0.00018	−0.00017	−0.000075
$\Delta Days_{PM2.5}$	−30	−21	−15
$\Delta Days_{PM2.5}/\Delta NO_X$	−0.0075	−0.0053	−0.0038
$\Delta Days_{PM2.5}/\Delta SO_2$	−0.0025	−0.0018	−0.0013

Table V–C.7 presents the modeled emission reductions and derived visibility impact ratios for fine particulates for Minnesota Power-Taconite Harbor at each of the Class I areas.

TABLE V–C.7—BART NO_X AND SO_2 EMISSION REDUCTIONS AND MODELED VISIBILITY IMPACT/EMISSION REDUCTION RATIOS FOR FINE PARTICULATES AT CLASS I AREAS FOR MINNESOTA POWER-TACONITE HARBOR

Parameter	Boundary Waters	Voyageur	Isle Royale
NO_X Emissions Decrease (ΔNO_X)	399 tons/year		
SO_2 Emissions Decrease (ΔSO_2)	566 tons/year		
$\Delta dv_{PM2.5}$	−0.4	−0.1	−0.3
$\Delta dv_{PM2.5}/\Delta NO_X$	−0.0010	−0.00025	−0.00075
$\Delta dv_{PM2.5}/\Delta SO_2$	−0.00071	−0.00018	−0.00053
$\Delta Days_{PM2.5}$	−4	−2	−3
$\Delta Days_{PM2.5}/\Delta NO_X$	−0.010	−0.0050	−0.0075
$\Delta Days_{PM2.5}/\Delta SO_2$	−0.0071	−0.0035	−0.0053

Table V–C.8 presents the modeled emission reductions and derived visibility impact ratios for fine particulates for Northshore Mining-Silver Bay at each of the Class I areas.

TABLE V–C.8. BART NO_X AND SO_2 EMISSION REDUCTIONS AND MODELED VISIBILITY IMPACT/EMISSION REDUCTION RATIOS FOR FINE PARTICULATES AT CLASS I AREAS FOR NORTHSHORE MINING-SILVER BAY

Parameter	Boundary Waters	Voyageur	Isle Royale
NO_X Emissions Decrease (ΔNO_X)	678 tons/year		
SO_2 Emissions Decrease (ΔSO_2)	444 tons/year		
$\Delta dv_{PM2.5}$	−0.2	−0.1	−0.2
$\Delta dv_{PM2.5}/\Delta NO_X$	−0.00029	−0.00023	−0.00029
$\Delta dv_{PM2.5}/\Delta SO_2$	−0.00045	−0.00023	−0.00045
$\Delta Days_{PM2.5}$	−5	−1	−3
$\Delta Days_{PM2.5}/\Delta NO_X$	−0.0074	−0.0015	−0.0044
$\Delta Days_{PM2.5}/\Delta SO_2$	−0.011	−0.0023	−0.0068

The above visibility factor/emission change ratio data show significant variation from source-to-source and between impacted Class I areas. This variation is caused by differences in the relative locations of the sources (relative to the locations of the Class I areas), variations in background sources, variations in transport patterns on high haze factors, and other factors that we cannot assess without detailed modeling of the visibility impacts for the sources as a function of pollutant emission type. The above data, however, can be used to approximate possible visibility impacts due to the production of fine particulates downwind of the taconite facilities addressed in this FIP proposed rule. To estimate the visibility impacts, we have averaged the fine particulate Δdv and ΔDays emission change ratios for NO_X and SO_2 for the four sources documented in Tables V–C.5 through V–C.8 above for each of the Class I areas. These averaged visibility factor/emission change ratios are summarized in Table V–C.9.

TABLE V–C.9—AVERAGED VISIBILITY IMPACT/EMISSION CHANGE RATIOS FOR ANALYZED/IMPACTED CLASS I AREAS

Parameter ratio	Boundary Waters	Voyageurs	Isle Royale
$\Delta dv_{PM2.5}/\Delta NO_X$	−0.00061	−0.00033	−0.00040
$\Delta dv_{PM2.5}/\Delta SO_2$	−0.00050	−0.00025	−0.00029
$\Delta Days/\Delta NO_X$	−0.0083	−0.004	−0.005
$\Delta Days/\Delta SO_2$	−0.0067	−0.0030	−0.0033

To calculate the visibility impacts for the Minnesota source facilities covered by this FIP proposed rule, we multiplied the total estimated BART NO_X and SO_2 emission reductions for each subject facility by the appropriate visibility factor/emission change ratios in Table V–C.9 and combined the results to estimate the total visibility impacts that would result from the reduction of $PM_{2.5}$ concentrations. The estimated visibility factor changes by Class I area for each of the subject taconite facilities in Minnesota are given in Tables V–C.10 through V–C.15.

TABLE V–C.10—ESTIMATED EMISSION REDUCTIONS AND RESULTING CHANGES IN VISIBILITY FACTORS FOR ARCELORMITTAL

Visibility factor or pollutant emissions reduction	Boundary Waters	Voyageur	Isle Royale
NO_X Emissions Reduction	2,859 tons/year		
Δdv	−1.7	−0.9	−1.1
ΔDays > 0.5 dv	−24	−11	−18

TABLE V–C.11—ESTIMATED EMISSION REDUCTIONS AND RESULTING CHANGES IN VISIBILITY FACTORS FOR HIBBING TACONITE

Visibility factor or pollutant emissions reduction	Boundary Waters	Voyageur	Isle Royale
NO_X Emissions Reduction	5,259 tons/year		
Δdv	−3.2	−1.7	−2.1
ΔDays > 0.5 dv	−44	−21	−26

TABLE V–C.12—ESTIMATED EMISSION REDUCTIONS AND RESULTING CHANGES IN VISIBILITY FACTORS FOR NORTHSHORE MINING

Visibility factor or pollutant emissions reduction	Boundary Waters	Voyageur	Isle Royale
NO_X Emissions Reduction	926 tons/year		
Δdv	−0.6	−0.3	−0.4
ΔDays > 0.5 dv	−8	−4	−5

TABLE V–C.13—ESTIMATED EMISSION REDUCTIONS AND RESULTING CHANGES IN VISIBILITY FACTORS FOR UNITED TACONITE

Visibility factor or pollutant emissions reduction	Boundary Waters	Voyageur	Isle Royale
NO_X Emissions Reduction	3,208 tons/year		
SO_2 Emissions Reduction	3,639 tons/year		
Δdv	−1.9	−0.99	−1.16
ΔDays > 0.5 dv	−29	−12	−14

TABLE V–C.14—ESTIMATED EMISSION REDUCTIONS AND RESULTING CHANGES IN VISIBILITY FACTORS FOR U.S. STEEL-KEETAC

Visibility factor or pollutant emissions reduction	Boundary Waters	Voyageur	Isle Royale
NO_X Emissions Reduction	2,908 tons/year		
Δdv	−1.8	−1.0	−1.2
ΔDays > 0.5 dv	−28	−12	−15

TABLE V–C.15—ESTIMATED EMISSION REDUCTIONS AND RESULTING CHANGES IN VISIBILITY FACTORS FOR U.S. STEEL-MINNTAC

Visibility factor or pollutant emissions reduction	Boundary Waters	Voyageur	Isle Royale
NO_X Emissions Reduction	6,077 tons/year		
SO_2 Emissions Reduction	980 tons/year		
Δdv	−3.3	−1.7	−2.1
ΔDays > 0.5 dv	−45	−21	−26

From Tables V–C.10 through V–C.15, it can be seen that the BART emission controls determined for the Minnesota taconite facilities have the potential to produce significant improvements in visibility at all three Class I areas.

