

**Prevention of Significant Deterioration  
Air Pollution Control Construction Permit Application**

**Appendix B.**

**Control Technology Review for the  
Natural Gas-Fired Boilers.**

**50 MW Biomass-Fired Cogeneration Facility to be  
Located at the Domtar – Rothschild Mill.**

**March, 2010**

**Prepared for:**

**we energies**   
We Energies  
231 W. Michigan St.  
Milwaukee, WI 53203

**Prepared By:**



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**RTP ENVIRONMENTAL ASSOCIATES INC.®**  
**903 Superior Avenue, Suite 6**  
**Tomah, WI 54660**



# Executive Summary

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This document is a Control Technology Review for two new natural gas-fired package boilers, designated as Boilers B02 and B03, at the We Energies' 50 MW Biomass Fuels Plant in Rothschild. This control technology review is required for major new sources under the Prevention of Significant Deterioration (PSD) program under NR 405.08, Wis. Adm. Code.

The proposed boilers will be package boilers designed to provide up to 125,000 pounds per hour of steam. To deliver this steaming capacity, each boiler will have a maximum design heat input capacity of 175 million Btu per hour. The only boiler fuel will be natural gas. Each boiler will be equipped with ultra-low NO<sub>x</sub> burners and flue gas recirculation to control emissions of CO, NO<sub>x</sub>, PM/PM<sub>10</sub>, PM<sub>2.5</sub>, and VOCs.

Table ES-1 summarizes the proposed emission limits which represent the best available control technology (BACT) for these new package boilers, and the potential emissions for each boiler. The proposed BACT conditions are summarized in Table ES-2.

**TABLE ES-1. Proposed emission limits representing BACT for each package boiler B02 and B03.**

POLLUTANT		PROPOSED LIMIT, lb/mmBtu	POTENTIAL TO EMIT, ton/year
Carbon Monoxide	CO	0.06	32.6
Nitrogen Oxides	NO <sub>x</sub>	0.02	10.9
Particulate Matter	PM/PM <sub>10</sub>	0.0076	4.1
PM < 2.5 microns	PM <sub>2.5</sub>	0.0076	4.1
Sulfur Dioxide	SO <sub>2</sub>	0.0006	0.3
Organic Compounds	VOC	0.006	3.3
Fluorides (as HF)	HF	n/a	0.3

**TABLE ES-2. Proposed control technologies and emission limits representing BACT for the natural gas-fired Boilers B02 and B03.**

<b>Pollutant</b>	<b>Proposed Control Technology and Emission Limits</b>
Carbon Monoxide (CO)	(1) CO emissions shall be controlled using good combustion practices as BACT. (2) CO emissions may not exceed 0.06 lb/mmBtu, based on a 30-day rolling average.
Nitrogen Oxides (NO <sub>x</sub> )	(1) NO <sub>x</sub> emissions shall be controlled using Ultra Low NO <sub>x</sub> Burners and Flue Gas Recirculation in combination with good combustion practices as BACT. (2) NO <sub>x</sub> emissions may not exceed 0.02 lb/mmBtu, based on a 30-day rolling average.
Particulate Matter (PM) and PM <sub>10</sub>	(1) PM and PM <sub>10</sub> emissions shall be controlled using natural gas as fuel and good combustion practices as BACT. (2) PM and PM <sub>10</sub> emissions may not exceed 0.0076 lb/mmBtu.
PM <sub>2.5</sub>	(1) PM <sub>2.5</sub> emissions shall be controlled using natural gas as fuel and good combustion practices as BACT.. (2) PM <sub>2.5</sub> emissions may not exceed 0.0076 lb/mmBtu.
Sulfur Dioxide (SO <sub>2</sub> )	(1) SO <sub>2</sub> emissions shall be controlled using natural gas as fuel as BACT. (2) SO <sub>2</sub> emissions may not exceed 0.0006 lb/mmBtu.
Organic Compounds (VOC)	(1) VOC emissions shall be controlled using good combustion practices as BACT. (2) VOC emissions may not exceed 0.006 pounds per million Btu of heat input.
Fluorides (as HF)	(1) Fluoride (as HF) emissions shall be controlled using natural gas as fuel as BACT.

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# Chapter 1. Introduction and Source Description.

This document is a Control Technology Review for two new natural gas-fired package boilers, designated as Boilers B02 and B03, at the We Energies' 50 MW Biomass Fuels Plant in Rothschild. This control technology review is required for major new sources under the Prevention of Significant Deterioration (PSD) program under NR 405.08, Wis. Adm. Code.

The proposed boilers will be package boilers designed to provide up to 125,000 pounds per hour of steam. To deliver this steam capacity, each boiler will have a maximum design heat input capacity of 175 million Btu per hour. The only boiler fuel will be natural gas. Each boiler will be equipped with ultra-low NO<sub>x</sub> burners and flue gas recirculation to control emissions of CO, NO<sub>x</sub>, PM, PM<sub>10</sub>, PM<sub>2.5</sub>, and VOCs. A typical large industrial package boiler is shown in Figure 1-1. Potential emissions for each boiler, based on this control technology review, are summarized in Table 1-1.

**FIGURE 1-1. Large FM type water tube package boiler (The Babcock & Wilcox Company).**



**TABLE 1-1. Potential air emissions for each 125,000 lb/hr auxiliary package Boiler B02 and B03.**

POLLUTANT		UNCONTROLLED EMISSION FACTOR		MAXIMUM HEAT INPUT mmBtu/hr	POTENTIAL TO EMIT	
		lb/mmft <sup>3</sup>	lb/mmBtu		lb/hr	tons/yr
Carbon Monoxide	CO	63.0	0.06	175	10.50	32.6
Nitrogen Oxides	NO <sub>x</sub>	21.0	0.02	175	3.50	10.9
Particulate Matter	PM/PM <sub>10</sub>	7.6	0.0076	175	1.33	4.1
Particulate Matter	PM <sub>2.5</sub>	7.6	0.0076	175	1.33	4.1
Sulfur Dioxide	SO <sub>2</sub>	0.60	0.0006	175	0.11	0.3
Organic Compounds	OC	5.5	0.006	175	1.05	3.3
Lead	Pb	0.00050	0.0000005	175	0.000083	0.00026
Mercury	Hg	0.00026	0.0000002	175	0.000043	0.00013
Fluorides (as HF)	HF	0.0	0.00062	175	0.11	0.34
Sulfuric Acid Mist	H <sub>2</sub> SO <sub>4</sub>	0.006	0.000006	175	0.0011	0.0033

**Footnotes**

1. For natural gas combustion, the CO and NO<sub>x</sub> emission rates are based on concentrations of 75 and 9 ppm at a flue gas excess oxygen content of 5%. Potential emissions are based on CO and NO<sub>x</sub> emission rates of 0.06 and 0.02 lb/mmBtu, respectively.

$$E = \frac{KC_h F(20.9)}{20.9 - \%O_2} \quad \text{where, } E = \text{Emission Rate, lb/mmBtu}$$

$$F = \text{F-Factor, dscf/mmBtu}$$

<i>Natural Gas Combustion</i>		<i>K</i>	<i>C<sub>h</sub></i> , ppm	<i>F</i> , dscf/mmBtu	<i>%O<sub>2</sub></i>	<i>E</i> , lb/mmBtu
Carbon Monoxide	CO	7.59E-08	75	8,710	5.0	0.058
Nitrogen Oxides	NO <sub>x</sub>	1.19E-07	9	8,710	5.0	0.012

2. The emission factors for uncontrolled PM, PM<sub>10</sub>, PM<sub>2.5</sub>, SO<sub>2</sub>, VOC, lead, and mercury emissions are from the U.S. EPA's AP-42, *Compilation of Air Pollutant Emission Factors*, 5th Edition, section 1.4, Natural Gas Combustion. All PM<sub>10</sub> emissions are assumed to be PM<sub>2.5</sub>.

3. Sulfuric acid mist emissions for natural gas combustion are based on 1% conversion of SO<sub>2</sub> to SO<sub>3</sub>.

6. Potential emissions are based on limiting the fuel use to:

**Natural Gas:**  $HI = \underline{1,085,000}$  mmBtu, 12-month average  $\underline{6,200}$  hour/yr

# Chapter 2. Control Technology Review Methodology.

## 2.1 Best Available Control Technology Definition.

The Clean Air Act and the Prevention of Significant Deterioration (PSD) rules in the Code of Federal Regulations, 40 CFR 52.21(b)(12) define “best available control technology” (BACT) as:

“...an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under this Act which would be emitted from any proposed major stationary source or major modification which the administrator on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment of innovative fuel combustion techniques for control of each such pollutant. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61.”

In Wisconsin, BACT is defined as:

...means an emissions limitation, including a visible emissions standard, based on the maximum degree of reduction for each air contaminant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the department, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including clean fuels, fuel cleaning or treatment or innovative fuel combination techniques for control of the air contaminant. In no event may application of best available control technology result in emissions of any air contaminant which would exceed the emissions allowed by any applicable standard under chs. NR 440 and 445 to 449 and under sections 111 and 112 of the Act (42 USC 7411 and 7412). Emissions from any source utilizing clean fuels or any other means to comply with this subsection may not be allowed to increase above the levels that would have been required under this subsection as it existed prior to enactment of the 1990 clean air Act amendments on November 15, 1990. If the department determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. The standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results. (NR 405.02(7), Wis. Adm. Code)

The BACT requirement applies for a given pollutant to each individual new or modified emission unit when the project, on a facility-wide basis, has a significant net emissions increase for that pollutant. Individual BACT determinations are performed on a unit-by-unit, pollutant-by-pollutant basis. This BACT analysis considers potential controls for SO<sub>2</sub>, NO<sub>x</sub>, PM/PM<sub>10</sub>, CO, VOC, and sulfuric acid mist.

## 2.2 Top Down BACT Methodology.

The U.S. EPA recommends a “top-down” approach in conducting a BACT analysis. This method evaluates progressively less stringent control technologies until a level of control considered BACT is reached, based on the environmental, energy, and economic impacts. The top-down method was used in this analysis. The five steps of a top-down BACT analysis are:

1. Identify all available control technologies with practical potential for application to the emission unit and regulated pollutant under evaluation;
2. Eliminate all technically infeasible control technologies;
3. Rank remaining control technologies by effectiveness and tabulate a control hierarchy;
4. Evaluate most effective controls and document results; and
5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

The impact analysis of any BACT review includes an evaluation of environmental, energy, technical, and economic impacts. The net environmental impact associated with a control alternative may be considered if dispersion modeling analyses are performed. The energy impact analysis estimates the direct energy impacts of the control alternatives in units of energy consumption. If possible, the energy requirements for each control option are assessed in terms of total annual energy consumption. The most important issue of the BACT review is generally the economic impact. The economic impact of a control option is assessed in terms of cost effectiveness and ultimately, whether the option is economically reasonable. The economic impacts are reviewed on a cost per ton controlled basis, as directed by the U.S. EPA’s Office of Air Quality Planning and Standards (OAQPS) Cost Control Manual, Fifth Edition.

The EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which EPA believes must be met by any BACT determination, irrespective of whether it is conducted in a “top-down” manner. First, the BACT analysis must include consideration of the most stringent available technologies: i.e., those that provide the “maximum degree of emissions reduction.” Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of “energy, environmental, and economic impacts” contained in the record.

## 2.3 New Versus Modified Facilities.

There can be significant differences in the technical and economic feasibility of retrofitting controls on existing boilers, versus the use of these same controls on new boilers. In addition, a given control may not be able to achieve the same level of control when retrofitted onto existing units as the same control can achieve on new units. For example, the use of low NO<sub>x</sub> burners on existing boilers often cannot achieve the same NO<sub>x</sub>, CO, and VOC emission rates as the use of low NO<sub>x</sub> burners on a new boiler which has been designed to optimize the low NO<sub>x</sub> burner design. This can in turn affect the ultimate NO<sub>x</sub> emission rates which can be achieved by post combustion controls such as selective catalytic reduction.

Retrofitting controls on existing boilers can also have significantly different costs as compared to the use of these same technologies on new units. Retrofitting controls on existing boilers can have numerous issues, including site constraints and room for the new controls, demolition requirements for existing controls, and down time during construction and interconnection of the new systems.

## **2.4 Identifying Potential Control Technologies.**

As stated in the U.S. EPA's October 1990 New Source Review Workshop Manual, the first step in a "top-down" analysis is to identify, for the emissions unit in question, all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant being evaluated. Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant, including technologies employed outside of the United States. In some circumstances, inherently lower-polluting processes are appropriate for consideration as available control alternatives. The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies. Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative. In Step 1, applicants should identify all control options with potential application to the emissions unit under review.

## **2.5 Technical Feasibility.**

Step 2 of the BACT analysis involves the evaluation of all of the identified available control technologies from Step 1 to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar emission source, or there is technical agreement that the technology can be applied to the emission source. Technical infeasibility is demonstrated through clear physical, chemical, or other engineering principles that demonstrate that technical difficulties preclude the successful use of the control option.

The technology must be commercially available for it to be considered as a candidate for BACT. EPA's New Source Review Workshop Manual, page B.12 states, "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."

In general, if a control technology has been "demonstrated" successfully for the type of emission source under review, then it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine technical feasibility. Page B.17 of the New Source Review Workshop Manual states:

Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be

obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible. Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:

- concept stage;
- research and patenting;
- bench scale or laboratory testing;
- pilot scale testing;
- licensing and commercial demonstration; and
- commercial sales.

Applicability involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission source), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission source may not be applicable to a similar source depending on differences in physical and chemical gas stream characteristics.

## **2.6 Economic Feasibility.**

Economic feasibility is normally evaluated according to the average and incremental cost effectiveness. From the U.S. EPA's New Source Review Manual, page B.31, average cost effectiveness is the dollars per ton of pollutant reduced. The incremental cost effectiveness is the cost per ton reduced from the technology being evaluated as compared to the next lower technology. The EPA NSR Review Manual states that, "where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if any, between the application of the control technology on those sources and the particular source under review".

### **2.6.1 Average Cost Effectiveness.**

In the EPA's New Source Review Manual, page B.37, average cost effectiveness is calculated as:

$$\text{Average Cost Effectiveness} \text{ (\$ per ton removed)} = \frac{\text{Control option annualized cost}}{\text{Baseline emission rate} - \text{Control option emissions rate}}$$

The average cost effectiveness is based on the overall reduction in the air pollutant from the baseline emission rate. In the draft Workshop Manual, the EPA states that the baseline emission rate represents uncontrolled emissions for the source. However, the manual also states that when calculating the cost effectiveness of adding controls to inherently lower emitting processes, baseline emissions may be assumed to be the emissions from the lower emitting process itself.

### 2.6.2 Incremental Cost Effectiveness.

In addition to determining the average cost effectiveness of a control option, the U.S. EPA's New Source Review Manual states that the incremental cost effectiveness between dominant control options should also be calculated. The incremental cost effectiveness compares the costs and emissions performance level of a control option to those of the next most stringent control option:

$$\text{Incremental Cost (\$ per incremental ton removed)} = \frac{\text{Control option annualized cost} - \text{Next control option annualized cost}}{\text{Next control option emission rate} - \text{Control option emissions rate}}$$

### 2.6.3 Agency Decisions on Cost Effectiveness.

Numerous permitting authorities have made decisions regarding the economic feasibility of air pollution controls for coal-fired electric utility boilers which represent BACT. Table 2-1 is a summary of recent BACT economic analyses by various review agencies in which the control technology was rejected as not cost effective for BACT. The determinations in Table 2-1 include decisions for PM, PM<sub>10</sub>, NO<sub>x</sub>, and SO<sub>2</sub> emissions for biomass-fired boilers, pulverized coal-fired boilers, circulating fluidized bed boilers, and gas turbines. While cost effectiveness is determined on a case-by-case basis, the following information on comparative economic costs of BACT options gives some perspective on the costs that similar sources have typically *not* been expected to bear as BACT.