The State of Michigan has provided some emissions, air quality, and visibility modeling data for Tilden that may be used to provide an estimate of the visibility impact for the implementation of BART emission controls at Tilden. The Michigan SIP submittal for regional haze, dated October 2010, does include BART assessment data for Tilden, and Tilden NO_X and SO_2 emissions have been modeled, along with the emissions for many other source facilities to derive visibility impacts at two Class I areas, Isle Royale National Park and Seney National Wildlife Refuge (Seney). Maximum visibility impacts have been determined for each modeled source facility at the two Class I areas. To model the visibility impacts, air quality impacts were estimated for each pollutant emitted using the CALPUFF model for 2000–2004 emissions. The modeled air quality impacts were entered through the IMPROVE visible extinction equation to calculate the visual extinction coefficient for each modeled facility. The facility-specific visual extinction coefficients were used to calculate the facility-specific visibility impact in deciviews. The modeling results for Tilden are discussed in Appendices 9H: ''Tilden Mining Company BART Technical Analysis,'' 10E: ''Calpuff Modeling, Q/D And Visibility For Seney,'' and 10D: ''Calpuff Modeling, Q/D And Visibility For Isle Royale'' for Michigan's October 2010 haze SIP submittal.

The visibility modeling for Tilden shows that it contributed 0.674 deciviews, with 41 days exceeding 0.5 deciviews from 2002–2004, at Isle Royale National Park. Over 96 percent of the modeled SO_2 and NO_X emissions from Tilden were from its indurating furnace. Michigan's post control modeling scenario no. 3 reflects both 80 percent NO_X and SO_2 emission reductions, which are similar to the controls being proposed as BART and these reductions result in a 0.501 deciview improvement at IRNP. The visibility impact resulting from 70 percent reduction for both SO_2 and NO_X can be approximated by taking ⅞ of 0.501, which results in an improvement of 0.438 deciviews.

In conclusion, the available information indicates that control of emissions from taconite plants in Minnesota and Michigan can be expected to yield significant benefits in reducing visibility impairment in the Class I areas in the two states. Extrapolating from modeling results provided by the two states, the impacts of candidate control options range from about 0.5 deciviews to 3.3 deciviews, with between about 10 and about 130 fewer days over three years with impacts above 0.5 deciviews. While these estimates are not based on direct modeling of the scenarios of interest, the scenarios being addressed here are sufficiently similar to the scenarios addressed in state modeling that EPA considers these estimates to provide adequate indication of the benefits of these controls. Each BART determination is a function of consideration of visibility improvements and other factors for the individual unit, but in general EPA's assessment of visibility impacts finds that technically feasible controls that are available at a reasonable cost for taconite plants can be expected to provide a visibility benefit that makes those controls warranted.

D. Testing and Monitoring, Recordkeeping, and Reporting Requirements.

To ensure compliance with the proposed BART limits, EPA has proposed testing and monitoring requirements for the taconite plants subject to this rule. The proposed FIP also includes recordkeeping and reporting requirements for these sources.

VI. Proposed Action

We are proposing to approve the following NO_X and SO_2 BART limits for the taconite plants in Minnesota and Michigan that are subject to BART.

U.S. Steel Minntac

NO_X—A limit of 1.2 lbs/MMBtu on a 30-day rolling average for all lines to be achieved as follows: 1 Year after the effective date of this rule for line 6, 2 years after the effective date for Line 7, 3 years after the effective date for Line 4, 4 years after the effective date for Line 5, and 4 years and 11 months after the effective date for Line 3.

SO_2—71.3 lbs SO_2/hr for Line 3, 56.1 lbs SO_2/hr for Line 4, 67.9 lbs SO_2/hr for Line 5, 64.5 lbs SO_2/hr for Line 6, and 67.1 lbs SO_2/hr for Line 7. Compliance is to be achieved with these limits within three months after the effective date of this rule. These limits are measured on a 30-day rolling average.

Northshore Mining

NO_X—A limit of 1.2 lbs/MMBtu on a 30-day rolling average for all lines to be achieved as follows: 1 Year and 6 months after the effective date for Line 11 and 2 years and 6 months after the effective date for Line 12. An emission limit of 0.085 lb/hr as a 30-day rolling average shall apply to each of the boilers, Process Boiler #1 and Process Boiler #2, beginning no later than 5 years from the effective date of this rule. The process boiler limits shall apply at all times a unit is operating.

SO_2—A limit of 16.3 lbs SO_2/hr for Furnace 11 and 17.1 lbs SO_2/hr for Furnace 12, measured on a 30-day rolling average. These limits do not apply when the subject emissions unit is burning fuel oil. An 80.0 percent SO_2 reduction requirement is also required for the stacks serving Furnaces 11 and 12. Compliance is to be achieved with these limits within 6 months after the effective date of this rule.

United Taconite

NO_X—A limit of 1.2 lbs/MMBtu on a 30-day rolling average for all lines to be achieved as follows: 1 Year and 6 months after the effective date of this rule for Line 2 and 2 years and 6 months after the effective date for Line 1.

SO_2—A limit of 5 ppmv, on a 30-day rolling average, to be achieved within 2 years after the effective date of this rule for Line 2 and 4 years after the effective date of this rule for Line 1. As an alternative, the owner or operator may meet a 95 percent SO_2 removal efficiency limit, on a 30-day rolling average, for Line 1, Line 2, or both lines instead of complying with the 5 ppmv limit. The owner or operator shall comply with the limit within 2 years after the effective date of this rule for Line 2 and within 4 years after the effective date of this rule for Line 1.

ArcelorMittal

NO_X—A limit of 1.2 lbs/MMBtu on a 30-day rolling average to be achieved within 1 year and 6 months after the effective date of this rule for its indurating furnace.

SO_2—23.0 lbs SO_2/hr, on a 30-day rolling average, for its indurating furnace. This limit does not apply when the subject source is burning fuel oil. Compliance is to be achieved with this limit within three months after the effective date of this rule.

Hibbing Taconite

NO_X—A limit of 1.2 lbs/MMBtu on a 30-day rolling average for all lines to be achieved as follows: 1 Year and 6 months after the effective date for Line 1, 2 years and 6 months after the effective date for Line 3, and 3 years and 6 months for Line 2.

SO_2—A limit of 56.0 lbs SO_2/hr for Line 1, 63.0 lbs SO_2/hr for Line 2, and 64.0 lbs/hr for Line 3, measured on a 30-day rolling average. These limits do not apply when the subject source is burning fuel oil. Compliance is to be achieved with these limits within 3 months after the effective date of this rule.

U.S. Steel Keewatin

NO_X—A limit of 1.2 lbs/MMBtu on a 30-day rolling average to be achieved within 1 year and 6 months after the effective date of this rule for its Phase II furnace.

SO_2—Keetac's existing recirculating lime scrubber satisfies BART. This scrubber is subject to a 57 percent SO_2 removal efficiency and a limit, based on CEMS data, of 225 lbs SO_2 per hour on a 30-day rolling average. This scrubber is also required to operate at or above a pH of 7.5. Compliance is to be achieved with these limits within 90 days after the effective date of this rule.

Tilden

NO_X—A limit of 1.2 lbs/MMBtu on a 30-day rolling average to be achieved within 1 year and 6 months after the effective date of this rule for its Line 1.

SO_2—A limit of 5 ppmv, on a 30-day rolling average, to be achieved within 2 years after the effective date of this rule for Line 1. As an alternative, the owner or operator may meet a 95 percent SO_2 removal efficiency limit, on a 30-day rolling average, for Line 1 instead of complying with the 5 ppmv limit. The owner or operator shall comply with the limit within 2 years after the effective date of this rule. An emission limit of 1.20 percent sulfur content by weight shall apply to fuel combusted in Process Boiler #1 (EUBOILER1) and Process Boiler #2 (EUBOILER2) beginning 3 months from the effective date of this rule. An emission limit of 1.50 percent sulfur content by weight shall apply to fuel combusted in the Line 1 Dryer (EUDRYER1) beginning 3 months from the effective date of this rule.

VII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

This proposed action is not a ''significant regulatory action'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011). As discussed in detail in section C below, the proposed FIP applies to only six sources. It is therefore not a rule of general applicability.

B. Paperwork Reduction Act

This proposed action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* Under the Paperwork Reduction Act, a ''collection of information'' is defined as a requirement for ''answers to * * * identical reporting or recordkeeping requirements imposed on ten or more persons * * * .'' 44 U.S.C. 3502(3)(A). Because the proposed FIP applies to just six facilities, the Paperwork Reduction Act does not apply. *See* 5 CFR 1320(c).

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid Office of Management and Budget (OMB) control number. The OMB control numbers for our regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's proposed rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-forprofit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this proposed action on small entities, I certify that this proposed action will not have a significant economic impact on a substantial number of small entities. EPA's proposal adds additional controls to certain sources. The Regional Haze FIP that EPA is proposing for purposes of the regional haze program consists of imposing Federal control requirements to meet the BART requirement for NO_X and SO_2 emissions on specific units at six sources in Minnesota and one in Michigan. The net result of the FIP action is that EPA is proposing emission controls on the indurating furnaces at seven taconite facilities and none of these sources are owned by small entities, and therefore are not small entities.

D. Unfunded Mandates Reform Act (UMRA)

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more (adjusted for inflation) in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 of UMRA do not apply when they are inconsistent with applicable law. Moreover, section 205 of UMRA allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

Under Title II of UMRA, EPA has determined that this proposed rule does not contain a federal mandate that may result in expenditures that exceed the inflation-adjusted UMRA threshold of $100 million by State, local, or Tribal governments or the private sector in any one year. In addition, this proposed rule does not contain a significant federal intergovernmental mandate as described by section 203 of UMRA nor does it contain any regulatory requirements that might significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

Federalism (64 FR 43255, August 10, 1999) revokes and replaces Executive Orders 12612 (Federalism) and 12875 (Enhancing the Intergovernmental Partnership). Executive Order 13132 requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.'' Under Executive Order 13132, EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the proposed regulation. EPA also may not issue a regulation that has federalism implications and that preempts State law unless the Agency consults with State and local officials early in the process of developing the proposed regulation.

This rule will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132, because it merely addresses the State not fully meeting its obligation to prohibit emissions from interfering with other states measures to protect visibility established in the CAA. Thus, Executive Order 13132 does not apply to this action. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed rule from State and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled *Consultation and Coordination with Indian Tribal Governments* (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' This proposed rule does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments. Thus, Executive Order 13175 does not apply to this rule. However, EPA did discuss this action in a June 28 conference call with the Michigan and Minnesota Tribes.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045: *Protection of Children from Environmental Health Risks and Safety Risks* (62 FR 19885, April 23, 1997), applies to any rule that: (1) Is determined to be economically significant as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children. EPA interprets EO 13045 as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it implements specific standards established by Congress in statutes. However, to the extent this proposed rule will limit emissions of NO_X, SO_2, and PM, the rule will have a beneficial effect on children's health by reducing air pollution.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12 of the National Technology Transfer and Advancement Act (NTTAA) of 1995 requires federal agencies to evaluate existing technical standards when developing a new regulation. To comply with NTTAA, EPA must consider and use ''voluntary consensus standards'' (VCS) if available and applicable when developing programs and policies unless doing so would be inconsistent with applicable law or otherwise impractical.

The EPA believes that VCS are inapplicable to this action. Today's action does not require the public to perform activities conducive to the use of VCS.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994), establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

We have determined that this proposed rule, if finalized, will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

Dated: July 13, 2012.

Susan Hedman,

Regional Administrator, Region 5.

40 CFR part 52, as proposed to be amended at 77 FR 46912, August 6, 2012, is proposed to be amended as follows:

PART 52—[AMENDED]

1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

2. Section 52.1183 is amended by adding paragraphs (j), (k), (l), (m), and (n) to read as follows:

§ 52.1183 Visibility protection.

* * *

(j) The requirements of section 169A of the Clean Air Act are not met because the regional haze plan submitted by the state on November 5, 2010, does not meet the requirements of 40 CFR 51.308(e) with respect to NO_X and SO_2 emissions from Tilden Mining Company L.C. of Ishpeming, Michigan. The requirements for this facility are satisfied by complying with § 52.1183(k–n).

(k)(1) NO_X Emission Limits. An emission limit of 1.20 lb NO_X/MMBtu at 7 percent oxygen, based on a 30-day rolling average, shall apply to the indurating furnace, Grate Kiln Line 1 (EUKILN1), beginning 1 year and 6 months from the effective date of this rule.

(2) SO_2 Emission Limits. A fuel sulfur content limit of no greater than 1.20 percent sulfur content by weight shall apply to fuel combusted in Process Boiler #1 (EUBOILER1) and Process Boiler #2 (EUBOILER2) beginning 3 months from the effective date of this rule. A fuel sulfur content limit of no greater than 1.50 percent sulfur content by weight shall apply to fuel combusted in the Line 1 Dryer (EUDRYER1) beginning 3 months from the effective date of this rule.

(3) The owner or operator of the facility must comply with either (3)(i) or (3)(ii) for the Grate Kiln Line 1 (EUKILN1) beginning 2 years from the effective date of this rule. The selection must be identified in the initial notification of compliance required by this rule.

(i) An emission limit of 5 ppmv SO_2 at 7 percent oxygen, based on a 30-day rolling average, shall apply to the Grate Kiln Line 1 (EUKILN1).

(ii) A 95.0 percent or greater SO_2 removal efficiency by the wet/dry FGD, based on a 30-day rolling average, shall apply to the Grate Kiln Line 1 (EUKILN1).

(l) Testing and Monitoring.

(1) No later than the compliance date of this regulation, the owner or operator shall install, certify, calibrate, maintain and operate a Continuous Emissions Monitoring System (CEMS) for NO_X on Tilden Mining Company unit EUKILN1 in accordance with 40 CFR63.8, and Appendices B and F of Part 60. The owner or operator shall install, certify, calibrate, maintain and operate a continuous diluent monitor (O_2 or CO_2) and continuous flow rate monitor on Tilden Mining Company unit EUKILN1 to allow conversion of the NO_X concentration to units of the standard (lbs/MMBtu). Compliance with the emission limits for NO_X shall be determined using data from the CEMS corrected to 7 percent oxygen.