**TABLE 2-1. Summary of recent BACT economic analyses in which the control technology was rejected as not cost effective for BACT.**

1	Facility	State	Boiler Type	Pollutant	Control Technology Rejected	Cost Effectiveness of Rejected Technology, \$ per ton controlled		Control Technology Selected	Average Cost Effectiveness of Selected Technology, \$ per ton
						Average	Incremental		
1	DTE Energy – Stoneman Power Plant	WI	Stoker	NO <sub>x</sub>	SCR	\$9,217		SNCR	
2	We Energies – Concord Generating Station	WI	Gas Turb	NO <sub>x</sub>	SCR	8,236	-	Good Combustion	
3	Longleaf Energy Associates	GA	PC	SO <sub>2</sub>	Wet FGD	-	\$8,964	Dry FGD	\$724
4	Rocky Mountain Power Hardin	MT	PC	SO <sub>2</sub>	Wet FGD	\$1,395	\$23,855	Dry FGD	\$918
5	Intermountain Power 3	UT	PC	PM / PM <sub>10</sub>	Baghouse w/ Teflon Bags	\$31	\$14,000	Baghouse w/ Ryton Bags	\$31
6	Basin Electric – Dry Fork Station	WY	PC	NO <sub>x</sub>	SCR at 0.04	\$2,004	\$10,303	SCR at 0.05	\$1,511
				SO <sub>2</sub>	Wet FGD	\$1,595	\$15,299	Dry FGD	\$1,159
7	Black Hills Power & Light – WYGEN2	WY	PC	NO <sub>x</sub>	SCR at 0.06	\$4,156	\$7,742	SCR at 0.07	\$4,067
8	Black Hills Power & Light – WYGEN3	WY	PC	PM / PM <sub>10</sub>	Baghouse w/ Teflon Bags	\$134	\$14,609	Baghouse w/ Fiberglass Bags	\$130
9	Deseret Power Cooperative – Bonanza	UT	CFB	SO <sub>2</sub>	Wet FGD	\$418	\$10,540	Dry FGD	\$397
10	Southern Montana Electric Coop- Highwood	MT	CFB	SO <sub>2</sub>	Wet FGD	-	\$27,365	Ash Reinjection	\$4,054
					Dry FGD	-	\$7,939		
11	Montana-Dakota Utilities Gascoyne Station	ND	CFB	NO <sub>x</sub>	SCR	\$7,545	\$14,339	SNCR	\$2,926
12	Red Trail Energy Ethanol Plant	ND	CFB	SO <sub>2</sub>	Wet FGD	\$1,041	\$10,252	Dry FGD	\$527
13	River Hill Power Company	PA	CFB	SO <sub>2</sub>	Wet FGD	-	>\$5,000	Dry FGD	\$1,511
14	Cargill – Blair Ethanol Plant	NE	CFB	SO <sub>2</sub>	Dry FGD	-	\$5,900	No Post Controls	
15	ADM – Columbus Ethanol Plant	NE	CFB	NO <sub>x</sub>	SNCR	-	\$5,600	SNCR	\$2,174
				SO <sub>2</sub>	Ca Inj.	-	\$6,700		
16	Lakefield Junction Station	MN	CT	CO	Ox. Catalyst	3,400	-	No Post Controls	

1. In a PSD permit for the conversion of two coal-fired boilers to wood combustion, the Department concluded that the use of regenerative selective catalytic reduction with an average NO<sub>x</sub> control cost of \$9,217 per ton was not economically feasible.
2. In a PSD permit for 320 MW of simple cycle combustion turbine capacity, the Department concluded that the use of selective catalytic reduction with an average NO<sub>x</sub> control cost of \$8,236 per ton was not economically feasible.
3. In a PSD permit issued by the State of Georgia in 2006 for a new pulverized coal-fired utility boiler at Longleaf Energy Associates, Georgia determined that the incremental cost effectiveness of \$8,964/ton for wet FGD compared to dry FGD for SO<sub>2</sub> control was not cost effective. The average cost effectiveness of the selected BACT option, dry FGD, was \$724/ton. Georgia's PD is available online at: <http://www.air.dnr.state.ga.us/airpermit/psd/dockets/longleaf/permitdocs/0990030pd.pdf>.
4. In a PSD permit issued by the State of Montana in 2005 for a new pulverized coal fired utility boiler at Rocky Mountain Power's Hardin project, Montana concluded that an incremental cost effectiveness of \$23,855/ton for a wet FGD system as compared to a dry FGD system was excessive for BACT. The average cost effectiveness of the wet FGD option was \$1,395/ton. The average cost effectiveness of the selected BACT option, dry FGD, was \$918/ton. (Ref: Montana's Permit Analysis for Hardin project, Permit #3185-02, pages 15 and 17, dated May 16, 2005.)
5. In a PSD permit issued by the State of Utah in 2004 for a new pulverized coal-fired electric utility boiler at Intermountain Power's Unit 3, Utah concluded that an incremental cost effectiveness of \$14,000/ton to \$16,350/ton, comparing different types of baghouse fabric filter bags (Ryton-type bags versus specialty coated bags) for PM/PM<sub>10</sub> control, was excessive for BACT. The average cost effectiveness of the selected BACT option for PM<sub>10</sub> control (a baghouse with Ryton-type bags) was \$31/ton. (Ref: Utah's Modified Source Plan Review for IPP3 project, March 22, 2004, available online at: <http://www.airquality.utah.gov/Permits/PmtPowerPlants.htm>.)
6. In a PSD permit issued by the State of Wyoming in 2007 for a new pulverized coal-fired electric utility boiler at Basin Electric's Dry Fork Station, Wyoming concluded that an incremental cost effectiveness of \$23,755/ton for NO<sub>x</sub> control, comparing SCR at 0.043 lb/mmBtu to SCR at 0.040 lb/mmBtu, was excessive for BACT. The average cost effectiveness for SCR at 0.040 lb/mmBtu was \$2,004/ton; the average cost effectiveness for SCR at 0.043 lb/mmBtu was \$1,751/ton. Although Wyoming stated that an incremental cost effectiveness of \$10,303/ton was reasonable for SCR at 0.043 lb/mmBtu, for other reasons described by Wyoming the selected NO<sub>x</sub> control was SCR at 0.05 lb/mmBtu, with an incremental and average cost effectiveness of \$3,512/ton and \$1,511/ton, respectively.  
  
Wyoming also concluded that an incremental cost effectiveness of \$15,299/ton for SO<sub>2</sub> control, comparing a dry FGD system at 0.073 lb/mmBtu to a wet FGD at 0.054 lb/mmBtu, was excessive for BACT. The average cost effectiveness of the eliminated wet FGD option at 0.054 lb/mmBtu was \$1,595/ton. Although Wyoming determined that an incremental cost effectiveness of \$9,296/ton was reasonable for a dry FGD at 0.043 lb/mmBtu, for other reasons described by Wyoming the selected BACT option for SO<sub>2</sub> control was a dry FGD system at 0.08 lb/mmBtu, with an average cost effectiveness of \$1,159/ton. (Ref: Wyoming's Analysis for the Dry Fork project, NSR-AP-3546, February 5, 2007.)
7. In a PSD permit issued by the State of Wyoming in 2002 for a new pulverized coal-fired electric utility boiler at Black Hills Power & Light's WYGEN2 project, Wyoming concluded that an incremental cost effectiveness of \$7,742/ton, comparing low-NO<sub>x</sub> burners plus SCR at 0.06 lb/mmBtu to low-NO<sub>x</sub> burners plus SCR at 0.08 lb/mmBtu, for NO<sub>x</sub> control was reasonable for BACT. However, for other reasons described by Wyoming, the selected BACT option was low-NO<sub>x</sub> burners

plus SCR at 0.07 lb/mmBtu, with an average cost effectiveness between \$4,067/ton and \$4,156/ton. (Ref: Wyoming's Permit Application Analysis for the WYGEN2 project, NSR-AP-92, April 24, 2002.)

8. In a PSD permit issued by the State of Wyoming in 2006 for a new pulverized coal-fired electric utility boiler at Black Hills Power & Light's WYGEN3 project, Wyoming indicated that an incremental cost effectiveness of \$14,609/ton, comparing a baghouse with fiberglass or polyphenylene sulfide filter bags, listed as capable of achieving 0.012 lb/MmBtu, to a baghouse with specialty filter bags such as Teflon, listed as capable of achieving 0.011 to 0.010 lb/MmBtu, for PM/PM<sub>10</sub> control, was excessive for BACT. The average cost effectiveness of the selected BACT option, a baghouse with fiberglass or polyphenylene sulfide filter bags, was \$130/ton; the average cost effectiveness of the eliminated option, a baghouse with specialty filter bags, was \$134/ton. (Ref: Wyoming's Permit Application Analysis for the WYGEN3 project, NSR-AP-3934, October 9, 2006.)
9. In a PSD permit issued by the U.S. EPA Region 8 in August, 2007 for a circulating fluidized bed (CFB) boiler at the Deseret Power Cooperative's Bonanza Power Plant, the EPA concluded that an incremental cost of \$10,540 per ton of SO<sub>2</sub> removed to install a wet FGD system rather than a dry FGD system was too high to justify the expenditure. The average cost effectiveness for the wet FGD system was \$418 per ton of SO<sub>2</sub> controlled; the average cost effectiveness for the dry FGD system selected as BACT was \$397/ton of SO<sub>2</sub> controlled. Further, the EPA concluded that the costs for alternative sources of coal in lieu of waste coal of \$20,241 per ton of SO<sub>2</sub> controlled was also excessive as BACT.
10. In a PSD permit issued by the State of Montana in May, 2007 for a CFB boiler at Southern Montana Electric Cooperative's Highwood Generating Station, Montana concluded that a cost of \$27,365/ton of SO<sub>2</sub> control, for a combination of limestone injection, low-sulfur coal and wet FGD was excessive for BACT. Montana also concluded that a cost of \$7,939/ton of SO<sub>2</sub> controlled, for a combination of limestone injection, low-sulfur coal and dry FGD, was excessive for BACT. The selected SO<sub>2</sub> BACT option was a combination of limestone injection, low-sulfur coal, and hydrated ash reinjection with a cost effectiveness of \$4,054/ton. (Ref: Montana's "Permit Analysis" for Air Quality Permit #3423-00, May 30, 2007, from the Montana Department of Environmental Quality.)
11. In a PSD permit issued by the State of North Dakota in early 2005 for a CFB boiler at Montana-Dakota Utilities Gascoyne Generating Station, North Dakota concluded that an incremental cost effectiveness of \$14,339/ton, comparing SCR at 0.04 lb/mmBtu to SNCR at 0.09 lb/mmBtu, for NO<sub>x</sub> control, was excessive for BACT. The average cost effectiveness of SCR was \$7,545/ton. The average and incremental cost effectiveness of the selected BACT option, SNCR, was \$2,926/ton. (Ref: North Dakota's Permit Analysis, March 2005, North Dakota Department of Health, Environmental Health Section.)
12. In a PSD permit issued by the State of North Dakota in 2004 for a CFB boiler at the Red Trail Energy's Richardton, ethanol plant, North Dakota determined that an incremental cost effectiveness of \$10,252/ton, comparing wet FGD plus limestone injection to dry FGD plus limestone injection, for SO<sub>2</sub> control was not cost effective. The average cost effectiveness of wet FGD plus limestone injection was \$1,041/ton; the average cost effectiveness of dry FGD plus limestone injection was \$527/ton. North Dakota rejected wet FGD and determined that BACT is dry FGD plus limestone injection. (Ref: North Dakota's Analysis for Red Trail Energy project, May 2004, North Dakota Department of Health, Environmental Health Section, Air Quality Division.)
13. In a PSD permit issued by the State of Pennsylvania in 2005 for a CFB boiler at the River Hill Power Company, Pennsylvania concluded that all SO<sub>2</sub> BACT options involving wet FGD systems were economically infeasible at an incremental dollar per ton value greater than \$5,000 per ton of SO<sub>2</sub>

removed. Pennsylvania concluded that the use of dry FGD was economically feasible for the control of SO<sub>2</sub> at an incremental cost of \$1,511 per ton of SO<sub>2</sub> removed. Pennsylvania also concluded that an incremental cost effectiveness of \$15,975/ton, comparing the use of the waste coal to the nearest alternative source of coal with lower sulfur content, was excessive as BACT for SO<sub>2</sub> emissions. (Ref: Pennsylvania's "Plan Approval Review Memo, Application #17-00055A," May 2, 2005.)

14. In a PSD permit issued by the State of Nebraska in 2006 for a CFB boiler at Cargill's Blair ethanol production plant, Nebraska indicated that an incremental cost effectiveness of \$5,900/ton, comparing limestone injection alone to limestone injection plus dry FGD for SO<sub>2</sub> control, was excessive for BACT. (Ref: Nebraska permit CP06-0008, Sept. 8, 2006, available at [http://www.epa.gov/region07/programs/artd/air/nsr/archives/2006/finalpermits/cargill\\_blair\\_final\\_psd\\_permit.pdf](http://www.epa.gov/region07/programs/artd/air/nsr/archives/2006/finalpermits/cargill_blair_final_psd_permit.pdf).)
15. In a PSD permit issued by the State of Nebraska in 2006 for a CFB boiler at ADM's Columbus corn milling and ethanol production plant, Nebraska indicated that incremental cost effectiveness of \$5,600/ton for NO<sub>x</sub> control (comparing SNCR at 0.07 lb/mmBtu to SNCR at below 0.07), and an incremental cost effectiveness of \$6,700/ton for SO<sub>2</sub>/H<sub>2</sub>SO<sub>4</sub>/HF control (comparing limestone injection to "additional" limestone injection), were excessive for BACT. Nebraska listed incremental cost-effectiveness of \$2,174 for the selected BACT option for NO<sub>x</sub> control (SNCR at 0.07 lb/mmBtu). (Ref: Nebraska permit CPM02-0006, August 4, 2006, available online at: [http://www.epa.gov/region07/programs/artd/air/nsr/archives/2006/finalpermits/adm\\_columbus\\_final\\_psd\\_permit.pdf](http://www.epa.gov/region07/programs/artd/air/nsr/archives/2006/finalpermits/adm_columbus_final_psd_permit.pdf).)
16. In 2001, the Minnesota Pollution Control Agency considered the requirement to put oxidation catalysts on six 92 MW simple cycle combustion turbines at the Lakefield Junction Station, Trimont, MN. The following is from the Technical Support Document, Permit No. 09100058-001.

Whether or not either \$3400, or \$2938 per ton are reasonable control costs for CO control is arguable. The MPCA has decided, based on information submitted by the company and other sources, that both are unreasonable figures based on the following:

CO is a non-persistent pollutant. Attached is a portion of a report to congress that states that; "CO has a photochemical lifetime of about one month in the tropics; that lifetime becomes indefinitely long (and is controlled by transport) in the winter at high latitudes. The globally averaged destruction of CO corresponds to an estimated lifetime of 2.5 months." Therefore, emissions of CO from this facility will eventually become CO<sub>2</sub> on their own and an oxidation catalyst to speed the process is unnecessary in the absence of ambient impact concerns.

Ambient impacts are negligible. The air dispersion modeling performed for the facility predicts ambient impacts that are classified as insignificant under the Federal Prevention of Significant Deterioration regulations. Maximum predicted concentration of CO is 0.3% of the standard. (For Concord, the impacts are estimated at 0.01% of the NAAQS.)

CO ambient problems are primarily a transportation source issue. The National Air Quality and Emissions Trends Report from 1996 shows that transportation now accounts for 79 percent of the nation's total CO emissions. The attached graph from that report shows that non-transportation fuel combustion accounts for only 6.7% of overall CO emissions. CO emissions and ambient concentrations have been dropping since 1987 (and presumably prior as well) primarily due to measures taken to control emissions from mobile sources.

The Minnesota Public Utilities Commission externality hearings found that the costs to the environment attributable to CO emissions were \$0.021-0.041 per ton.



## **Chapter 3. Carbon Monoxide (CO) Control Technology Review.**

Carbon monoxide (CO) is emitted from natural gas-fired boilers as a result of incomplete combustion. Incomplete combustion can also result in reduced boiler efficiency and emissions of particulate matter, volatile organic compounds, and organic hazardous air pollutants. Because fuel costs represent the highest single operating cost for these boilers, these boilers are designed to achieve the highest combustion efficiencies practicable. CO emissions can be reduced by operating the boiler with higher furnace temperatures, higher excess oxygen levels, and longer furnace residence times. Unfortunately, techniques for reducing CO emissions can increase NO<sub>x</sub> emissions. Achieving low CO and low NO<sub>x</sub> emissions is therefore a balancing act in boiler design and operation.

### **3.1 BACT Baseline.**

There are no specific state implementation plan (SIP) requirements or new source performance standards for CO emissions from natural gas-fired boilers. Therefore, baseline emissions are simply the uncontrolled emissions from the boilers.

### **3.2 STEP 1. Identify All Available Control Technologies.**

Table 3-1 summarizes the CO BACT emission limits for new and modified natural gas-fired boilers in the U.S. EPA's RACT/BACT/LAER Clearinghouse. The technologies identified include Good Combustion Practices (GCP), and in one instance, Oxidation Catalysts (OC). Emission limits range from 0.035 to 0.14 lb/mmBtu for natural gas combustion. Please note that many of the emission limits in these tables were expressed as pounds per hour. These rates were converted to lb/mmBtu to make the emission limits comparable.