(2) No later than the compliance date of this regulation, the owner or operator shall install, certify, calibrate, maintain and operate one or more CEMS for SO_2 on Tilden Mining Company unit EUKILN1 in accordance with 40 CFR 63.8, and Appendices B and F of Part 60. The owner or operator shall install, certify, calibrate, maintain and operate one or more continuous diluent monitor(s) (O_2 or CO_2) and continuous flow rate monitor(s) on Tilden Mining Company unit EUKILN1 to allow conversion of the SO_2 concentration to units of the standard (ppmv). The number of monitors is dependent on the emission standard selected (5 ppmv or a minimum of 95 percent removal efficiency). Compliance with the emission standard selected for SO_2 shall be determined using data from the CEMS corrected to 7 percent oxygen.

(3) Except for CEMS breakdowns, out-of-control periods, repairs, maintenance periods, calibration checks, and zero and high-level drift adjustments, all CEMS required by this rule shall be in continuous operation and meet minimum frequency of operation requirements at (l)(3)(i–viii) during all periods of process operation of the indurating furnaces, including periods of process unit startup, shutdown, and malfunction.

(i) Continuous monitoring systems for measuring the pollutant, NO_X or SO_2, and diluent gas shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) Hourly averages shall be computed using at least one data point in each fifteen-minute quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant in an hour) if data are unavailable as a result of performance of calibration, quality assurance, preventive maintenance activities, or backups of data from data acquisition and handling system, and recertification events.

(iii) When valid pollutant emission data in pounds per hour or pounds per million BTU are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments, emission data must be obtained by using other monitoring systems approved by the EPA, and incorporated into the monitoring plan, to provide emission data for a minimum of 18 hours in each 24 hour period and at least 22 out of 30 successive unit operating days.

(iv) Data substitution must not be used for purposes of determining compliance under this regulation.

(v) All CEMS (and emission testing) data shall be reduced and reported in units of the applicable standard.

(vi) A Quality Control Program Plan must be developed and implemented for all CEMS required by this rule. The plan will include, at a minimum, the information described at 40 CFR 63.8(d), including calibration checks, calibration drift adjustments, preventative maintenance, data collection, recording and reporting, accuracy audits/procedures, periodic performance evaluations, and a corrective action program for CEMS problems and excess emission events.

(vii) The owner or operator must develop and implement a written startup, shutdown, and malfunction plan for NO_X and SO_2 according to the provisions in § 63.6(e)(3).

(viii) Performance evaluation of continuous monitoring systems. When required by a relevant standard the owner or operator of an affected source being monitored with continuous emission monitoring equipment shall conduct a performance evaluation of the CEMS. Such performance evaluation shall be conducted according to the applicable specifications and procedures described in 40 CFR 63.8(e) and incorporated into the Quality Control Program Plan.

(4) No later than the compliance date of this regulation, the owner or operator of EUKILN1 shall conduct initial performance testing for NO_X and SO_2, in accordance with the requirements of 40 CFR 63.7 and Appendix A of Part 60 to determine compliance with applicable emission limits/standards. Specific testing shall be described in the intent to test form submitted in accordance with the rule. The general reference methods to be used for initial testing will include: Methods 1–4, 6–6C, and 7–7E. Performance testing for demonstrating compliance with NO_X and SO_2 emission limits (if the 5 ppmv emission standard is selected) shall include testing emissions after exiting the control device. Performance testing for demonstrating compliance with the SO_2 removal efficiency standard shall include measurement of SO_2 concentrations at the inlet to the control device and in the duct/stack after emissions exit the control device.

(m) Recordkeeping Requirements

(1)(i) Records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(ii) As specified in § 63.10(b)(1), records must be kept for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(iii) Records must be kept on site for at least 2 years after the date of each occurrence, measurement, maintenance, report, or record according to § 63.10(b)(1). Records may be kept offsite for the remaining 3 years.

(2) Records listed in paragraphs (2)(i) through (iv) of this section must be kept for a period of five years.

(i) A copy of each notification and report submitted to comply with this subpart, including all documentation supporting any initial notification or notification of compliance status submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv).

(ii) The records in 40 CFR 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(iii) Records of performance tests and performance evaluations as required in 40 CFR 63.10(b)(2)(viii).

(iv) Records of all major maintenance conducted on emission units, pollution control equipment, and CEMS.

(3) For each CEMS, the records specified in paragraphs (3)(i) through (vii) of this section must be kept.

(i) Records described in 40 CFR 63.10(b)(2)(vi) through (xi).

(ii) Previous (that is, superceded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(iii) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(iv) All CEMS data including the date, place, and time of sampling or measurement, parameters sampled or measured, and results.

(v) Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR part 60, appendix B, Performance Specification 2, Procedure 1 or 40 CFR part 75.

(vi) All records required by 40 CFR part 60, appendix F, Procedure 1 or 40 CFR part 75.

(vii) Records of the NO_X emissions in the units of the standard. The owner or operator shall convert the monitored data into the appropriate unit of the emission limitation using an appropriate conversion factors and F-factors. F-factors used for purposes of this rule shall be documented in the monitoring plan and developed in accordance with 40 CFR part 60, appendix A, Method 19. The owner or operator may use an alternate method to calculate the NO_X emissions upon written approval from EPA.

(n) Reporting Requirements

(1) Unless otherwise stated all requests, reports, submittals, notifications, and other communications to the Regional Administrator required by this section shall be submitted, unless instructed otherwise, to the Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, Region 5 (E–19J), at 77 West Jackson Boulevard, Chicago, Illinois 60604.

(2)(i) If the owner or operator is required to conduct a performance test, a notification of intent to conduct a performance test must be submitted at least 60 calendar days before the performance test is scheduled to begin, as required in 40 CFR 63.7(b)(1).

(ii) If the owner or operator is required to conduct a performance test or other initial compliance demonstration, a notification of compliance status must be submitted according to 40 CFR 63.9(h)(2)(ii). The initial notification of compliance status must be submitted by the dates specified in paragraphs (2)(ii)(A) through (B) of this section.

(A) For each initial compliance demonstration that does not include a performance test, notification of compliance status must be submitted before the close of business on the 30th calendar day following completion of the initial compliance demonstration.

(B) For each initial compliance demonstration that does include a performance test, notification of compliance status, including the performance test results, must be submitted before the close of business on the 60th calendar day following the completion of the performance test according to § 63.10(d)(2).

(3) The recordkeeping requirements for CEMS performance testing are found in 40 CFR 60.7(c) and (d). All emission data shall be reported in the units of the standard.

(4) The recordkeeping requirements for non-continuous performance testing are found in 40 CFR 60.7(b). The owner or operator shall submit a written report of the results from all required non-CEMS performance tests to EPA within

90 calendar days of the completion of the performance test.

(5) Compliance Reports. Unless the Administrator has approved a different schedule, a semiannual compliance report must be submitted, according to the paragraphs (5)(i) through (iv) of this section.

(i) The first compliance report must cover the beginning period on the compliance date that is specified for the affected source and ended on June 30 or December 31, whichever date comes first after the compliance date that is specified for the affected source.

(ii) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever comes first after the first compliance report is due.

(iii) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(iv) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date comes first after the end of the semiannual reporting period.