**TABLE 3-1. Natural gas-fired boiler carbon monoxide (CO) emission limits representing BACT from the U.S. EPA's RBLC database.**

<b>RBLC ID</b>	<b>FACILITY</b>	<b>PERMIT DATE</b>	<b>PROCESS</b>	<b>THRUPUT , mmBtu/hr</b>	<b>CONTROLS</b>	<b>LIMIT, lb/mmBtu</b>
OR-0040	Klamath Generation	03/12/03	Auxiliary Boiler			0.035
TN-0153	Williams Refining & Marketing, L.L.C.	04/03/02	Heater	9.1		0.035
LA-0229	Shintech Louisiana Plaquemine Plant 2	07/10/08	Utility Boilers	250.0	GCP	0.036
*GA-0127	Southern Company Plant McDonough	01/07/08	Auxiliary Boiler	200.0		0.037
OR-0046	Calpine Turner Energy Center	01/06/05	Auxiliary Boiler		OC	0.038
CO-0052	Rocky Mountain Energy Center.	08/11/02	Auxiliary Boiler	129.0	GCP	0.039
*AL-0230	Thyssenkrupp Steel And Stainless USA	08/17/07	3 Boilers	64.9		0.040
MN-0062	Heartland Corn Products	12/22/05	Boiler	198.0		0.040
WV-0023	Longview Power	03/02/04	Auxiliary Boiler	225.0	GCP	0.040
AR-0070	Genova Arkansas I	08/23/02	Auxiliary Boiler	33.0	GCP	0.040
AR-0026	Pine Bluff Energy Center	05/05/99	Boiler	362.0	GCP	0.044
SC-0049	Skygen Broad River Energy	12/02/99	Utility Boilers	230.0	GCP	0.060
TN-0153	Williams Refining & Marketing	04/03/02	WCR Heater	209.0		0.070
*ID-0017	Southeast Idaho Advanced Energy Center	02/10/09	Package Boiler	250.0	GCP	0.074
MN-0066	Northern States Power Riverside Plant	05/16/06	Auxiliary Boiler	160.0	GCP	0.080
WI-0228	Wisconsin Public Service - Weston	10/19/04	Auxiliary Boiler	229.8	GCP	0.080
OK-0045	Redbud Power Plant	08/15/01	Auxiliary Boiler	20.0	GCP	0.082
IN-0085	PSEG Lawrenceburg Energy	06/07/01	Auxiliary Boiler	124.6	GCP	0.082
AR-0055	Nucor Yamato Steel (Armored)	10/10/01	Process Heaters		GCP	0.082
TN-0153	Williams Refining & Marketing	04/03/02	Boiler, No. 9	95.0		0.090
AR-0057	Tenaska Arkansas Partners, LP	10/09/01	Boiler, (2)	122.0	GCP	0.110
NE-0024	Cargill - Blair Plant	06/22/04	Boiler	276.7	GCP	0.140

**Footnotes**

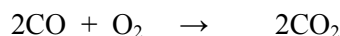
“GCP” means good combustion practices. “OC” means oxidation catalyst.

### 3.3 STEP 2. Identify Technically Feasible Control Technologies.

Available control technologies for the control of CO emissions include good combustion practices, oxidation catalysts, and thermal oxidation.

#### 3.3.1 Oxidation Catalysts.

Oxidation catalysts are used to reduce CO emissions from natural gas or oil-fired combustion turbines, with typical CO reductions of 50 – 90%. However, as indicated in Table 3.1, oxidation catalysts have limited demonstration in reducing CO emissions from natural gas boilers. The CO oxidation catalysts are generally noble metal catalysts which are susceptible to poisoning from sulfur and calcium bearing compounds. These catalysts may experience deactivation and fouling in high sulfur oil-fired boiler flue gas streams. To be effective, the oxidation catalyst must be placed in a location with gas temperatures of at least 600 °F. Oxidation catalysts operate according to the following general reaction:



Typical excess oxygen (O<sub>2</sub>) levels in combustion turbines is 12 – 15%, compared to 3 – 6% in natural gas-fired boilers. These low excess O<sub>2</sub> levels will limit the effectiveness of the oxidation catalyst.

#### 3.3.2 Thermal Oxidation

Thermal oxidation has never been required nor used on a natural gas-fired boiler, and its theoretical ability to reduce CO emissions from these boilers is questionable. Thermal oxidation would involve injecting additional air into the flue gas and heating the oxygen enriched mixture to approximately 1,500 °F to oxidize CO to carbon dioxide. However, since the combustion of the reheat fuel would itself result in CO emissions, there is no evidence that thermal oxidation would result in any CO emission reductions. Since thermal oxidation has never been demonstrated on a natural gas-fired boiler, and because there is no evidence that it could reduce CO emissions, thermal oxidation is not a technically feasible CO control technology for these boilers.

#### 3.3.3 Good Combustion Practices

Good combustion practices or combustion controls generally include the following components:

1. Good air/fuel mixing in the combustion zone.
2. High temperatures and low oxygen levels in the primary combustion zone.
3. Overall excess oxygen levels high enough to complete combustion while maximizing boiler thermal efficiency.
4. Sufficient residence time to complete combustion.

In natural gas-fired boilers, good combustion practices is a technically feasible CO control technology. Combustion efficiency is related to the three “T’s” of combustion: *Time, Temperature, and Turbulence*. These components of combustion efficiency are designed into utility boilers to maximize fuel efficiency

and reduce the highest single operating cost of a utility boiler: FUEL. A fourth critical parameter is the level of oxygen in the boiler, referred to as the excess air or excess oxygen level. Therefore, combustion control is accomplished primarily through boiler design as it relates to time, temperature, and turbulence, and through boiler operation as it relates to excess oxygen levels. Combustion design for modern boilers is intended to simultaneously minimize formation of CO and NO<sub>x</sub> emissions. This is a difficult task, since emissions of NO<sub>x</sub> and emissions of CO are inversely related. That is, measures used to reduce NO<sub>x</sub> emissions often lead to increases in CO emissions. Therefore, the boiler design to minimize CO emissions is interrelated with the boiler design to minimize NO<sub>x</sub> formation.

### **3.4 STEP 3. Rank the Technically Feasible Control Technologies.**

Based on the above analysis, the technically feasible CO control technologies for these natural gas-fired boilers includes good combustion practices based on the use of the ultra low NO<sub>x</sub> burners combined with flue gas recirculation, and the addition of an oxidation catalyst system as a post combustion control system. Good combustion practices are expected to limit CO emissions to less than 75 parts per million at 5% excess oxygen, equal to 0.06 lb/mmBtu. The use of an oxidation catalyst is expected to further reduce CO emissions by 50%, to 37 parts per million, and 0.03 lb/mmBtu.

### **3.5 STEP 4. Evaluate the Most Effective Controls.**

#### **3.5.1 Rank No. 1: Oxidation Catalyst and Good Combustion Practices.**

The use of good combustion practices combined with an oxidation catalyst on these natural gas-fired boilers could reduce CO emissions to 0.03 lb/mmBtu. Based on limiting the operation of these boilers to 6,200 hours per year, this combination of controls could reduce CO emissions from 32.6 tons per year, to 16.3 tons per year.

##### **3.5.1.1 Environmental Impacts.**

The primary environmental impact from the use of oxidation catalysts on these boilers is a reduction in CO emissions. The use of an oxidation catalyst may also reduce VOC emissions by 25%.

##### **3.5.1.2 Energy Impacts.**

Energy impacts from the use of an oxidation catalyst would include a small increase in induced draft fan power requirements necessary to overcome a small pressure drop across the catalyst.

##### **3.5.1.3 Economic Impacts.**

The costs for oxidation catalysts on these boilers would include the capital costs for the catalyst and ancillary equipment, labor, auxiliary power requirements, catalyst replacement, maintenance, and administrative costs. The oxidation catalyst cost analysis is included in Table 3-2. From Table 3-2, an oxidation catalyst system is expected to have an equipment cost of \$105,000 per boiler, and a total capital

requirement of \$210,000. From Table 3-2, the oxidation catalyst system is expected to have an annual cost of \$136,100 for each boiler. The oxidation catalyst systems would reduce CO emissions by 16.3 tons. Based on these costs, the oxidation catalyst systems would have an average cost effectiveness of \$8,360 per ton of CO removed.

**TABLE 3-2. Oxidation catalyst control system costs for each natural gas-fired boiler.**

	<b>CAPITAL COST</b>	<b>ANNUAL COST</b>
<b>Total Capital Cost</b>		
Equipment Cost, 2010 Dollars	\$105,000	
Capital Recovery Factor, CRF	0.1098	
<b>Total Capital Investment (TCI)</b>	<b>\$210,000</b>	<b>\$23,100</b>
<b>Labor Costs (1 hour per day)</b>		
		<b>\$18,300</b>
<b>Maintenance Costs</b>		
Maintenance Labor, hr/year	300	
Catalyst Inspection and Replacement Labor, hr per year	400	
Labor Cost, \$ per year	\$35,000	
Material Cost, \$ per year	\$35,000	
<b>Total Annual Maintenance Cost \$/yr</b>		<b>\$70,000</b>
<b>Catalyst Replacement Costs</b>		
Catalyst Cost	\$70,000	
Sinking Fund Factor	0.174	
<b>Total Catalyst Replacement Costs</b>		<b>\$12,200</b>
<b>Auxiliary Power Requirements</b>		
		<b>\$8,300</b>
<b>Overhead and Administrative Costs</b>		
	2% of TCI	<b>\$4,200</b>
<b>TOTAL ANNUAL COST</b>		<b>\$136,100</b>

**Footnotes**

1. The cost of capital for this project is 7%, and the project life is 15 years. The annual cost of this investment is given by the capital recovery factor (CRF):

$$CRF = \frac{i(1+i)^n}{[(1+i)^n - 1]} \quad \text{where:} \quad \begin{array}{l} i = \text{annual interest rate (decimal)} \\ n = \text{control system life (years)} \end{array}$$

2. For the catalyst, the catalyst life is 5 years. The annual cost is given by the sinking fund factor (SFF):

$$SFF = \frac{i}{[(1+i)^n - 1]}$$

3. The oxidation catalyst capital cost is based on the catalyst system equipment cost multiplied by 2.0 for the costs of installation and other necessary equipment..

### 3.5.1.4 Conclusion.

The use of an oxidation catalyst in combination with good combustion practices on these natural gas-fired package boilers can achieve CO emission rates of 0.03 lb/mmBtu. However, each oxidation catalyst system would have a total capital requirement of \$210,000, and a total annual cost of \$136,100. The oxidation catalyst systems would reduce CO emissions by 16.3 tons per year for each boiler, resulting in an average cost effectiveness of \$8,360 per ton of CO removed for each boiler. This is a very high cost, indicating that the use of an oxidation catalyst for the control of CO emissions on these natural gas-fired boilers is not an economically feasible control option.

Numerous regulatory agencies have made determinations regarding the cost effectiveness of oxidation catalysts on combustion turbines and have rejected this technology as economically infeasible at costs as low as \$1,700 per ton of CO removed. These determinations include the South Carolina Santee Cooper Rainey Generating Station, \$1,717 per ton; Mississippi MEP Clarksdale Power Plant, \$5,593 per ton; Florida Duke Energy Lake Station, \$5,563 per ton; Wisconsin West Marinette Station, \$6,053 per ton, and the Lakefield Junction Station, Trimont, MN, \$2,938 per ton. In 2001, the Minnesota Pollution Control Agency considered the requirement to put oxidation catalysts on six 92 MW combustion turbines at the Lakefield Junction Station, Trimont, MN. The following is from the Technical Support Document for this facility, Permit No. 09100058-001.

Whether or not either \$3400, or \$2938 per ton are reasonable control costs for CO control is arguable. The MPCA has decided, based on information submitted by the company and other sources, that both are unreasonable figures based on the following:

1. CO is a non-persistent pollutant. Attached is a portion of a report to congress that states that; "CO has a photochemical lifetime of about one month in the tropics; that lifetime becomes indefinitely long (and is controlled by transport) in the winter at high latitudes. The globally averaged destruction of CO corresponds to an estimated lifetime of 2.5 months." Therefore, emissions of CO from this facility will eventually become CO<sub>2</sub> on their own and an oxidation catalyst to speed the process is unnecessary in the absence of ambient impact concerns.
2. Ambient impacts are negligible. The air dispersion modeling performed for the facility predicts ambient impacts that are classified as insignificant under the Federal Prevention of Significant Deterioration regulations. Maximum predicted concentration of CO is 0.3% of the standard. ***(For this plant, the maximum CO ambient air impact for the entire Project is much less than the significant impact levels under NR 405, Wis. Adm. Code, indicating that these boilers will have an insignificant impact on ambient air concentrations .)***
3. CO ambient problems are primarily a transportation source issue. The National Air Quality and Emissions Trends Report from 1996 shows that transportation now accounts for 79 percent of the nation's total CO emissions. The attached graph from that report shows that non-transportation fuel combustion accounts for only 6.7% of overall CO emissions. CO emissions and ambient concentrations have been dropping since 1987 (and presumably prior as well) primarily due to measures taken to control emissions from mobile sources.
4. The Minnesota Public Utilities Commission externality hearings found that the costs to the environment attributable to CO emissions were \$0.021-0.041 per ton.

### **3.5.2 Rank No. 2: Good Combustion Practices.**

The use of package boilers with Ultra Low NO<sub>x</sub> Burners, Overfire Air, and Flue Gas Recirculation, and the use of good combustion practices can achieve a CO emission rate of 0.06 lb/mmBtu. Based on limiting the annual heat input to each boiler to no more than 1,085,000 mmBtu per year (equal to 2,170,000 mmBtu per year for both boilers combined), the use of good combustion practices will limit CO emissions from each boiler to 32.6 tons per year.

### **3.6 STEP 5. Proposed CO BACT Determination.**

Based on this analysis, We Energies has concluded that the use of good combustion practices represents the best available control technology (BACT) for the control of CO emissions from these natural gas-fired package boilers. Based on this analysis, We Energies proposes the following limits as BACT for the control of CO emissions from the natural gas-fired boilers.

- (1) Carbon monoxide (CO) emissions from the natural gas-fired boilers B02 and B03 shall be controlled using good combustion practices as the best available control technology.
- (2) Carbon monoxide (CO) emissions may not exceed 0.06 pounds per million Btu of heat input, based on a 30-day rolling average.
- (3) The total heat input to boilers B02 and B03 combined may not exceed 2,170,000 mmBtu in any consecutive 12-month period.



# Chapter 4. Nitrogen Oxides (NO<sub>x</sub>) Control Technology Review.

Nitrogen oxides (NO<sub>x</sub>) consist of several compounds, including nitrogen oxide (NO), and nitrogen dioxide (NO<sub>2</sub>). During combustion, NO usually accounts for more than 90% of the total NO<sub>x</sub> emissions. However, since NO is subsequently converted to NO<sub>2</sub> in the atmosphere, the mass emission rate of NO<sub>x</sub> are normally reported as NO<sub>2</sub>.

NO<sub>x</sub> is formed during combustion by two major mechanisms; thermal formation, called “Thermal NO<sub>x</sub>”, and fuel formation, called “Fuel NO<sub>x</sub>”. Thermal NO<sub>x</sub> results from the high temperature oxidation of nitrogen (N<sub>2</sub>) and oxygen (O<sub>2</sub>). Thermal NO<sub>x</sub> formation is influenced by the flue gas residence time and excess oxygen, but, as its name implies, thermal NO<sub>x</sub> formation is primarily influenced by temperature. Thermal NO<sub>x</sub> formation increases exponentially with temperature, and becomes significant at temperatures above 2800 °F. Fuel NO<sub>x</sub> results from the oxidation of organic nitrogen compounds in the fuel. Fuel bound nitrogen is more easily converted to NO<sub>x</sub> during combustion. Fuel NO<sub>x</sub> may account for up to 80% of the total NO<sub>x</sub> emissions, especially from solid fuel combustion.

## 4.1 BACT Baseline.

The proposed natural gas-fired boilers would be subject to the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units under 40 CFR Part 60, Subpart Db, and NR 440.205, Wis. Adm. Code. This subpart applies to steam generating units that commence construction, modification, or reconstruction after June 19, 1984, and that have a heat input capacity from fuels combusted in the steam generating unit greater than 100 mmBtu/hr.

The NO<sub>x</sub> standards in Subpart Db are specified by the type of fuel combusted. In NR 440.205(5)(a), the NO<sub>x</sub> emission limit is 0.20 lb/mmBtu for a high heat release boiler firing natural gas and distillate oil. This boiler will have a maximum heat release rate of more than 70,000 Btu/hr-ft<sup>3</sup>, a high heat release rate. Compliance with the NO<sub>x</sub> emission limit is to be determined on a 30-day rolling average basis and applies at all times, including startup, shutdown, and/or malfunction in accordance with 40 CFR 60.44b(i) and (h). Boilers with a heat input capacity of 250 mmBtu/hr or less with an annual capacity factor for natural gas and distillate oil greater than 10% can install a continuous monitoring system for NO<sub>x</sub> or can use operating conditions to predict emissions in accordance with 40 CFR 60.48b(g).