(6) Compliance report contents. Each compliance report must include the information in paragraphs (6)(i) through (iii) of this section and, as applicable, in paragraphs (6)(iv) through (viii) of this section.

(i) Company name and address.

(ii) Statement by a responsible official, with the official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) If the source had a startup, shutdown, or malfunction during the reporting period and the owner or operator took actions consistent with the source's startup, shutdown, and malfunction plan, the compliance report must include the information in § 63.10(d)(5)(i).

(v) If there were no deviations from the continuous NO_X and SO_2 compliance requirements that apply to the affected source, then a statement that there were no deviations from the emission limitations during the reporting period must be provided.

(vi) If there were no periods during which a continuous monitoring system was out-of-control as specified in § 63.8(c)(7), then a statement that there were no periods during which a continuous monitoring system was out-of-control during the reporting period must be provided.

(vii) For each deviation from a NO_X and SO_2 emission limitation occurring at an affected source where a continuous monitoring system is being used to comply with the emission limitation in this subpart, the information in paragraphs (6)(i) through (iv) of this section and the information in paragraphs (6)(vii)(A) through (K) of this section must be included. This includes periods of startup, shutdown, and malfunction.

(A) The date and time that each malfunction started and stopped.

(B) The date and time that each continuous monitoring system was inoperative, except for zero (low-level) and high-level checks.

(C) The date, time, and duration that each continuous monitoring system was out-of-control, including the information in § 63.8(c)(8).

(D) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(E) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(F) A breakdown of the total duration of the deviations during the reporting period including those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(G) A summary of the total duration of continuous monitoring system downtime during the reporting period and the total duration of continuous monitoring system downtime as a percent of the total source operating time during the reporting period.

(H) A brief description of the process units.

(I) A brief description of the continuous monitoring system.

(J) The date of the latest continuous monitoring system certification or audit.

(K) A description of any changes in continuous monitoring systems, processes, or controls since the last reporting period.

(7) Immediate startup, shutdown, and malfunction report. If the affected source had a startup, shutdown, or malfunction during the semiannual reporting period that was not consistent with the startup, shutdown, and malfunction plan, an immediate startup, shutdown, and malfunction report must be submitted according to the requirements in § 63.10(d)(5)(ii).

(8) Notification of performance evaluation. (i) The owner or operator shall notify the Administrator in writing of the date of the performance evaluation simultaneously with the notification of the performance test date required under § 63.7(b) or at least 60 days prior to the date the performance evaluation is scheduled to begin if no performance test is required.

(ii)(A) Submission of site-specific performance evaluation test plan. Before conducting a required CEMS performance evaluation, the owner or operator of an affected source shall develop and submit a site-specific performance evaluation test plan to the Administrator for approval upon request. The performance evaluation test plan shall include the evaluation program objectives, an evaluation program summary, the performance evaluation schedule, data quality objectives, and both an internal and external QA program. Data quality objectives are the pre-evaluation expectations of precision, accuracy, and completeness of data.

(B) The internal QA program shall include, at a minimum, the activities planned by routine operators and analysts to provide an assessment of CEMS performance. The external QA program shall include, at a minimum, systems audits that include the opportunity for on-site evaluation by the Administrator of instrument calibration, data validation, sample logging, and documentation of quality control data and field maintenance activities.

(C) The owner or operator of an affected source shall submit the site-specific performance evaluation test plan to the Administrator (if requested) at least 60 days before the performance test or performance evaluation is scheduled to begin, or on a mutually agreed upon date, and review and approval of the performance evaluation test plan by the Administrator will occur with the review and approval of the site-specific test plan (if review of the site-specific test plan is requested).

(D) The Administrator may request additional relevant information after the submittal of a site-specific performance evaluation test plan.

(E) In the event that the Administrator fails to approve or disapprove the site-specific performance evaluation test plan within the time period specified in § 63.7(c)(3), the following conditions shall apply:

(*1*) If the owner or operator intends to demonstrate compliance using the monitoring method(s) specified in the relevant standard, the owner or operator shall conduct the performance evaluation within the time specified in this subpart using the specified method(s);

(*2*) If the owner or operator intends to demonstrate compliance by using an alternative to a monitoring method specified in the relevant standard, the owner or operator shall refrain from conducting the performance evaluation until the Administrator approves the use of the alternative method. If the Administrator does not approve the use of the alternative method within 30 days before the performance evaluation is scheduled to begin, the performance evaluation deadlines specified in paragraph (5)(iv) of this section may be extended such that the owner or operator shall conduct the performance evaluation within 60 calendar days after the Administrator approves the use of the alternative method. Notwithstanding the requirements in the preceding two sentences, the owner or operator may proceed to conduct the performance evaluation as required in this section (without the Administrator's prior approval of the site-specific performance evaluation test plan) if he/she subsequently chooses to use the specified monitoring method(s) instead of an alternative.

(F) Neither the submission of a site-specific performance evaluation test plan for approval, nor the Administrator's approval or disapproval of a plan, nor the Administrator's failure to approve or disapprove a plan in a timely manner shall—

(*1*) Relieve an owner or operator of legal responsibility for compliance with any applicable provisions of this part or with any other applicable Federal, State, or local requirement; or

(*2*) Prevent the Administrator from implementing or enforcing this part or taking any other action under the Act.

(iii) Conduct of performance evaluation and performance evaluation dates. The owner or operator of an affected source shall conduct a performance evaluation of a required CEMS during any performance test required under § 63.7 in accordance with the applicable performance specification as specified in the relevant standard. If a performance test is not required, or the requirement for a performance test has been waived under § 63.7(h), the owner or operator of an affected source shall conduct the performance evaluation not later than 180 days after the appropriate compliance date for the affected source, as specified in § 63.7(a), or as otherwise specified in the relevant standard.

(iv) Reporting performance evaluation results. The owner or operator shall furnish the Administrator a copy of a written report of the results of the performance evaluation simultaneously with the results of the performance test required under § 63.7 or within 60 days of completion of the performance evaluation if no test is required, unless otherwise specified in a relevant standard. The Administrator may request that the owner or operator submit the raw data from a performance evaluation in the report of the performance evaluation results.

3. Section 52.1235 is amended by adding paragraphs (a), (b), (c), (d) and (e) to read as follows:

§ 52.1235 Regional Haze.

(a) The requirements of section 169A of the Clean Air Act are not met because the regional haze plan submitted by the state on December 30, 2009, and on May 8, 2012, does not meet the requirements of 40 CFR 51.308(e) with respect to NO_X and SO_2 emissions from United States Steel Corporation, Keetac of Keewatin, Minnesota; Hibbing Taconite Company of Hibbing, Minnesota; United States Steel Corporation, Minntac of Mountain Iron, Minnesota; United Taconite, LLC of Forbes, Minnesota; ArcelorMittal Minorca Mine, Inc. near Virginia, Minnesota; and Northshore Mining Company—Silver Bay of Silver Bay, Minnesota. The requirements for these facilities are satisfied by complying with the requirements of § 52.1235.

(b)(1) NO_X Emission Limits.

(i) United States Steel Corporation, Keetac: An emission limit of 1.2 lb NO_X/MMBtu at 7 percent oxygen, based on a 30-day rolling average, shall apply to the Grate Kiln pelletizing furnace (EU030), beginning 1 year and 6 months from the effective date of this rule.