## 4.2 STEP 1. Identify All Potential Control Strategies.

Table 4-1 summarizes the NO<sub>x</sub> BACT emission limits for new and modified natural gas-fired boilers in the U.S. EPA's RACT/BACT/LAER Clearinghouse. The technologies identified include low NO<sub>x</sub> burners (LNB), Flue Gas Recirculation (FGR), Good Combustion Practices (GCP), and Selective catalytic reduction (SCR). Emission limits range from 0.01 to 0.10 lb/mmBtu for natural gas combustion. Please note that many of the emission limits in these tables were expressed as pounds per hour. These rates were converted to lb/mmBtu to make the emission limits comparable.

There are two major technology categories for controlling NO<sub>x</sub> emissions from boilers: combustion controls and post-combustion controls. Combustion NO<sub>x</sub> control techniques use technologies such as low NO<sub>x</sub> burners, and/or overfire air to control residence time, oxygen, and combustion temperature to limit NO<sub>x</sub> formation. Post combustion NO<sub>x</sub> control systems are designed to reduce emissions after NO<sub>x</sub> has been created. The most common secondary control technique involves the injection of ammonia or urea into the flue gas to reduce NO<sub>x</sub> to nitrogen and water. When injected upstream of a catalyst, this process is called Selective Catalytic Reduction (SCR); when injected without a catalyst, this process is called Selective Non-Catalytic Reduction (SNCR). Combustion and post combustion controls may be used together to achieve the lowest emission rates.

The following NO<sub>x</sub> control technologies were identified in a review of potential controls:

<b>Combustion Controls</b>	<ul style="list-style-type: none"> <li>• Low NO<sub>x</sub> burners (LNB)</li> <li>• Overfire air (OFA)</li> <li>• Flue Gas Recirculation (FGR)</li> <li>• Oxygen-Enhanced Combustion (OEC)</li> <li>• Fuel Reburn</li> </ul>
<b>Post Combustion Controls</b>	<ul style="list-style-type: none"> <li>• Selective Non-Catalytic Reduction (SNCR)</li> <li>• Selective Catalytic Reduction (SCR)</li> <li>• SCONO<sub>x</sub><sup>TM</sup></li> <li>• Emerging Control Technologies.</li> </ul>

**TABLE 4-1. Natural gas-fired boiler nitrogen oxides (NO<sub>x</sub>) emission limits representing BACT from the U.S. EPA's RBLC database.**

<b>RBLC ID</b>	<b>Facility</b>	<b>Permit Date</b>	<b>Process</b>	<b>Thruput, mmBtu/hr</b>	<b>Controls</b>	<b>Limit, lb/mmBtu</b>
LA-0229	Shintech Plaquemine Plant 2	07/10/08	Utility Boilers	250	LNB, SCR	0.010
TX-0499	Sandy Creek Energy Station	07/24/06	Auxiliary Boiler	175		0.010
OR-0046	Calpine Turner Energy Center	01/06/05	Auxiliary Boiler		SCR	0.011
PA-0193	Merck and Company - West Point Plant	08/26/99	Boilers, (2)	249	LNB, FGR, and SCR	0.012
*ID-0017	Southeast Idaho Advanced Energy Center	02/10/09	Package Boiler	250	LNB, FGR	0.020
MN-0076	Blandin Paper/Rapids Energy Center	09/18/08	Boiler	280	LNB, FGR	0.035
*AL-0230	Thyssenkrupp Steel and Stainless	08/17/07	3 Boilers	65	ULNB, FGR	0.035
NJ-0036	AES Red Oak, LLC	10/24/01	Auxiliary Boiler	120	Limit to 3,600 h/yr	0.036
IN-0085	PSEG Lawrenceburg Energy Facility	06/07/01	Auxiliary Boiler	125	LNB	0.036
AR-0026	Pine Bluff Energy Center	05/05/99	Boiler	362	LNB, FGR, GCP	0.037
CO-0052	Rocky Mountain Energy Center	08/11/02	Auxiliary Boiler	129	LNB, 1,900 h/yr	0.038
MN-0062	Heartland Corn Products	12/22/05	Boiler	198		0.040
ID-0015	J R Simplot Company - Don Siding Plant	04/05/04	Boiler	175	LNB	0.040
TX-0411	Calpine Amelia Energy Center	03/26/02	Auxiliary Boiler	155		0.040
SC-0049	Skygen Broad River Energy	12/02/99	Utility Boilers	230	LNB, FGR, GCP	0.040
ID-0015	J R Simplot Company - Don Siding Plant	04/05/04	Boiler	64	LNB	0.045
NE-0024	Cargill - Blair Plant	06/22/04	Boiler	277	LNB, FGR	0.050
IA-0050	Cargill - Eddyville	04/22/99	Boiler 7	182	LNB, FGR	0.050
AL-0128	Alabama Power - Theodore Cogeneration	03/16/99	Boiler	220	LNB, FGR	0.053
FL-0251	Okeelanta Corporation Sugar Mill	10/29/01	Boiler	211	LNB, FGR, GCP	0.060
NE-0024	Cargill - Blair Plant	06/22/04	Boilers A, B & C	198	LNB, FGR	0.070
LA-0183	Louisiana Pigment Co. Titanium Dioxide Facility	11/14/03	Utility Boilers	135	LNB, GCP	0.074
WI-0204	UWGP - Fuel Grade Ethanol Plant	08/14/03	Boiler /Oxidizer	140	GCP	0.095
WV-0023	Maidsville Longview Power, LLC	03/02/04	Auxiliary Boiler	225	LNB, GCP	0.098
WI-0228	Wisconsin Public Service - Weston Plant	10/19/04	Auxiliary Boiler	230	LNB, GCP	0.100
VA-0270	Virginia Commonwealth University East Plant	03/31/03	Boiler	150	LNB, FGR, GCP	0.100

**Footnotes**

“GCP” means good combustion practices. “SCR” means selective catalytic reduction. “LNB” means low NO<sub>x</sub> burner. “ULNB” means ultra-low NO<sub>x</sub> burner. “FGR” means flue gas recirculation.

## 4.3 STEP 2. Identify Technically Feasible Control Technologies.

There are two key concepts in determining the feasibility of potential control technologies: “availability” and “applicability.” A technology is considered “available” if it can be obtained commercially, has completed a commercial demonstration, and has reached the point of licensing. When considering a technology’s applicability, technical judgment must be exercised to determine if it can reasonably be installed and operated on the proposed source. In determining the feasibility of a given technology controlling to a given emission rate there is a third concept, “demonstrated in practice.” A control rate or emission rate is “demonstrated in practice” if a unit with similar operating conditions has continuously.

### 4.3.1 Low NO<sub>x</sub> Burners and Overfire Air.

Low NO<sub>x</sub> burners (LNB) are designed to control the mixing of air and fuel to reduce the peak temperatures of combustion in natural gas and fuel oil-fired boilers. Low NO<sub>x</sub> burners reduce NO<sub>x</sub> emissions by staging the combustion process. Staging slows down the combustion process, resulting in cooler flame temperatures which suppresses thermal NO<sub>x</sub> formation.

Low NO<sub>x</sub> burners are designed to control fuel and air mixing at the burner in order to create larger flame patterns. This reduces the peak flame temperature and results in lower thermal NO<sub>x</sub> formation. The modified flame structure also reduces the amount of oxygen available in the hottest part of the flame, improving burner efficiency. Primary combustion, NO<sub>x</sub> reduction and fuel burnout are accomplished in three stages in a modern, LNB equipped boiler:

1. The first stage is a fuel rich zone where oxygen levels are maintained below the stoichiometric requirement to complete combustion. Most NO<sub>x</sub> is formed in this zone.
2. The second stage is a reducing zone where unburned hydrocarbon radicals reduce the NO<sub>x</sub> formed in the first stage.
3. In the third stage, overfire air completes combustion, but produces additional NO<sub>x</sub>. The NO<sub>x</sub> formation is minimized by completing combustion in an air-lean environment.

Some LNBs include the installation of over-fire air ports that provide sufficient oxygen to complete the combustion process, but at temperatures well below those found in the burner flame. This is more common in solid fuel combustion. For natural gas and fuel oil combustion, this deep staging of overfire air is not required. Instead, the staging of combustion is done within the burner itself.

LNB and ultra low NO<sub>x</sub> burners are an available and highly effective NO<sub>x</sub> control technology for these natural gas-fired boilers. These burners are capable of limiting NO<sub>x</sub> emissions to approximately 9 parts per million (ppm). A typical, modern ultra low NO<sub>x</sub> burner for natural gas and distillate fuel oil combustion is shown in Figure 4-1.

**FIGURE 4-1. A typical, modern ultra-low NO<sub>x</sub> burner for natural gas combustion (from Cleaver-Brooks NATCOM®).**



#### **4.3.2 Overfire Air (Staged Combustion).**

Overfire air (OFA) is a combustion staging process typically used in conjunction with low NO<sub>x</sub> burners. A portion of the combustion air is redirected from the LNB to a higher elevation in the furnace to reduce peak flame temperatures by reducing the concentration of oxygen in portions of the furnace. This technique is used to create an oxygen depleted zone where unburned hydrocarbon species act to reduce the NO<sub>x</sub> that was formed near the burner. The overfire air creates an oxidation zone to complete combustion. NO<sub>x</sub> formation is minimized by completing combustion in an air-lean environment.

#### **4.3.3 Flue Gas Recirculation.**

Flue gas recirculation (FGR) is a combustion process often used in conjunction with low NO<sub>x</sub> burners to reduce peak flame temperatures and create an oxygen depleted zone in the boiler by reducing the concentration of oxygen in portions of the furnace. Flue gas recirculation reduces the oxygen content of the air at the base of the furnace by diluting the primary air blown into the furnace with recirculated flue gas from the back pass of the boiler. This technique is used to create an oxygen depleted reducing zone where unburned hydrocarbon species act to reduce the NO<sub>x</sub> that was formed near the burner. This oxygen depleted zone also reduces the peak flame temperatures which minimizes NO<sub>x</sub> formation.

#### 4.3.4 Oxygen-Enhanced Combustion.

Oxygen-Enhanced Combustion (OEC) is a combustion control technology aimed at reducing the formation of thermal NO<sub>x</sub>. Praxair Technology, Inc. has developed a method of using oxygen to achieve additional NO<sub>x</sub> reduction from low NO<sub>x</sub> burners on pulverized coal-fired boilers. Field tests were conducted at the James River Power Station Unit 3, a wall-fired boiler. In pilot- and full-scale testing, NO<sub>x</sub> emissions were reduced by as much as 60%, to levels below 0.15 lb/mmBtu, when a small portion of low-NO<sub>x</sub> burner combustion air was replaced with locally injected oxygen.

We are not aware of the use of OEC on natural gas-fired boilers. Because there is no operational experience with OEC on these boilers, and because the application of OEC to these boilers has significant technological questions, OEC is not a technically feasible control option.

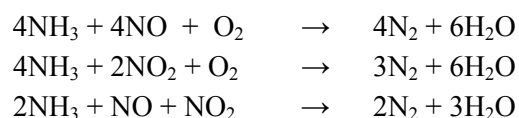
#### 4.3.5 Natural Gas or Coal Reburning

Natural gas or coal reburning are NO<sub>x</sub> control techniques used primarily for reducing NO<sub>x</sub> emissions from existing utility scale coal-fired boilers. Reburning redistributes a portion of both fuel and air into the upper regions of the boiler furnace to create a second flame zone, generating chemically reducing conditions that destroy NO<sub>x</sub> in the primary combustion zone. In large utility pulverized coal-fired boilers, fuel reburning is conducted between the upper burner row and the furnace exit. Most reburn systems divert 10 to 20% of the total boiler heat input to the upper furnace. If reburn conditions are not carefully controlled, high temperature corrosion problems can occur which can damage the boiler.

At least five utility coal-fired demonstrations of reburn are in different levels of operation. In the best applications, reburning may reduce NO<sub>x</sub> emissions to 0.15 lb/mmBtu. However, to be effective in reducing NO<sub>x</sub> emissions, reburning requires a large furnace volume to adequately stage combustion. This natural gas and/or coal reburning process is not applicable to natural gas-fired boilers. Therefore, natural gas and coal reburning are not technically feasible control options.

#### 4.3.6 Selective Catalytic Reduction.

Selective Catalytic Reduction (SCR) is a post combustion NO<sub>x</sub> control system which consists of an ammonia (NH<sub>3</sub>) injection system and a catalytic reactor. Urea can be decomposed in an external reactor to form ammonia for use in an SCR. The ammonia injection grid is located upstream of the catalyst. Ammonia reacts with NO<sub>x</sub> and O<sub>2</sub> in the presence of the catalyst to form molecular nitrogen (N<sub>2</sub>) and water according to the following general equations:



This process is called “selective” because ammonia reacts preferentially with NO<sub>x</sub> in the flue gas in the presence of a catalyst. A catalyst is used to enhance NO<sub>x</sub> reduction and ammonia utilization. The most common catalyst is a vanadium-based material supported on a honeycomb substrate that is installed in

multiple layers in the catalytic reactor. Secondary reactions also occur in the presence of the SCR catalyst, including the oxidation of SO<sub>2</sub> to SO<sub>3</sub> and the oxidation of elemental mercury.

Based on this review, SCR is a technically feasible control option for these natural gas-fired boilers.

#### **4.3.7 Selective Non-Catalytic Reduction.**

In a selective non-catalytic reduction (SNCR) control system, urea or ammonia is injected into the boiler where the flue gas temperature is approximately 1,600 °F to 2,100 °F. At these temperatures, the reagent, urea [CO(NH<sub>2</sub>)<sub>2</sub>] or ammonia [NH<sub>3</sub>], reacts with NO<sub>x</sub>, forming elemental nitrogen [N<sub>2</sub>] and water without the need for a catalyst. The overall NO<sub>x</sub> reduction reactions are similar to those for the SCR systems. Multiple injection points are required to thoroughly mix the reagent in the boiler furnace. The limiting factor for a SNCR system is the ability to contact the NO<sub>x</sub> with the reagent as the concentration decreases without resulting in excessive ammonia slip, and without excessive ammonia decomposition before the NO<sub>x</sub> emissions can be reduced.

SNCR has been widely used in fluidized bed boilers where the high alkaline ash loading of the CFB boilers makes 'high dust' loading SCR systems technically infeasible. SNCR has also been widely used in modern stoker boilers. However, SNCR is not appropriate for use in package natural gas-fired boilers, since the short residence time does not allow for adequate reaction time to reduce NO<sub>x</sub> emissions. Therefore, SNCR is not a technically feasible control option for these boilers.

#### **4.3.8 Catalytic Absorption/Oxidation (SCONOx™)**

SCONOx™ is a control technology that has been applied in combustion turbine applications. ABB Alstom Power purchased a proprietary technology called SCONOx™ from Goal Line Environmental Technologies. A SCONOx system has been in operation since December of 1996 on the 30 MW Sun Law Energy Federal cogeneration plant in Vernon, California. Since August of 1999, SCONOx has been in operation on a 5 MW cogeneration plant at Genetics Institute in Andover, Massachusetts. ABB Alstom Power subsequently completed design of a scaled-up SCONOx system for 100 MW and greater combined cycle gas turbines.

The SCONOx system is based on a proprietary catalytic oxidation and absorption technology. In operation, NO and CO are first oxidized to NO<sub>2</sub> and CO<sub>2</sub>. Next, NO<sub>2</sub> is adsorbed onto an adsorption media. When the media is saturated, NO<sub>2</sub> is desorbed and treated by the proprietary catalyst. Because the operation of SCONOx to oxidize CO to CO<sub>2</sub> is identical to the simple use of an oxidation catalyst, there is effectively no difference between SCONOx and an oxidation catalyst in terms of CO and VOC control. Therefore, SCONOx and an oxidation catalyst are effectively the same technology for controlling CO and VOC emissions.

To date, SCONOx has only been installed on small scale natural gas-fired combustion turbines. Therefore, this technology is not technically feasible for these boilers. Even if one were to conclude that it is applicable to these natural gas-fired boilers, the controlled emission rates would be similar to the use of SCR.