(ii) Hibbing Taconite Company: An emission limit of 1.2 lb NO_X/MMBtu at 7 percent oxygen, based on a 30-day rolling average, shall apply to the Line 1 pelletizing furnace (EU020) beginning 1 year and 6 months from the effective date of this rule. An emission limit of 1.2 lb NO_X/MMBtu at 7 percent oxygen, based on a 30-day rolling average, shall apply to the Line 2 pelletizing furnace (EU021) beginning 3 years and 6 months from the effective date of this rule. An emission limit of 1.2 lb NO_X/MMBtu at 7 percent oxygen, based on a 30-day rolling average, shall apply to the Line 3 pelletizing furnace (EU022) beginning 2 years and 6 months from the effective date of this rule.

(iii) United States Steel Corporation, Minntac: An emission limit of 1.2 lb NO_X/MMBtu at 7 percent oxygen, based on a 30-day rolling average, shall apply to each of the five indurating furnaces (EU225, EU261, EU282, EU315, and EU334). The owner or operator shall comply with this NO_X emission limits beginning 4 years and 11 months from the effective date of this rule for the Line 3 indurating furnace (EU225), beginning 3 years from the effective date of this rule for the Line 4 indurating furnace (EU261), beginning 4 years from the effective date of this rule for the Line 5 indurating furnace (EU282), beginning 1 year from the effective date of this rule for the Line 6 indurating furnace (EU315), and beginning 2 years from the effective date of this rule for the Line 7 indurating furnace (EU334).

(iv) United Taconite: An emission limit of 1.2 lb NO_X/MMBtu at 7 percent oxygen, based on a 30-day rolling average, shall apply to the Line 1 pellet furnace (EU040) beginning 2 years and 6 months from the effective date of this rule. An emission limit of 1.2 lb NO_X/MMBtu at 7 percent oxygen, based on a 30-day rolling average, shall apply to the Line 2 pellet furnace (EU046) beginning 1 year and 6 months from the effective date of this rule.

(v) ArcelorMittal Minorca Mine: An emission limit of 1.2 lb NO_X/MMBtu at 7 percent oxygen, based on a 30-day rolling average, shall apply to the indurating furnace (EU026) beginning 1 year and 6 months from the effective date of this rule.

(vi) Northshore Mining Company—Silver Bay: An emission limit of 1.2 lb NO_X/MMBtu at 7 percent oxygen, based on a 30-day rolling average, shall apply to Furnace 11 (EU100/EU104) beginning 1 year and 6 months from the effective date of this rule. An emission limit of 1.2 lb NO_X/MMBtu at 7 percent oxygen, based on a 30-day rolling average, shall apply to Furnace 12 (EU110/114) beginning 2 years and 6 months from the effective date of this rule. An emission limit of 0.085 lb/hr at 7 percent oxygen, based on a 30-day rolling average, shall apply to Process Boiler #1 (EU003) and Process Boiler #2 (EU004) beginning 5 years from the effective date of this rule. The 0.085 lb/hr emission limit for each process boiler applies at all times a unit is operating, including periods of start-up, shut-down and malfunction.

(2) SO_2 Emission Limits.

(i) United States Steel Corporation, Keetac: An emission limit of 225 lb SO_2/hr at 7 percent oxygen, based on a 30-day rolling average, shall apply to the Grate Kiln pelletizing furnace (EU030). The owner or operator shall also operate its wet scrubber for EU030 to achieve a minimum SO_2 control efficiency of 57.0 percent and to achieve a hydrogen ion concentration (pH) in the scrubber liquid at or above 7.5. Compliance with all SO_2 emission limits, control efficiency and pH standards for EU030 is required beginning 90 days from the effective date of this rule.

(ii) Hibbing Taconite Company: Emission limits of 56.0 lb SO_2/hr at 7 percent oxygen shall apply to Line 1 (EU020), 63.0 lb SO_2/hr at 7 percent oxygen shall apply to Line 2 (EU021), and 64.0 lb SO_2/hr at 7 percent oxygen shall apply to Line 3 (EU022). The SO_2 emission limits for these three pelletizing furnaces are based on a 30-day rolling average and do not apply when a unit is combusting fuel oil. Compliance with the emission limits is required beginning 3 months from the effective date of this rule.

(iii) United States Steel Corporation, Minntac: The emission limits for the five indurating furnaces are 71.3 lb SO_2/hr at 7 percent oxygen for Line 3 (EU225), 56.1 lb SO_2/hr at 7 percent oxygen for Line 4 (EU261), 67.9 lb SO_2/hr at 7 percent oxygen for Line 5 (EU282), 64.5 lb SO_2/hr at 7 percent oxygen for Line 6 (EU315), and 67.1 lb SO_2/hr at 7 percent oxygen for Line 7 (EU334). The SO_2 emission limits are based on a 30-day rolling average and apply to each of the five indurating furnaces, beginning 3 months from the effective date of this rule.

(iv) United Taconite: An emission limit of 5 ppmv SO_2 at 7 percent oxygen shall apply to the Line 1 pellet furnace (EU040) beginning 4 years from the effective date of this rule. As an alternate, the owner or operator may select to comply with a 95.0 percent or greater SO_2 removal efficiency, based on a 30-day rolling average, on the control device for the Line 1 pellet furnace (EU040) beginning 4 years from the effective date of this rule. An emission limit of 5 ppmv SO_2 at 7 percent oxygen shall apply to the Line 2 pellet furnace (EU042) beginning 2 years from the effective date of this rule. As an alternate, the owner or operator may select to comply with a 95.0 percent or greater SO_2 removal efficiency, based on a 30-day rolling average, on the control device for the Line 2 pellet furnace (EU042) beginning 2 years from the effective date of this rule.

(v) ArcelorMittal Minorca Mine: An emission limit of 23.0 lb SO_2/hr at 7 percent oxygen, based on a 30-day rolling average, shall apply to the indurating furnace (EU026) beginning 3 months from the effective date of this rule. This limit shall not apply when the unit is combusting fuel oil.

(vi) Northshore Mining Company—Silver Bay: An emission limit of 16.3 lb SO_2/hr at 7 percent oxygen, based on a 30-day rolling average, shall apply to Furnace 11 (EU100/EU104). An emission limit of 17.1 lb SO_2/hr at 7 percent oxygen, based on a 30-day rolling average, shall apply to Furnace 12 (EU110/EU114). The owner or operator shall also operate its control device for EU100/EU104 and EU110/EU114 to achieve a minimum SO_2 control efficiency of 80.0 percent. The owner or operator shall comply with the SO_2 emission limits/standards beginning 6 months from the effective date of this rule. These limits shall not apply when the subject unit is combusting fuel oil.

(c) Testing and Monitoring.

(1) No later than the compliance date of this regulation, the owner or operator of the respective facility shall install, certify, calibrate, maintain and operate Continuous Emissions Monitoring Systems (CEMS) for NO_X on United States Steel Corporation, Keetac unit EU030; Hibbing Taconite Company units EU020, EU021, and EU022; United States Steel Corporation, Minntac units EU225, EU261, EU282, EU315, and EU334; United Taconite units EU040 and EU042; ArcelorMittal Minorca Mine unit EU026; and Northshore Mining Company—Silver Bay units Furnace 11 (EU100/EU104) and Furnace 12 (EU110/EU114). All NO_X CEMS must be installed, certified, calibrated, maintained and operated in accordance with 40 CFR 63.8, and Appendices B and F of Part 60. The owner or operator shall install, certify, calibrate, maintain and operate a continuous diluent monitor (O_2 or CO_2) and continuous flow rate monitor on each unit identified by this rule to allow conversion of the NO_X concentration to units of the standard (lbs/MMBtu). Compliance with the emission limits for NO_X shall be determined using data from the CEMS corrected to 7 percent oxygen.

(2) No later than the compliance date of this regulation, the owner or operator shall install, certify, calibrate, maintain and operate one or more CEMS for SO_2 on United States Steel Corporation, Keetac unit EU030; Hibbing Taconite Company units EU020, EU021, and EU022; United States Steel Corporation, Minntac units EU225, EU261, EU282, EU315, and EU334; United Taconite units EU040 and EU042; ArcelorMittal Minorca Mine unit EU026; and Northshore Mining Company—Silver Bay units Furnace 11 (EU100/EU104) and Furnace 12 (EU110/EU114). All SO_2 CEMS must be installed, certified, calibrated, maintained and operated in accordance with 40 CFR 63.8, and Appendices B and F of Part 60. The owner or operator shall install, certify, calibrate, maintain and operate a continuous diluent monitor (O_2 or CO_2) and continuous flow rate monitor on each unit identified by this rule to allow conversion of the SO_2 concentration to units of the standard (lb/hr, ppmv or a minimum of 95 percent removal efficiency). The number of monitors is dependent on the emission standard selected for purposes of demonstrating compliance. Compliance with the emission standard selected for SO_2 shall be determined using data from the CEMS corrected to 7 percent oxygen.

(3) Except for CEMS breakdowns, out-of-control periods, repairs, maintenance periods, calibration checks, and zero and high-level drift adjustments, all CEMS required by this rule shall be in continuous operation and meet minimum frequency of operation requirements at (c)(3)(i–viii) during all periods of process unit operation, including periods of process unit startup, shutdown, and malfunction.

(i) Continuous monitoring systems for measuring the pollutant, NO_X or SO_2, and diluent gas shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) Hourly averages shall be computed using at least one data point in each fifteen-minute quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant in an hour) if data are unavailable as a result of performance of calibration, quality assurance, preventive maintenance activities, or backups of data from data acquisition and handling system, and recertification events.

(iii) When valid pollutant emission data in pounds per hour or pounds per million BTU are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments, emission data must be obtained by using other monitoring systems approved by the EPA, and incorporated into the monitoring plan, to provide emission data for a minimum of 18 hours in each 24 hour period and at least 22 out of 30 successive unit operating days.

(iv) Data substitution must not be used for purposes of determining compliance under this regulation.

(v) All CEMS (and emission testing) data shall be reduced and reported in units of the applicable standard.

(vi) A Quality Control Program Plan must be developed and implemented for all CEMS required by this rule. The plan will include, at a minimum, the information described at 40 CFR 63.8(d), including calibration checks, calibration drift adjustments, preventative maintenance, data collection, recording and reporting, accuracy audits/

procedures, periodic performance evaluations, and a corrective action program for CEMS problems and excess emission events.

(vii) The owner or operator must develop and implement a written startup, shutdown, and malfunction plan for NO_X and SO_2 according to the provisions in § 63.6(e)(3).

(viii) Performance evaluation of continuous monitoring systems. When required by a relevant standard the owner or operator of an affected source being monitored with continuous emission monitoring equipment shall conduct a performance evaluation of the CEMS. Such performance evaluation shall be conducted according to the applicable specifications and procedures described in 40 CFR 63.8(e) and incorporated into Quality Control Program Plan.

(4) No later than the compliance date of this regulation, the owner or operator of each unit identified in this rule shall conduct initial performance testing for NO_X and SO_2, in accordance with the requirements of 40 CFR 63.7 and Appendix A of Part 60 to determine compliance with applicable emission limits/standards. Specific testing shall be described in the intent to test form submitted in accordance with the rule. The general reference methods to be used for initial testing will include: Methods 1–4, 6–6C, and 7–7E. Performance testing for demonstrating compliance with NO_X and SO_2 emission limits (lb/MMBtu, lb/hr, or ppmv) shall include testing emissions after exiting the control device. Performance testing for demonstrating compliance with the SO_2 removal efficiency standard shall include measuring SO_2 concentrations at the inlet to the control device and in the duct/stack after emissions exit the control device.

(5) No later than the compliance date of this regulation, owners or operators utilizing a wet scrubber to control SO_2 shall include in the performance testing an evaluation of compliance with the pH limits established by this rule. The pH evaluation shall be performed in accordance with the requirements of 40 CFR 163.3 using EPA Method 150.2.

(d) Recordkeeping Requirements.

(1)(i) Records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(ii) As specified in § 63.10(b)(1), records must be kept for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(iii) Records must be kept on site for at least 2 years after the date of each occurrence, measurement, maintenance, report, or record according to § 63.10(b)(1). Records may be kept offsite for the remaining 3 years.

(2) Records listed in paragraphs (2)(i) through (iv) of this section must be kept for a period of five years.

(i) A copy of each notification and report submitted to comply with this subpart, including all documentation supporting any initial notification or notification of compliance status submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv).

(ii) The records in 40 CFR 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(iii) Records of performance tests and performance evaluations as required in 40 CFR 63.10(b)(2)(viii).

(iv) Records of all major maintenance conducted on emission units, pollution control equipment, and CEMS.

(3) For each CEMS, the records specified in paragraphs (3)(i) through (vii) of this section must be kept.

(i) Records described in 40 CFR 63.10(b)(2)(vi) through (xi).

(ii) Previous (that is, superceded) versions of the performance evaluation plan as required in 63.8(d)(3).

(iii) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(iv) All CEMS data including the date, place, and time of sampling or measurement, parameters sampled or measured, and results.

(v) Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR part 60, appendix B, Performance Specification 2, Procedure 1 or 40 CFR part 75.

(vi) All records required by 40 CFR part 60, appendix F, Procedure 1 or 40 CFR part 75.

(vii) Records of the NO_X emissions in the units of the standard. The owner or operator shall convert the monitored data into the appropriate unit of the emission limitation using an appropriate conversion factor and F-factors. F-factors used for purposes of this rule shall be documented in the monitoring plan and developed in accordance with 40 CFR part 60, appendix A, Method 19. The owner or operator may use an alternate method to calculate the NO_X emissions upon written approval from EPA.

(e) Reporting Requirements.

(1) Unless otherwise stated all requests, reports, submittals, notifications, and other communications to the Regional Administrator required by this section shall be submitted, unless instructed otherwise, to the Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, Region 5 (E–19J), at 77 West Jackson Boulevard, Chicago, Illinois 60604.

(2)(i) If the owner or operator is required to conduct a performance test, a notification of intent to conduct a performance test must be submitted at least 60 calendar days before the performance test is scheduled to begin, as required in 40 CFR 63.7(b)(1).

(ii) If the owner or operator is required to conduct a performance test or other initial compliance demonstration, a notification of compliance status must be submitted according to 40 CFR 63.9(h)(2)(ii). The initial notification of compliance status must be submitted by the dates specified in paragraphs (2)(ii)(A) through (B) of this section.

(A) For each initial compliance demonstration that does not include a performance test, notification of compliance status must be submitted before the close of business on the 30th calendar day following completion of the initial compliance demonstration.