### 4.3.9 Emerging Control Technologies.

Emerging technologies to reduce NO<sub>x</sub> emissions include Enviroscrub, Powerspan's Electro-Catalytic Oxidation (ECO™) scrubber, and the NOxStar and Cascade processes. Enviroscrub and ECO are emerging technologies with the potential to reduce NO<sub>x</sub> emissions and potentially other pollutants as well. However, these technologies are either not yet commercially available or are not proven with a long term demonstrated level of performance. The most advanced process is the ECO system. ECO™ is an emerging post-combustion multi-pollutant control technology including NO<sub>x</sub> control and has demonstrated performance, reliability and economics through testing at a pilot plant. However, no full size commercial scale ECO™ systems have been installed or operated.

Enhanced and hybrid SNCR and SCR systems that are emerging NO<sub>x</sub> control technologies include NOxStar and Cascade. NOxStar is a hydrocarbon enhanced SNCR system that injects hydrocarbons downstream of an SNCR system to produce radicals that will further reduce NO<sub>x</sub> emissions. The Cascade process is a hybrid combination of SNCR and SCR systems. Neither of these systems has demonstrated long term levels of performance, and neither of them has been demonstrated on a full scale boiler. Due to lack of experience and a proven record of commercial operation, these emerging control technologies are not technically feasible for NO<sub>x</sub> control for these boilers.

### 4.3.10 Summary of the Technically Feasible Controls.

Table 4-2 is a summary of the technical feasibility of the NO<sub>x</sub> controls for the proposed natural gas-fired boilers.

**TABLE 4-2. Summary of the technical feasibility of retrofit NO<sub>x</sub> control technologies.**

Technology	Technical Feasibility	
Low NO <sub>x</sub> Burners (LNB)	Yes	LNB are widely used in natural gas-fired package boilers.
Overfire Air (OFA)	Yes	OFA is a design feature of modern natural gas-fired package boilers.
Flue Gas Recirculation (FGR)	Yes	FGR is a design feature of modern natural gas-fired package boilers.
Oxygen Enhanced Combustion	No	Never applied to natural gas-fired package boilers.
Natural Gas or Coal Return	No	Never applied to natural gas-fired package boilers.
Selective Non-Catalytic Reduction (SNCR)	No	SNCR is not applicable to natural gas-fired package boilers.
Selective Catalytic Reduction (SCR)	Yes	SCR has been demonstrated on both natural gas-fired boilers.

## 4.4 STEP 3. Rank the Technically Feasible Control Technologies.

Table 4-3 is a summary of the ranking of the technically feasible NO<sub>x</sub> control technologies for the proposed natural gas-fired boilers. While SCR systems can be designed to reduce NO<sub>x</sub> emissions by 90%, the use of SCR systems cannot be expected to achieve this reduction efficiency on a long term basis. For natural gas combustion, the SCR is expected to reduce NO<sub>x</sub> emissions to 0.01 lb/mmBtu, or a NO<sub>x</sub> emission rate of 7 parts per million (ppm) at 5% excess oxygen.

**TABLE 4-3. Ranking of the technically feasible NO<sub>x</sub> control technologies.**

Control System	Expected Emission Rate, lb/mmBtu
Package Boiler with Ultra Low NO <sub>x</sub> Burners, Overfire Air, and Flue Gas Recirculation, and Selective Catalytic Reduction	0.01
Package Boiler with Ultra Low NO <sub>x</sub> Burners, Overfire Air, and Flue Gas Recirculation	0.02

## 4.5 STEP 4. Evaluate the Most Effective Controls

### 4.5.1 Rank No. 1: Selective Catalytic Reduction.

The use of an SCR can achieve a NO<sub>x</sub> emission rate of 0.01 lb/mmBtu for these natural gas-fired boilers. Based on limiting the operation of each boiler to 6,200 hours per year, the SCR system could reduce NO<sub>x</sub> emissions from 10.9 tons per year for the boiler with ultra low NO<sub>x</sub> burners, to 5.5 tons per year, equal to a reduction of 5.5 tons per year.

#### 4.5.1.1 Environmental Impacts.

The primary environmental impact from the use of SCR on these boilers is a reduction in NO<sub>x</sub> emissions. The use of SCR would also have adverse environmental impacts. Ammonia slip emissions from the operation of the SCR system would result in direct emissions of ammonia and ammonium nitrate. Ammonia will react with sulfate in the atmosphere to form ammonium sulfate. Ammonium sulfate and ammonium nitrate are predominant sources of regional haze, and contribute to PM<sub>2.5</sub>.

#### 4.5.1.2 Energy Impacts.

Energy impacts from the use of SCR would include the increased electric energy required for the induced draft fans overcome the increase in pressure drop across the SCR system.

**TABLE 4-4. Estimated SCR NO<sub>x</sub> control system costs for each natural gas-fired boiler.**

	<b>CAPITAL COST</b>	<b>ANNUAL COST</b>
<b>Total Capital Cost</b>		
Total Equipment Cost, 1999 Dollars	\$393,240	
Total Capital Cost, 1999 Dollars	\$668,508	
Total Capital Cost, 2009 Dollars	\$864,342	
Capital Recovery Factor, CRF	0.1098	
<b>Total Capital Investment (TCI)</b>	<b>\$864,300</b>	<b>\$94,900</b>
<b>Reagent (19% Aqueous Ammonia) Costs</b>		
Ammonia Cost (\$1.30 per gal for 19% ammonia), \$ per ton	\$1,620	
Uncontrolled NO <sub>x</sub> Emissions, ton/yr	10.9	
Moles ammonia per mole NO <sub>x</sub>	1.1	
<b>Total Reagent Costs</b>		<b>\$7,500</b>
<b>Total Labor Costs (2 hr per day)</b>		<b>\$36,500</b>
<b>Maintenance Costs</b>		
Maintenance Labor, hr/year	365	
Catalyst Inspection and Replacement Labor, hr per year	400	
Labor Cost, \$ per year	\$38,250	
Material Cost, \$ per year	\$38,250	
<b>Total Annual Cost (\$/yr)</b>		<b>\$76,500</b>
<b>Catalyst Replacement Costs</b>		
Catalyst Cost	\$190,000	
Sinking Fund Factor	0.174	
<b>Total Catalyst Replacement Costs</b>		<b>\$33,000</b>
<b>Total Overhead and Administrative Costs</b>	2% of TCI	<b>\$17,300</b>
<b>TOTAL ANNUAL COST</b>		<b>\$248,400</b>

***Footnotes***

1. The cost of capital for this project is 7%, and the project life is 15 years. The annual cost of this investment is given by the capital recovery factor (CRF):

$$CRF = \frac{i(1+i)^n}{[(1+i)^n - 1]} \quad \text{where:} \quad \begin{array}{l} i = \text{annual interest rate (decimal)} \\ n = \text{control system life (years)} \end{array}$$

2. For the catalyst, the catalyst life is 5 years. The annual cost is given by the sinking fund factor (SFF):

$$SFF = \frac{i}{[(1+i)^n - 1]}$$

3. The SCR capital cost is the cost for a 150 mmBtu/hr boiler as given in the U.S. EPA NO<sub>x</sub> ACT document, Appendix A.2.3., available at <http://www.epa.gov/ttn/nsr/gen/appendix.pdf>. The CPI was used to escalate the costs to 2010.

#### **4.5.1.3 Economic Impacts.**

The costs for SCR controls on these boilers would include the capital costs for the SCR and ancillary equipment, labor, auxiliary power requirements, ammonia, catalyst replacement, maintenance, and administrative costs. The SCR cost analysis is included in Table 4-4. From Table 4-4, an SCR system is expected to have a total capital requirement of \$864,000 and a total annual cost of \$248,400. The SCR system would reduce NO<sub>x</sub> emissions from each boiler by 5.4 tons per year. Based on these costs, the SCR system would have an average cost effectiveness of \$45,800 per ton of NO<sub>x</sub> removed.

#### **4.5.1.4 Conclusion.**

The use of SCR on these natural gas-fired package boilers can achieve NO<sub>x</sub> emission rates of 0.01 lb/mmBtu. However, each SCR system would have a total capital requirement of \$864,000, and a total annual cost of \$246,000. The SCR system would reduce NO<sub>x</sub> emissions from each boiler by 5.4 tons per year, resulting in an average cost effectiveness of \$45,800 per ton of NO<sub>x</sub> removed. These costs are very high, indicating that the use of SCR on these natural gas-fired boilers is not an economically feasible control option.

#### **4.5.2 Rank No. 2: Package Boiler with Ultra Low NO<sub>x</sub> Burners.**

The use of package boilers with Ultra Low NO<sub>x</sub> Burners, Overfire Air, and Flue Gas Recirculation can achieve a NO<sub>x</sub> emission rate of 0.02 lb/mmBtu.

### **4.6 STEP 5. Proposed Nitrogen Oxide BACT Determination.**

Based on this analysis, We Energies has concluded that the use of package boilers with Ultra Low NO<sub>x</sub> Burners, Overfire Air, and Flue Gas Recirculation is the best available control technology (BACT) for NO<sub>x</sub> emissions from the natural gas-fired boilers B02 and B03. Based on this analysis, We Energies proposes the following limits as BACT for the control of NO<sub>x</sub> emissions from these boilers.

- (1) Nitrogen oxide (NO<sub>x</sub>) emissions from the natural gas-fired boilers B02 and B03 shall be controlled using Ultra Low NO<sub>x</sub> Burners, Overfire Air, and Flue Gas Recirculation as the best available control technology.
- (2) Nitrogen oxide (NO<sub>x</sub>) emissions may not exceed 0.02 pounds per million Btu of heat input, averaged over any consecutive 30-day period.
- (3) The total heat input to boilers B02 and B03 combined may not exceed 2,170,000 mmBtu in any consecutive 12-month period.



# Chapter 5. Particulate Matter and PM<sub>10</sub> Control Technology Review.

Particulate matter (PM) emissions from natural gas-fired boilers originate from ash in the fuel, and from products of incomplete. In Wisconsin, “particulate matter emissions” are defined under NR 400.02(119), Wis. Adm. Code, as:

(119) “Particulate matter emissions” means all finely divided solid or liquid material, other than uncombined water, emitted to the ambient air as measured by an applicable reference method or an equivalent or alternative method specified by the department.

Based on this definition, PM may be solid or liquid materials. PM which exists as a solid or liquid at temperatures of approximately 250 °F are measured using U.S. EPA’s Reference Method (RM) 5, and are referred to as “front half” emissions. PM which exists as a solid or liquid at the lower temperature of 32 °F are measured using U.S. EPA’s RM 202, and is commonly referred to as “back half” or “condensable” PM. Condensable PM may include acid gases, volatile organic compounds (VOC) and other materials, but by definition does not include condensed water vapor. Because of these different temperatures at which PM emissions are measured, the amount of PM measured depends on the reference methods used.

## 5.1 BACT Baseline.

The natural gas-fired boilers will be subject to the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units under 40 CFR Part 60, Subpart Db. This subpart applies to steam generating units that commence construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit greater than 100 mmBtu/hr. The only NSPS PM standard that is applicable to similar natural gas and distillate fuel oil-fired boilers is the opacity standard when fuel oil is fired under 40 CFR 60.43b(f) and NR 440.205(4)(f). This paragraph limits the opacity of emissions when distillate fuel oil is fired to no more than 20% (6-minute average). The exception is one 6-minute period per hour with opacity may not exceeding 27%. Because these are natural gas-fired boilers, this opacity standard does not apply.

## 5.2 STEP 1. Identify Potential Control Technologies.

Table 5-1 summarizes the particulate matter BACT emission limits for new and modified natural gas-fired boilers in the U.S. EPA’s RACT/BACT/LAER Clearinghouse. The only technologies identified include good combustion practices and the use of clean fuels including natural gas. Emission limits range from 0.002 to 0.08 lb/mmBtu for natural gas combustion. Please note that many of the emission limits in these tables were expressed as pounds per hour. These rates were converted to lb/mmBtu to make the emission limits comparable.

**TABLE 5-1. Natural gas-fired boiler particulate matter emission limits representing BACT from the U.S. EPA's RBLC database.**

<b>RBLC ID</b>	<b>Facility</b>	<b>Permit Date</b>	<b>Process</b>	<b>Thruput, mmBtu/hr</b>	<b>Controls</b>	<b>Limit, lb/mmBtu</b>
WV-0023	Longview Power, LLC - Madsville	03/02/04	Auxiliary Boiler	225	GCP, Clean Fuels	0.0022
OR-0040	Klamath Generation, LLC	03/12/03	Auxiliary Boiler			0.0042
AR-0026	Pine Bluff Energy LLC-Pine Bluff Energy Center	05/05/99	Boiler	362	GCP, Clean Fuels	0.0050
AR-0057	Tenaska Arkansas Partners, LP	10/09/01	Boiler	122	GCP	0.0050
TX-0499	Sandy Creek Energy Station	07/24/06	Auxiliary Boiler	175		0.0050
*ID-0017	SE Idaho Power County Energy Center	02/10/09	Package Boiler	250	GCP	0.0052
NJ-0042	Roche Vitamins	02/05/99	Boiler	134	None Listed	0.0052
NJ-0036	AES Red Oak, LLC	10/24/01	Auxiliary Boiler	120	GCP	0.0066
TX-0414	Atofina Petrochemicals Port Arthur Complex	04/22/99	Supplement Boiler	227	Low Ash Fuel	0.0070
OK-0045	Redbud Power Plant	08/15/01	Auxiliary Boiler	20	Low Ash Fuel, GCP	0.0074
NC-0101	Forsyth Energy Plant	09/29/05	Auxiliary Boiler	110	LNB, GCP	0.0074
IN-0085	PSEG Lawrenceburg Energy Facility	06/07/01	Auxiliary Boiler	125	GCP	0.0074
WI-0228	Wisconsin Public Service - Weston Plant	10/19/04	Auxiliary Boiler	230	GCP, Natural Gas	0.0075
TN-0153	Williams Refining & Marketing, LLC	04/03/02	Boiler	180		0.0075
OH-0310	American Municipal Power Generating Station	02/07/08	Auxiliary Boiler	150		0.0076
*AL-0230	Thyssenkrupp Steel & Stainless USA, LLC	08/17/07	3 Boilers	65	ULNB, FGR	0.0076
MS-0069	Dupont Delisle Facility	06/08/04	Boiler	231	Natural Gas	0.0076
VA-0278	Virginia Commonwealth University East Plant	03/31/03	3 Boilers	151		0.0080
AL-0128	Alabama Power Co. - Theodore Cogeneration	03/16/99	Boiler	220	Natural Gas	0.0080
VA-0270	Virginia Commonwealth University East Plant	03/31/03	Boiler	150	GCP	0.0080
NJ-0043	Liberty Generating Station	03/28/02	Auxiliary Boiler	200		0.0080
MN-0039	Minnesota Corn Processors	08/08/00	Boiler	237	Natural Gas Only	0.0084
AR-0070	Genova Arkansas I, LLC	08/23/02	Auxiliary Boiler	33	GCP	0.0120
NJ-0042	Roche Vitamins	02/05/99	Boiler	84		0.0142
TX-0386	Calpine Amella Energy Center	03/26/02	Auxiliary Boiler	155		0.0208
WI-0204	United Wisconsin Grain Producers- Ethanol Plant	08/14/03	Boiler	140		0.0393
NJ-0042	Roche Vitamins	02/05/99	Boiler	118	None Listed	0.0864

**Footnotes**

“GCP” means good combustion practices. “SCR” means selective catalytic reduction. “LNB” means low NOx burner. “ULNB” means ultra-low NOx burner. “FGR” means flue gas recirculation.

## 5.3 STEP 2. Identify Technically Feasible Control Technologies.

As noted above, data from the U.S. EPA's RBLIC indicate that the only technologies selected as BACT for new natural gas-fired boilers include good combustion practices and the use of clean fuels including natural gas. Other PM controls include fabric filter baghouses, electrostatic precipitators, and mechanical collectors such as multicyclones, and wet venturi scrubbers.

### 5.3.1 Fabric Filter Baghouses.

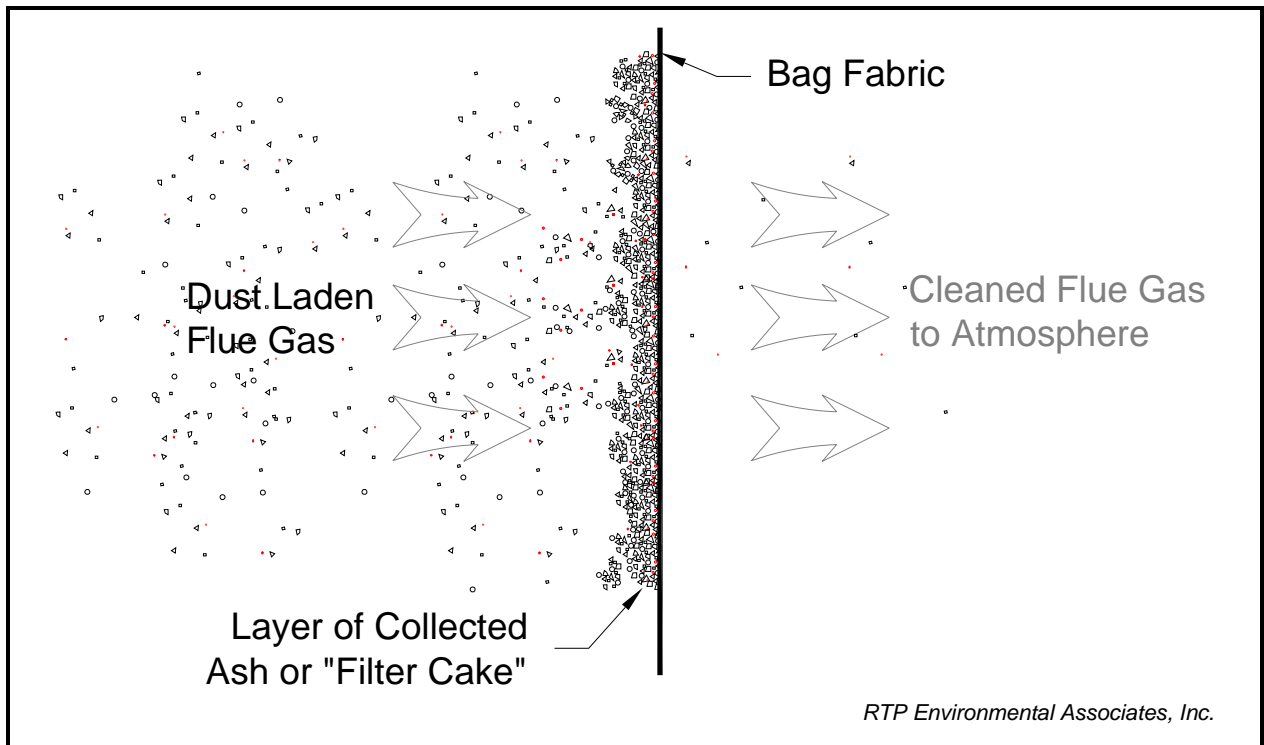
A fabric filter baghouse (FFB) separates dry particles from the boiler flue gas by filtering the flue gas through fabric filters or "bags". The components of a FFB include the fabric filters, a tube sheet to support the bags, a gas-tight enclosure, a mechanism to clean accumulated PM from the bags, and a hopper to collect accumulated ash. Baghouses are compartmentalized to facilitate cleaning and to provide for maintenance and repair. When the pressure drop across a compartment increases to a specified limit, the accumulated PM is removed by placing that compartment in the cleaning mode.

PM laden flue gas enters the FFB and passes through the bags. As the flue gas flows through the fabric filter media, a layer of collected material, called the "filter cake", builds up on the fabric. Both the filter media and the filter cake are important for the particulate filtration performance of the baghouse. For woven filter media, the filter cake is actually the primary control mechanism. Particles are collected on the filter cake through impaction and interception in a mechanism called "sieving". In addition, the filter cake acts like a fixed-bed reactor. The ash collected in the filter cake has active reagents such as calcium oxide (CaO) and unburned carbon which can react with gaseous air pollutants as they pass through the filter cake. This baghouse mechanism contributes to greater absorption and control of air pollutants including sulfur dioxide (SO<sub>2</sub>), sulfuric acid mist, and hazardous air pollutants including mercury, hydrogen chloride (HCl), and hydrogen fluoride (HF). A depiction of the mechanism for particulate removal on the filter media is shown in Figure 5-1.

FFB have several methods for cleaning, including reverse gas (RGFFB), reverse air with mechanical shakers, and pulse jet (PJFFB). In a RGFFB, the fly ash is collected on the *inside* of the bags. Each compartment of a RGFFB is periodically taken out of service for cleaning by circulating clean flue gas from the outlet plenum backward through the offline compartment. This dislodges the collected dust, which falls into hoppers. In a PJFFB, the fly ash is collected on the outside of the bags. Cleaning is normally accomplished on line by directing a pulse of air backward through the bag. The air pulse dislodges the fly ash, which falls into hoppers. A PJFFB can operate at higher air-to-cloth ratios than a RGFFB. However, because the pulse jet cleaning method is more aggressive than in the RGFFB, the bags in a RGFFB normally have a longer service life.

FFBs have several important advantages when used for PM control from coal-fired boilers, including high particulate matter control efficiencies which are largely independent of fuel characteristics, relatively constant outlet grain loading over the entire boiler load range, and simple operation and maintenance. The primary disadvantage of fabric filter baghouses is the relatively high pressure drop across the baghouse as compared to a dry ESP and the resulting increased fan power requirements.

**FIGURE 5-1. Depiction of the flue gas flow through the fabric filter baghouse filter cake showing the mechanism for particulate collection.**



### 5.3.2 Dry Electrostatic Precipitators.

Electrostatic precipitators (ESP) are a common PM control system for both coal and biomass-fired boilers. However, ESPs are not normally used on natural gas-fired boilers. An ESP uses a large enclosure to slow the gas stream, which allows more time to electrostatically charge particulates and collect them in the ESP. An ESP is arranged in a series of fields which consist of negatively charged discharge electrodes and positively charged collection plates. The discharge electrodes impart a negative charge to particles in the gas stream. The negatively charged particles then migrate to the larger positively charged plates. PM collected on the plates is periodically removed by rapping the plate. Most of the PM knocked off the plates falls into collection hoppers for removal. A portion of the collected PM is re-entrained in the gas stream during rapping. This re-entrained PM is normally collected in subsequent sections of the ESP.

ESP's may be located either upstream of the air heater (hot-side ESP) or downstream of the air heater (cold-side ESP). The location is selected to achieve the best PM resistivity<sup>1</sup> conditions. Most modern

<sup>1</sup> Gas composition, temperature, and particle composition all influence resistivity, which is a measure of the ability of a particle to retain an electrostatic charge. The ability to collect particles using electrostatic

ESPs are cold-side ESPs. Factors affecting the PM collection efficiency of an ESP include flue gas flow rate through the ESP, total plate area, PM resistivity, voltage, and the sectionalization of the ESP. The smaller the collection area of the ESP, the narrower the acceptable resistivity range becomes. To optimize particulate resistivity and maximize collection efficiency, many ESPs utilize a sulfur trioxide (SO<sub>3</sub>) injection system to condition the ash and reduce particulate resistivity. In addition, modern ESP controls allow the ESP operation to be optimized to maximize PM control through overall ESP performance management, power optimization, and programmed cleaning cycles. Finally, good sectionalization of the ESP is important to maximize ESP performance and reliability.

### **5.3.3 Wet Electrostatic Precipitators.**

The principle of operation of a wet ESP is similar to a dry ESP. Particulate matter in the flue gas is exposed to an electric field which induces a charge on the particle which is then drawn to an oppositely charged collection electrode. However, in a wet ESP, the flue gas is cooled below the dew point and consequently particulate matter may be present as either solid or liquid particles. A recent application of wet ESPs is downstream of a wet FGD for the control of sulfuric acid mist on large, utility scale boilers firing high sulfur eastern coals. In this application, the flue gas temperature is below the sulfuric acid and water saturation temperatures as it passes through the wet ESP. As such, water droplets and other condensable materials in the flue gas, including sulfuric acid, are charged and collected by the ESP plates. Filterable PM not entrained from the FGD system may also be collected in the wet ESP. The collection electrodes are either continuously or periodically flushed with water to remove collected materials.

Although wet ESPs can be effective for removing sulfuric acid mist downstream of a wet FGD when firing high sulfur coals, wet ESPs have not been used for natural gas-fired boilers.

### **5.3.4 Wet Scrubbers.**

Wet scrubbers are used in many industrial processes to control PM emissions. Wet scrubbers reduce PM emissions through several mechanisms, including condensation, inertial impaction of PM with water droplets, and reactions of PM and PM precursors with the scrubber reagent.

### **5.3.5 Mechanical Collectors.**

Mechanical collectors are not as effective as a FFB or ESP for particulate matter control. Therefore, while mechanical collectors are a technically feasible BACT alternative, the performance of mechanical collectors is inferior to FFBs and ESPs.

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attraction is directly related to particle resistivity. If the particle resistivity is outside the design range, particle collection efficiency is reduced.

### **5.4 STEP 3. Rank the Technically Feasible Technologies.**

All of the identified PM control technologies, including fabric filter baghouses, dry ESPs, wet ESPs, wet scrubbers, and mechanical collectors are technically feasible technologies for natural gas-fired boilers. However, none of these technologies have been required as BACT for new or modified natural gas-fired boilers. This is because natural gas has almost no inert materials or ash, so that the “uncontrolled” PM and PM<sub>10</sub> emissions from the combustion of these fuels is as low as the controlled PM emission rate from solid fuel combustion using state-of-the-art air pollution control systems like fabric filter baghouses. As a result, for natural gas combustion, none of the control technologies are expected to achieve emission rates lower than the use of natural gas fuel and good combustion practices designed to minimize products of incomplete combustion. The natural gas emission rate is expected to be 0.0076 lb/mmBtu for both PM and PM<sub>10</sub> emissions.

### **5.5 STEP 4. Evaluate the Most Effective Controls.**

The combustion of only natural gas is expected to achieve an emission rate of 0.0076 lb/mmBtu for both PM and PM<sub>10</sub>. This is the highest ranked level of control.

### **5.6 STEP 5. Proposed Particulate Matter BACT Determination.**

Based on this analysis, We Energies has concluded that the use of package boilers firing only natural gas is the best available control technology (BACT) for the control of PM and PM<sub>10</sub> emissions from the natural gas-fired boilers B02 and B03. Based on this analysis, We Energies proposes the following limits as BACT for the control of PM and PM<sub>10</sub> emissions from these boilers.

- (1) Particulate matter and PM<sub>10</sub> emissions from the natural gas-fired boilers B02 and B03 shall be controlled using Ultra Low NO<sub>x</sub> Burners, Overfire Air, and Flue Gas Recirculation as the best available control technology.
- (2) Particulate matter and PM<sub>10</sub> emissions may not exceed 0.0076 pounds per million Btu of heat input.
- (3) Compliance with this emission limit shall be based upon the measurement of particulate matter emissions in accordance with U.S. EPA Reference Method 5, 5B, or 17, and U.S. EPA Other Method 28, or another method approved in writing by the department.
- (4) The total heat input to boilers B02 and B03 combined may not exceed 2,170,000 mmBtu in any consecutive 12-month period.

## Chapter 6. PM<sub>2.5</sub> Control Technology Review.

Particulate matter emissions that are less than 2.5 micrometers in diameter are known as "fine" particles, and are referred to as PM<sub>2.5</sub>. Various pollutants contribute to ambient PM<sub>2.5</sub> concentrations. Fuel combustion, including natural gas, result in direct emissions of PM<sub>2.5</sub>. In addition, PM<sub>2.5</sub> "precursors" can also result in the formation of PM<sub>2.5</sub> in the atmosphere. The U.S. EPA has identified SO<sub>2</sub>, NO<sub>x</sub>, volatile organic compounds (VOCs), and ammonia (NH<sub>3</sub>) as PM<sub>2.5</sub> precursors. These gas-phase precursors undergo chemical reactions in the atmosphere to form secondary PM<sub>2.5</sub>. Direct emissions of PM<sub>2.5</sub> from combustion includes solid or filterable PM<sub>2.5</sub>, and condensable or back half PM<sub>2.5</sub>.

Under the recently promulgated rules to revise the New Source Review (NSR) program in 40 CFR Part 52 to include PM<sub>2.5</sub>, the EPA identified the following PM<sub>2.5</sub> pollutants, and their significant levels:

1. 10 ton per year of direct PM<sub>2.5</sub> emissions
2. 40 ton per year of SO<sub>2</sub> emissions
3. 40 ton per year of NO<sub>x</sub> emissions unless demonstrated not to be a PM<sub>2.5</sub> precursor.

Based on the final rules, VOC and ammonia may not be considered to be precursors to PM<sub>2.5</sub> unless the state demonstrates that these emissions are a significant contributor to the area PM<sub>2.5</sub> concentrations. In addition, during the PM<sub>2.5</sub> SIP development period, the EPA has indicated that NO<sub>x</sub> emissions will not be regulated as a PM<sub>2.5</sub> precursor to give States the opportunity to determine whether NO<sub>x</sub> emissions are a significant contributor to the ambient PM<sub>2.5</sub> concentration<sup>2</sup>.

### 6.1 BACT Baseline.

There are no state implementation plan emission limits or new source performance standards for direct PM<sub>2.5</sub> emissions from these natural gas-fired boilers.

Direct PM<sub>2.5</sub> emissions from the combustion of natural gas include filterable PM<sub>2.5</sub>, and condensable PM<sub>2.5</sub>. The U.S. EPA's *Compilation of Air Pollutant Emission Factors*, AP-42, 5th Edition, Table 1.4-2 includes emission factors for filterable and condensable PM emissions. The total filterable plus condensable emission factor is 7.6 lb/10<sup>6</sup> scf natural gas, equal to 0.0076 lb/mmBtu. For this analysis, all PM emissions from natural gas combustion are also expected to be PM<sub>2.5</sub>.

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<sup>2</sup> Federal Register / Vol. 73, No. 96 / Friday, May 16, 2008, page 28343.

## **6.2 STEP 1. Identify All Potential Control Technologies.**

### **6.2.1 Direct PM<sub>2.5</sub> Emissions.**

As noted in the PM and PM<sub>10</sub> control technology review, the technologies selected as BACT include primarily fabric filter baghouses and electrostatic precipitators. Other controls include mechanical collectors such as multicyclones, and wet venturi scrubbers.

### **6.2.2 PM<sub>2.5</sub> Precursors.**

As noted above, the U.S. EPA has identified SO<sub>2</sub>, NO<sub>x</sub>, VOCs, and ammonia (NH<sub>3</sub>) as PM<sub>2.5</sub> precursors. Based on the final rules, volatile organic compounds (VOC) and ammonia (NH<sub>3</sub>) may not be considered to be precursors to PM<sub>2.5</sub> unless the State demonstrates that these emissions are a significant contributor to the area PM<sub>2.5</sub> concentrations. This control technology review includes a complete control technology review for SO<sub>2</sub>, NO<sub>x</sub>, and VOC emissions. Therefore, further analysis of these pollutants as PM<sub>2.5</sub> precursors is unnecessary.

## **6.3 STEP 2. Identify Technically Feasible Control Technologies.**

As noted above, data from the U.S. EPA's RBLC indicate that the technologies selected as BACT include primarily fabric filter baghouses and electrostatic precipitators. Other controls include mechanical collectors such as multicyclones, and wet venturi scrubbers.

### **6.3.1 Fabric Filter Baghouses.**

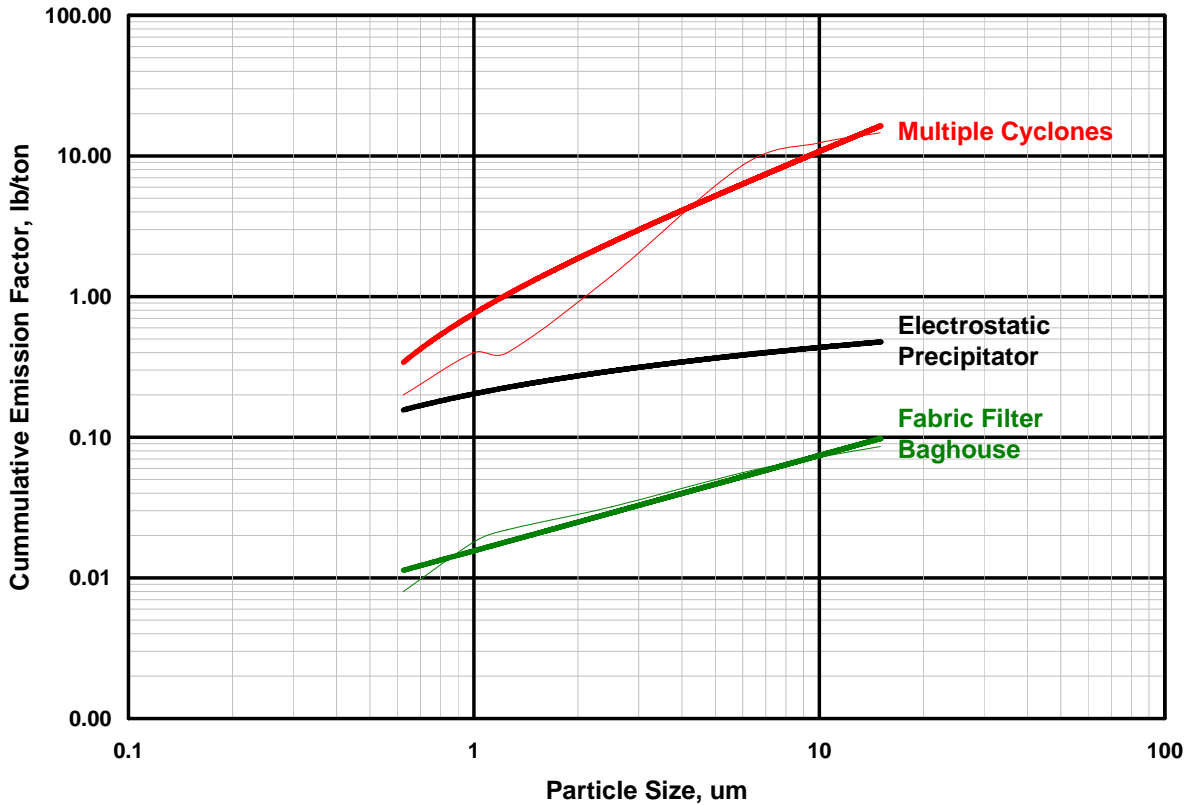
Fabric filter baghouse (FFB) were discussed in the PM/PM<sub>10</sub> control technology review. Fabric filter baghouses are very effective at reducing PM emissions, especially in the fine particle size ranges. Figure 6-1 shows the cumulative emission factor for PM emissions versus the particle size for several different PM control systems for coal combustion<sup>3</sup>. Figure 6-1 shows that fabric filter baghouses are very effective in reducing PM emissions, especially fine PM.