(B) For each initial compliance demonstration that does include a performance test, notification of compliance status, including the performance test results, must be submitted before the close of business on the 60th calendar day following the completion of the performance test according to § 63.10(d)(2).

(3) The recordkeeping requirements for CEMS performance testing are found in 40 CFR 60.7(c) and (d). All emission data shall be reported in the units of the standard.

(4) The recordkeeping requirements for non-continuous performance testing are found in 40 CFR 60.7(b). The owner or operator shall submit a written report of the results from all required non-CEMS performance tests to EPA within 90 calendar days of the completion of the performance test.

(5) Compliance Reports. Unless the Administrator has approved a different schedule, a semiannual compliance report must be submitted, according to the paragraphs (5)(i) through (iv) of this section.

(i) The first compliance report must cover the beginning period on the compliance date that is specified for the affected source and ended on June 30 or December 31, whichever date comes first after the compliance date that is specified for the affected source.

(ii) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever comes first after the first compliance report is due.

(iii) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(iv) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date comes first after the end of the semiannual reporting period.

(6) Compliance report contents. Each compliance report must include the information in paragraphs (6)(i) through (iii) of this section and, as applicable, in paragraphs (6)(iv) through (viii) of this section.

(i) Company name and address.

(ii) Statement by a responsible official, with the official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) If the source had a startup, shutdown, or malfunction during the reporting period and the owner or operator took actions consistent with the source's startup, shutdown, and malfunction plan, the compliance report must include the information in § 63.10(d)(5)(i).

(v) If there were no deviations from the continuous NO_X and SO_2 compliance requirements that apply to the affected source, then a statement that there were no deviations from the emission limitations during the reporting period must be provided.

(vi) If there were no periods during which a continuous monitoring system was out-of-control as specified in § 63.8(c)(7), then a statement that there were no periods during which a continuous monitoring system was out-of-control during the reporting period must be provided.

(vii) For each deviation from a NO_X and SO_2 emission limitation occurring at an affected source where a continuous monitoring system is being used to comply with the emission limitation in this subpart, the information in paragraphs (6)(i) through (iv) of this section and the information in paragraphs (6)(vii)(A) through (K) of this section must be included. This includes periods of startup, shutdown, and malfunction.

(A) The date and time that each malfunction started and stopped.

(B) The date and time that each continuous monitoring system was inoperative, except for zero (low-level) and high-level checks.

(C) The date, time, and duration that each continuous monitoring system was out-of-control, including the information in § 63.8(c)(8).

(D) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(E) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(F) A breakdown of the total duration of the deviations during the reporting period including those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(G) A summary of the total duration of continuous monitoring system downtime during the reporting period and the total duration of continuous monitoring system downtime as a percent of the total source operating time during the reporting period.

(H) A brief description of the process units.

(I) A brief description of the continuous monitoring system.

(J) The date of the latest continuous monitoring system certification or audit.

(K) A description of any changes in continuous monitoring systems, processes, or controls since the last reporting period.

(7) Immediate startup, shutdown, and malfunction report. If the affected source had a startup, shutdown, or malfunction during the semiannual reporting period that was not consistent with the startup, shutdown, and malfunction plan, an immediate startup, shutdown, and malfunction report must be submitted according to the requirements in § 63.10(d)(5)(ii).

(8) Notification of performance evaluation. (i) The owner or operator shall notify the Administrator in writing of the date of the performance evaluation simultaneously with the notification of the performance test date required under § 63.7(b) or at least 60 days prior to the date the performance evaluation is scheduled to begin if no performance test is required.

(ii)(A) Submission of site-specific performance evaluation test plan. Before conducting a required CEMS performance evaluation, the owner or operator of an affected source shall develop and submit a site-specific performance evaluation test plan to the Administrator for approval upon request. The performance evaluation test plan shall include the evaluation program objectives, an evaluation program summary, the performance evaluation schedule, data quality objectives, and both an internal and external QA program. Data quality objectives are the pre-evaluation expectations of precision, accuracy, and completeness of data.

(B) The internal QA program shall include, at a minimum, the activities planned by routine operators and analysts to provide an assessment of CEMS performance. The external QA program shall include, at a minimum, systems audits that include the opportunity for on-site evaluation by the Administrator of instrument calibration, data validation, sample logging, and documentation of quality control data and field maintenance activities.

(C) The owner or operator of an affected source shall submit the site-specific performance evaluation test plan to the Administrator (if requested) at least 60 days before the performance test or performance evaluation is scheduled to begin, or on a mutually agreed upon date, and review and approval of the performance evaluation test plan by the Administrator will occur with the review and approval of the site-specific test plan (if review of the site-specific test plan is requested).

(D) The Administrator may request additional relevant information after the submittal of a site-specific performance evaluation test plan.

(E) In the event that the Administrator fails to approve or disapprove the site-specific performance evaluation test plan within the time period specified in § 63.7(c)(3), the following conditions shall apply:

(*1*) If the owner or operator intends to demonstrate compliance using the monitoring method(s) specified in the relevant standard, the owner or operator shall conduct the performance evaluation within the time specified in this subpart using the specified method(s);

(*2*) If the owner or operator intends to demonstrate compliance by using an alternative to a monitoring method specified in the relevant standard, the owner or operator shall refrain from conducting the performance evaluation until the Administrator approves the use of the alternative method. If the Administrator does not approve the use of the alternative method within 30 days before the performance evaluation is scheduled to begin, the performance evaluation deadlines specified in paragraph (5)(iv) of this section may be extended such that the owner or operator shall conduct the performance evaluation within 60 calendar days after the Administrator approves the use of the alternative method. Notwithstanding the requirements in the preceding two sentences, the owner or operator may proceed to conduct the performance evaluation as required in this section (without the Administrator's prior approval of the site-specific performance evaluation test plan) if he/she subsequently chooses to use the specified monitoring method(s) instead of an alternative.

(F) Neither the submission of a site-specific performance evaluation test plan for approval, nor the Administrator's approval or disapproval of a plan, nor the Administrator's failure to approve or disapprove a plan in a timely manner shall—

(*1*) Relieve an owner or operator of legal responsibility for compliance with any applicable provisions of this part or with any other applicable Federal, State, or local requirement; or

(*2*) Prevent the Administrator from implementing or enforcing this part or taking any other action under the Act.

(iii) Conduct of performance evaluation and performance evaluation dates. The owner or operator of an affected source shall conduct a performance evaluation of a required CEMS during any performance test required under § 63.7 in accordance with the applicable performance specification as specified in the relevant standard. If a performance test is not required, or the requirement for a performance test has been waived under § 63.7(h), the owner or operator of an affected source shall conduct the performance evaluation not later than 180 days after the appropriate compliance date for the affected source, as specified in § 63.7(a), or as otherwise specified in the relevant standard.

(iv) Reporting performance evaluation results. The owner or operator shall furnish the Administrator a copy of a written report of the results of the performance evaluation simultaneously with the results of the performance test required under § 63.7 or within 60 days of completion of the performance evaluation if no test is required, unless otherwise specified in a relevant standard. The Administrator may request that the owner or operator submit the raw data from a performance evaluation in the report of the performance evaluation results.

[FR Doc. 2012–19789 Filed 8–14–12; 8:45 am]

BILLING CODE 6560–50–P