As noted in the PM/PM<sub>10</sub> analysis, the primary filtering media in a fabric filter baghouse is actually the filter cake rather than the fabric itself. The filter cake acts much like a fixed-bed reactor, contributing to greater absorption of pollutants, including fine particulate matter, sulfur dioxide (SO<sub>2</sub>), sulfuric acid mist, mercury and hazardous air pollutants including hydrogen chloride (HCl) and hydrogen fluoride (HF). Since pollutants such as sulfuric acid mist, HCl, and HF directly contribute to condensable PM, fabric filter baghouses are also very effective at reducing the condensable portion of PM<sub>2.5</sub> emissions by controlling these PM<sub>2.5</sub> precursors in the baghouse. However, because natural gas has only trace levels of sulfur, chlorine, and fluorine, these condensable PM removal mechanisms are of limited importance to natural gas combustion.

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<sup>3</sup> Data is from the Air Pollution Engineering Manual, Air & Waste Management Association, coal combustion sources with various air pollution control systems.

**FIGURE 6-1. Cumulative emission factor for PM emissions versus the particle size.**



### 6.3.1.1 Filter Media for Fabric Filter Baghouses and PM<sub>2.5</sub> Control.

There is a wide variety of fabric filter material available for fabric filter baghouses. For reverse air baghouses, the most common fabric is a simple woven fabric such as woven fiberglass. For pulse jet baghouses, the most common fabric is a woven fabric backing called a “scrim” with a felted layer needle punched into the scrim. Other fabric materials include Nomex®, Ryton®, Gortex®, and Hyglass®.

Developments have been made in fabric filter media to improve PM<sub>2.5</sub> control. Advanced filter media provide enhanced PM<sub>2.5</sub> emissions control. The U.S. EPA implemented the Environmental Technology Verification (ETV) program in 1995 to generate independent data on the performance of innovative pollution control technologies. The ETV program identified baghouse filtration products as a high priority technology group in 2000. As stated in a report<sup>4</sup>, “New fabrics have been developed that offer the combination of highly effective particulate removal and low operational pressure drop. Improving performance of the fabrics can be observed in verification test data trends.” Completed verifications of baghouse filtration products are available from the U.S. EPA’s ETV program at

<sup>4</sup> **The Evolution of Improved Baghouse Filter Media as Observed in the Environmental Technology Verification Program**, Andrew Trenholm, RTI International, John Mycock, ETS Inc., John McKenna, ETS Inc., and Michael Kosusko, U.S. EPA, Presented at the Air & Waste Management Association Annual Conference, June, 2008, available at: <http://epa.gov/etv/pubs/600etv08023.pdf>.

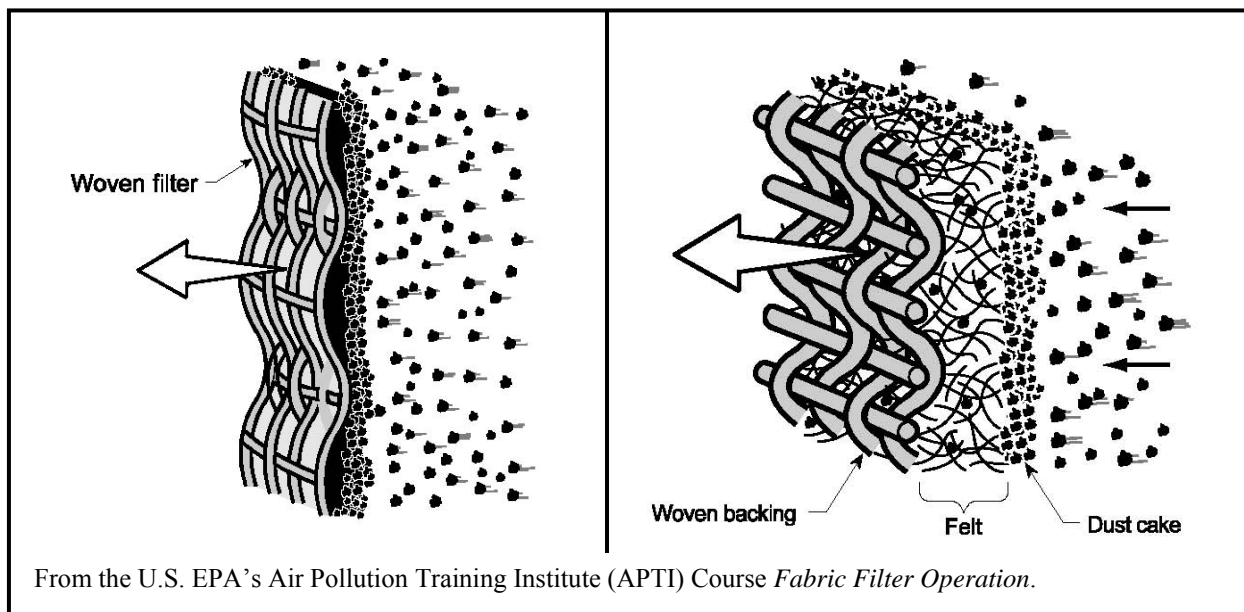
<http://www.epa.gov/nrmrl/std/etv/vt-apc.html>. ETV test results indicate filter media with direct PM<sub>2.5</sub> emission levels as low as 0.000007 gr/dscf, equal to approximately 0.0001 lb/mmBtu. Note, however, that this is the tested performance for the filter media, not for the entire baghouse system. Leaks which occur in even the best state-of-the-art baghouse will increase the outlet grain loading, even when using advanced filter media.

Baghouse filtration product enhancements include felted bags and high efficiency microfiber felts, intrinsically coated (IC) bags, membrane bags, and electrostatic fabric filter technology.

**Felted bags** are often used in pulse-jet fabric filter baghouses which use higher energy cleaning systems than in a reverse air baghouse. Felted filters don't require the initial filter cake to collect fine particulates as compared to woven filters. Felted filters are generally 2 to 3 times thicker than woven filters. This thicker overall filter improves fine particle collection, since each individual randomly oriented fiber acts as a target for particle capture by impaction and interception. Small particles are collected on the outer surface of the filter, rather than depending on the filter cake to achieve fine particle control. Figure 6-2 is a depiction of the fabric filter media filtration process for a simple woven fabric as compared to a felted fabric media.

**High efficiency microfiber felts** are based on the same concept as felted filter media, but use ultra-fine fibers to enhance fine particulate matter control. The U.S. EPA's ETV program tested outlet PM<sub>2.5</sub> levels as low as 0.0004 gr/dscf (0.00055 lb/mmBtu).

**FIGURE 6-2. Depiction of the fabric filter media filtration process for a simple woven fabric as compared to a felted fabric media.**



**Intrinsically coated bags** use a fabric made of coated fibers. The coating is typically Teflon® or a similar fluoro-polymer material. Intrinsically coated bags improve bag durability and also reduce the pore size between fibers, improving direct PM<sub>2.5</sub> control. However, this coating also inhibits filter cake formation. While this can help reduce the pressure drop across the baghouse, the reduced filter cake accumulation may reduce the control effectiveness of the fabric filter baghouse for PM<sub>2.5</sub> precursors and condensable PM<sub>2.5</sub> species by limiting the contact between these precursors and solids in the filter cake which would otherwise remove these precursors.

**Membrane bags** have a polytetrafluoroethylene (PTFE) coating such as Teflon® applied to the surface of the fabric rather than to the individual fibers. Membrane bags have even smaller pore sizes than intrinsically coated bags. This smaller pore size may further improve direct PM<sub>2.5</sub> control. However, the coating over the entire bag further inhibits filter cake formation and may further reduce the control effectiveness of the fabric filter baghouse for PM<sub>2.5</sub> precursors and condensable PM<sub>2.5</sub> species by limiting the contact between these precursors and solids in the filter cake.

**High efficiency microfiber felts** are based on the same concept as felted filter media, but use ultra-fine fibers to enhance fine particulate matter control. The U.S. EPA's ETV program tested outlet PM<sub>2.5</sub> levels as low as 0.0004 gr/dscf (0.00055 lb/mmBtu).

**Electrostatic fabric filter baghouses** have been developed through a partnership of the U.S. EPA and Southern Research Institute. The technology is licensed to General Electric Energy (GE) and is marketed as the Max-9™ electrostatic fabric filter baghouse. The Max-9™ is a dust collection technology that combines discharge electrodes and fabric filters in the same casing to provide high collection efficiency while operating at a 60 to 80% lower system pressure drop. The Max-9 ESFF is an electrostatic precipitator/pulse-jet baghouse hybrid, employing high voltage discharge electrodes to charge particulate, but with fabric filters instead of collecting plates in the casing. GE Power states that “The Max-9 ESFF provides collection efficiencies an order of magnitude higher than those achieved by either the best fabric filters or precipitators currently on the market, with demonstrated efficiency of 99.999%.”<sup>5</sup>

GE states that the ESFFB technology is recommended for use in conjunction with a primary particulate control device; i.e., the Max-9 is recommended as a “polishing” control device for PM emissions. The U.S. EPA and the Southern Research Institute conducted pilot testing of a slip stream at a major power plant in the Southern United States. The pilot plant was configured to allow testing with or without discharge electrode energization. With the electrostatic stimulation turned on, collection efficiency increased from 99.99% to 99.999%, a full order of magnitude better. Plus, there was an 80% reduction in pressure drop, and an 80-90% reduction in sub-micron particle emissions.

While the Max-9 ESFFB technology shows great promise, this technology has not been demonstrated on a full scale facility. Therefore, this technology is not technically feasible for these natural gas-fired boilers.

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<sup>5</sup> As stated at: [http://www.gepower.com/prod\\_serv/products/particulate\\_matter/en/max9/index.htm](http://www.gepower.com/prod_serv/products/particulate_matter/en/max9/index.htm).

### **6.3.2 Dry Electrostatic Precipitators.**

Electrostatic precipitators (ESP) are a common PM control system for both coal and biomass-fired boilers, and are discussed in the PM/PM<sub>10</sub> control technology review. While dry ESPs are a technically feasible control technology, a dry ESP is expected to have significantly lower control efficiencies for both direct filterable PM<sub>2.5</sub> emissions, and also for PM<sub>2.5</sub> precursors.

### **6.3.3 Wet Electrostatic Precipitators.**

The principle of operation of a wet ESP is similar to a dry ESP. Wet ESPs can be effective for removing sulfuric acid mist downstream of a wet FGD when firing high sulfur coals. However, we are not aware of the use of a wet ESPs as a PM control system for natural gas-fired boilers. Wet ESPs experience current suppression when PM concentrations in the electrode wash water are too high which would reduce or eliminates the PM control effectiveness of the wet ESP. Therefore, a wet ESP must be considered as a secondary or “polishing” PM control device.

While wet ESPs cannot operate as the primary control device, wet ESPs have shown promise at reducing PM<sub>2.5</sub> emissions as a polishing device. A pilot wet ESP was installed at First Energy’s Bruce Mansfield Plant in Shippingport, PA. The pilot wet ESP uses a slipstream of flue gas from the outlet of an FGD system on an 835 MW unit firing 3% sulfur coal. The plant installed the pilot WESP to test for PM<sub>2.5</sub> and SO<sub>3</sub> mist removal as a potential control technology to reduce visible emissions. The slipstream results indicate reductions in PM<sub>2.5</sub> emissions from 62% to 96%. These results also showed similar high SO<sub>3</sub> mist removal, which may account for much of the PM<sub>2.5</sub> emission reductions. However, these tests were a slipstream test, not a fullscale test, and were for a limited duration.

### **6.3.4 Wet Scrubbers.**

Wet scrubbers are used in many industrial processes to control PM emissions. Wet scrubbers reduce PM emissions through several mechanisms, including condensation, inertial impaction of PM with water droplets, and reactions of PM and PM precursors with the scrubber reagent.

### **6.3.5 Mechanical Collectors.**

Mechanical collectors are not as effective as a FFB or ESP for PM control, especially for fine PM control. Therefore, while mechanical collectors are a technically feasible BACT alternative, the performance of mechanical collectors is inferior to FFBs and ESPs.

## **6.4 STEP 3. Rank the Technically Feasible Technologies.**

Direct PM<sub>2.5</sub> emissions from the combustion of natural gas is expected to be very small, equal to 0.0076 lb/mmBtu. In addition, fabric filter baghouses, dry ESPs, wet ESPs, wet scrubbers, and mechanical collectors are technically feasible technologies. However, we are not aware of the use of any post combustion PM control systems on any natural gas-fired boiler. Further, because of the very low expected PM<sub>2.5</sub> emission rates from the combustion of natural gas, there is no basis to conclude that post

combustion PM controls would actually result in reductions in PM<sub>2.5</sub> emissions. Therefore, the highest ranked or most effective PM<sub>2.5</sub> control technology for these natural gas-fired boilers is the use of natural gas as the fuel.

## **6.5 STEP 4. Evaluate the Most Effective Controls.**

Based on the ranking summarized in Table 6-1, the use of natural gas fuel and good combustion practices designed to minimize products of incomplete combustion is expected to achieve a PM<sub>2.5</sub> emission rate of 0.0076 lb/mmBtu. The use of additional add on controls will not reduce emissions below these levels.

## **6.6 STEP 5. Proposed PM<sub>2.5</sub> BACT Determination.**

Based on this analysis, We Energies has concluded that the use of package boilers firing only natural gas is the best available control technology (BACT) for the control of PM<sub>2.5</sub> emissions from the natural gas-fired boilers B02 and B03. Based on this analysis, We Energies proposes the following limits as BACT for the control of PM and PM<sub>10</sub> emissions from these boilers.

- (1) PM<sub>2.5</sub> emissions from the natural gas-fired boilers B02 and B03 shall be controlled using Ultra Low NO<sub>x</sub> Burners, Overfire Air, and Flue Gas Recirculation as the best available control technology.
- (2) PM<sub>2.5</sub> emissions may not exceed 0.0076 pounds per million Btu of heat input.
- (3) The total heat input to boilers B02 and B03 combined may not exceed 2,170,000 mmBtu in any consecutive 12-month period.



# Chapter 7. Sulfur Dioxide (SO<sub>2</sub>) Control Technology Review.

Sulfur dioxide (SO<sub>2</sub>) emissions from natural gas-fired boilers result from the oxidation of sulfur in the fuel. During combustion, the majority of the sulfur is emitted as SO<sub>2</sub>. A small portion of the sulfur is further oxidized to sulfur trioxide (SO<sub>3</sub>). When the flue gas temperature drops below the dew point temperature, sulfur trioxide is converted to sulfuric acid (H<sub>2</sub>SO<sub>4</sub>). Therefore, control technologies which control SO<sub>2</sub> emissions also reduce sulfuric acid mist emissions to varying degrees.

## 7.1 BACT Baseline.

The proposed natural gas-fired boilers would be subject to the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units under 40 CFR Part 60, Subpart Db. This subpart applies to units that commence construction, modification, or reconstruction after June 19, 1984, and have a heat input from fuels combusted in the steam generating unit greater than 100 mmBtu/hr. The SO<sub>2</sub> standards in Subpart Db are only applicable when distillate fuel oil is fired. Under 40 CFR 60.41b and NR 440.205(2)(zj), "very low sulfur oil" is defined as:

(zj) "Very low sulfur oil" means an oil that contains no more than 0.50 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 215 ng/J (0.50 lb/million Btu) heat input.

For facilities combusting only very low sulfur oil, SO<sub>2</sub> emissions are limited to 0.50 lb/mmBtu. According to 40 CFR 60.42b(j) and NR 440.205(3)(j), affected sources combusting only very low sulfur oil are not subject to the SO<sub>2</sub> percent reduction requirements. According to 40 CFR 60.42b(j) and NR 440.205(6)(j) and NR 440.205(8)(f), facilities that combust very low sulfur oil are not required to conduct performance testing or install and operate continuous monitors for SO<sub>2</sub> if fuel receipts are maintained.

Because these boilers will fire only natural gas, there are no applicable NSPS SO<sub>2</sub> standards.

## 7.2 STEP 1. Identify Potential Control Technologies.

Potential SO<sub>2</sub> control technologies include pre-combustion controls such as low sulfur fuels, and post combustion controls, such as flue gas desulfurization. Table 7-1 summarizes the SO<sub>2</sub> BACT emission limits for new and modified natural gas-fired boilers in the U.S. EPA's RACT/BACT/LAER Clearinghouse. The only technologies identified include the use of clean fuels. Emission limits range from 0.0006 to 0.006 lb/mmBtu for natural gas combustion. Please note that many of the emission limits in these tables were expressed as pounds per hour. These rates were converted to lb/mmBtu to make the emission limits comparable.

**TABLE 7-1. Natural gas-fired boiler SO<sub>2</sub> emission limits representing BACT from the U.S. EPA's RBLC database.**

<b>RBLC ID</b>	<b>Facility</b>	<b>Permit Date</b>	<b>Process</b>	<b>Thruput, mmBtu/hr</b>	<b>Controls</b>	<b>Limit, lb/mmBtu</b>
*AL-0230	Thyssenkrupp Steel & Stainless USA	08/17/07	3 Boilers	65		0.0006
OH-0310	American Municipal Power Generating Station	02/07/08	Auxiliary Boiler	150		0.0006
WI-0228	Wisconsin Public Service - Weston Plant	10/19/04	Auxiliary Boiler	230	Natural Gas	0.0006
OK-0045	Redbud Power Plant	08/15/01	Auxiliary Boiler	20	Pipeline Natural Gas	0.0006
AR-0026	Pine Bluff Energy LLC-Pine Bluff Energy Center	05/05/99	Boiler, Natural Gas	362	Low Sulfur Fuels	0.0006
TX-0499	Sandy Creek Energy Station	07/24/06	Auxiliary Boiler	175		0.0006
NJ-0042	Roche Vitamins	02/05/99	Boiler 3 (Nat Gas)	152	None Listed	0.00066
VA-0278	Virginia Commonwealth University East Plant	03/31/03	Boiler	151	Low Sulfur Fuel	0.00066
VA-0270	Virginia Commonwealth University East Plant	03/31/03	Boiler	150	Low Sulfur Fuel	0.00067
NJ-0042	Roche Vitamins	02/05/99	Boiler	134	None Listed	0.00075
NJ-0042	Roche Vitamins	02/05/99	Boiler	118	None Listed	0.00085
NJ-0042	Roche Vitamins	02/05/99	Boiler	84	None Listed	0.0012
MN-0039	Minnesota Corn Processors	08/08/00	Boiler	237	Natural Gas	0.0017
NJ-0043	Liberty Generating Station	03/28/02	Auxiliary Boiler	200	None	0.0040
NJ-0036	AES Red Oak LLC	10/24/01	Auxiliary Boiler	120	Natural Gas Fuel	0.0043
TX-0386	Calpine Amella Energy Center	03/26/02	Auxiliary Boiler	155		0.0054
NC-0101	Forsyth Energy Plant	09/29/05	Auxiliary Boiler	110	Natural Gas	0.0055
IN-0085	PSEG Lawrenceburg Energy Facility	06/07/01	Auxiliary Boiler	125	Natural Gas	0.006
AR-0057	Tenaska Arkansas Partners, LP	10/09/01	Boiler	122	Natural Gas.	0.006
CA-1024	AES Huntington Beach	08/01/02	Boiler:	225	Sulfur In Fuel	0.2
OH-0241	Miller Brewing Company - Trenton	05/27/04	Boiler	238		1.6

**Footnotes**

“GCP” means good combustion practices. “SCR” means selective catalytic reduction. “LNB” means low NOx burner. “ULNB” means ultra-low NOx burner. “FGR” means flue gas recirculation.

## 7.3 STEP 2. Identify Technically Feasible Control Technologies.

As noted above, the only technologies identified as BACT in the U.S. EPA's RACT/BACT/LAER Clearinghouse for new natural gas-fired boilers include the use of low sulfur fuels including natural gas. However, post combustion controls including flue gas desulfurization (FGD) are technically feasible control options. However, while these technologies may be technically feasible, because the fuel sulfur levels are so low in natural gas, FGD systems are not expected to reduce potential SO<sub>2</sub> emissions significantly below the uncontrolled levels from the combustion of natural gas.

### 7.3.1 Low Sulfur Fuels and Fuel Cleaning.

Sulfur dioxide emissions may be controlled by the use of post-combustion FGD systems designed to remove SO<sub>2</sub> from the flue gas after combustion. Because SO<sub>2</sub> emissions occur from the oxidation of fuel sulfur, SO<sub>2</sub> emissions may also be controlled by limiting the fuel sulfur content. As noted above, the only technologies identified as BACT in the U.S. EPA's RACT/BACT/LAER Clearinghouse for new natural gas and distillate fuel oil-fired boilers include the use of these low sulfur fuels.

Under the Acid Rain Program in 40 CFR 72.2, *pipeline natural gas* means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot. Based on these values, the uncontrolled SO<sub>2</sub> emission rate of pipeline natural gas is:

$$ER_{NG} = \left[ \frac{0.5 \text{ grains S}}{100 \text{ scf NG}} \right] \left[ \frac{1.0 \text{ lb S}}{7,000 \text{ grains S}} \right] \left[ \frac{2.0 \text{ lb SO}_2}{1.0 \text{ lb S}} \right] \left[ \frac{1.0 \text{ scf NG}}{950 \text{ Btu}} \right] \left[ \frac{1,000,000 \text{ Btu}}{1.0 \text{ mmBtu}} \right]$$
$$ER_{NG} = 0.0015 \text{ lb SO}_2/\text{mmBtu}$$

An emission rate of 0.0015 lb/mmBtu is equal to an SO<sub>2</sub> concentration in the flue gas of 0.8 parts per million (ppm) at 5% excess oxygen.

The emission factor for uncontrolled SO<sub>2</sub> emissions from the U.S. EPA's *AP-42, Compilation of Air Pollutant Emission Factors*, 5th Edition, section 1.4, Natural Gas Combustion, is 0.6 pounds per million cubic feet of natural gas. At a natural gas heat value of 1,000 Btu/scf, this emission factor is equal to 0.0006 lb/mmBtu.

### 7.3.2 Flue Gas Desulfurization.

Flue Gas Desulfurization (FGD) technologies are primarily used for large utility and industrial coal-fired boilers. FGD systems may be broadly classified as "wet" and "dry" systems. Wet FGD systems are

characterized by low flue gas outlet temperatures, saturated or wet flue gas conditions, and a wet sludge reaction product which is dewatered before reuse or disposal. For most solid fuels and boiler types, the flue gas saturation temperature is about 130 °F. In wet FGD applications, the primary PM control system is located *upstream* of the wet FGD system so that the fly ash and FGD system reaction products are collected *separately*. This is necessary to avoid saturated conditions in the PM control system which would plug a fabric filter baghouse or dry ESP. Wet FGD systems are also characterized by relatively high water use as compared to dry FGD systems.

Dry FGD systems are characterized by outlet flue gas temperatures about 20 to 50 °F above the saturation point, or about 150 °F to 180 °F. In dry FGD applications, the PM system is located *downstream* of the dry FGD system so that the fly ash and the FGD reaction product are *commingled* into a single stream. Dry FGD systems also have reduced water use as compared to wet FGD systems.

### **7.3.2.1 Wet Flue Gas Desulfurization.**

Wet FGD is a well demonstrated technology for the control of SO<sub>2</sub> emissions from utility scale coal-fired boilers. However, we are not aware of the use of wet FGD systems on any natural gas or distillate fuel oil-fired boilers either in the U.S. or abroad. In a wet FGD system, the flue gas is exposed to an alkaline reagent which reacts with SO<sub>2</sub> to form a solid. There are several alkaline reagents used in wet FGD systems, including water-based slurries of lime or limestone, liquors containing dissolved sodium or magnesium salts, or amine based liquors including ammonia.

Regardless of the wet FGD design, the flue gas leaving the absorber is saturated with water, and the stack will have a visible condensed moisture plume. The conditions downstream of the absorber are highly corrosive, requiring highly corrosion-resistant materials for the downstream ductwork and stack. Equipment is also needed to manage the condensation that occurs on the downstream ductwork and in the stack. The wet FGD reaction products also require dewatering, usually by a combination of hydroclones and vacuum filters. Large areas are needed to manage the dewatering and byproduct storage, as well as the substantial water treatment facilities required for the FGD systems. These factors contribute to the high capital and operating costs of wet FGD systems.

#### **7.3.2.1.1 Advanced Wet FGD Designs.**

The first FGD systems in the U.S. were installed largely in response to the 1971 Clean Air Act. Most of these original FGD systems were calcium based wet FGD systems. About half of these early systems were lime and the other half limestone. Many of these FGD systems were plagued with operational issues including scaling, plugging, and low SO<sub>2</sub> removal. These first wet FGD systems utilized spray tower absorbers, often without a perforated plate tray, as the method for contacting the flue gas with the reagent.

FGD systems installed in the 1990's were 2<sup>nd</sup> and 3<sup>rd</sup> generation systems which generally achieved greater than 90% SO<sub>2</sub> removal with improved reliability. The limestone systems installed during this time were mostly forced oxidation systems which demonstrated the ability to achieve similar performance and reliability as lime systems. The SO<sub>2</sub> removal efficiencies of the 2<sup>nd</sup> and 3<sup>rd</sup> generation systems were

improved primarily by improving gas to liquid contact. These improvements include absorption trays with perforated plates and multiple levels of interspatial reagent spray nozzles.

FGD system suppliers have introduced several new designs to improve the flue gas to FGD liquid reagent contact and minimize operating costs. Designs such as the Jet Bubbling Reactor developed by Chiyoda and Alstom's Flowpac systems were developed to improve the gas-to-liquid contact by forcing the flue gas to bubble through the liquid reagent using a gas sparger design rather than spraying the alkaline slurry into the gas stream. Mitsubishi developed the Double Contact Flow Scrubber (DCFS) which uses 'fountains' of slurry to contact the flue gas. Babcock Power Environmental Inc. utilizes bidirectional sprays and wall rings to maximize contact between the flue gas and liquid reagent. All of these wet FGD systems use the limestone forced oxidation (LSFO) process.

#### **7.3.2.1.2 Wet Limestone with Forced Oxidation.**

In recent years, the WFGD market has turned almost completely to the use of wet lime or limestone with forced oxidation on utility scale coal-fired boilers because it improves SO<sub>2</sub> control, reduces chemical scale formation, and produces gypsum, a stable and potentially saleable byproduct. Wet limestone with forced oxidation (LSFO) is a modification of the conventional wet limestone FGD process. A conventional wet limestone system forms a scrubber product composed mostly of calcium sulfite (CaSO<sub>3</sub>). The LSFO process further oxidizes calcium sulfite to calcium sulfate dihydrate (gypsum, or CaSO<sub>4</sub>·2H<sub>2</sub>O). The gypsum content of the scrubber sludge is typically 95% on a dry basis, making the sludge easier to dewater. Gypsum is a naturally occurring mineral that is used as a raw material in the manufacture of plaster, wallboard, Portland cement, agricultural soil conditioners, and other products.

In the LSFO process, flue gas exits the primary PM pollution control system at approximately 300 °F and enters a spray tower where an alkaline slurry consisting of limestone (calcium carbonate), calcium sulfite, and calcium sulfate is contacted with the flue gas. Through a series of reactions, SO<sub>2</sub> in the flue gas reacts with calcium carbonate to form CaSO<sub>3</sub>. The flue gas exits the absorption tower through a series of chevron mist eliminators to remove entrained moisture droplets. The calcium sulfite remains in the slurry which drains into a recirculation tank located at the bottom of the spray tower. By injecting air into the slurry using fans or blowers, the calcium sulfite is oxidized to CaSO<sub>4</sub>·2H<sub>2</sub>O. A portion of the slurry in the recirculation tank is pumped back into the spray tower, and a portion is removed. The removed slurry is dewatered and stockpiled for transport offsite. The overall FGD reaction is:



The LSFO process can achieve high levels of control on coal-fired boilers. Recent BACT determinations put the level of control at 95 - 97% range. However, the same performance principle for any SO<sub>2</sub> control system is also true for the LSFO – as the boiler outlet SO<sub>2</sub> concentration decreases, the ability to achieve high control efficiencies also decreases.

### 7.3.2.1.3 Technical Feasibility

WFGD is a well demonstrated technology for the control of SO<sub>2</sub> emissions from coal-fired boilers. Wet FGD systems have been installed primarily on large utility scale pulverized coal-fired boilers combusting higher sulfur coals. Other advanced designs from Chiyoda, Alstom, Mitsubishi, and Babcock Power Environmental Inc. are also technically feasible. However, as noted above, the current wet FGD systems are 3<sup>rd</sup> generation FGD systems which would integrate many of the advances in wet FGD design. While a wet FGD system is technically feasible for this natural gas-fired boiler, we are not aware of the use of wet FGD systems on any natural gas-fired boilers either in the U.S. or abroad.

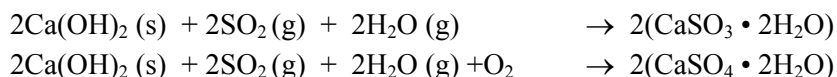
### 7.3.2.2 Dry Flue Gas Desulfurization.

Dry FGD is also a well demonstrated technology for the control of SO<sub>2</sub> emissions from coal-fired electric generating units. Like wet FGD systems, dry FGD systems can be divided into several types. Dry FGD systems involve injecting a dry sorbent into the furnace or flue gas duct; the by-product solids are collected with the boiler fly ash. In semi-dry FGD systems, the sorbent is introduced as an aqueous slurry or a humidified dry powder to improve SO<sub>2</sub> control efficiency. The water content is controlled so that the reaction by-products are dry solids. While the flue gas temperature in both types remains above the adiabatic saturation temperature, the semi-dry systems have lower temperatures and a closer approach to the saturation temperature. The primary PM control system for dry FGD applications is often a fabric filter baghouse since they can provide higher reagent utilization.

Dry FGD systems do not have a saturated plume and therefore do not require the same design elements related to a saturated and corrosive plume as wet FGD systems. Since the dry FGD reaction products are also dry, there is no need for dewatering equipment or wastewater discharge. The reaction product in dry FGD systems is primarily calcium sulfite, with smaller amounts of calcium sulfate. Because of the calcium sulfite content, the dry FGD byproduct will undergo pozzolanic (cementitious) reactions when wetted. This material has limited commercial value and is typically disposed of as waste material.

#### 7.3.2.2.1 Lime Spray Drying Absorber

One of the most widely used dry FGD technologies is the lime spray dry absorber (LSDA). LSDA is a semi-dry FGD technology that is often used on utility scale low sulfur coal-fired boilers. The LSDA process employs a spray dryer absorber (SDA) and a downstream PM control device. The SDA introduces a lime or limestone slurry and flue gas at the top of an absorber vessel. Rotary atomizers or nozzles are used to create a spray of slurry droplets which are dispersed in the flue gas stream. The water in the slurry droplets evaporates as the flue gas passes through the absorber, cooling and humidifying the flue gas stream and rapidly drying the slurry to a powder. In practice, water is added to control the SDA outlet temperature to approximately 155°F, or an approach temperature approximately 25°F above the saturation temperature. SO<sub>2</sub> in the flue gas reacts with calcium hydroxide in the reactor or on the fabric filter bags to form solid calcium sulfite (CaSO<sub>3</sub>) and calcium sulfate (CaSO<sub>4</sub>):



Fly ash, reaction products, and unreacted lime are captured downstream in the PM control system. A portion of the collected material is recycled back to the SDA to improve reagent utilization.

#### **7.3.2.2.2 Advanced Semi-Dry FGD Systems**

Advanced Semi-Dry FGD systems include circulating fluidized bed (CFB) systems, hydrated lime injection systems such as Turbosorp, circulating dry scrubbers (CDS), and flash dry absorbers, also called novel integrated desulphurization system (NIDS). These systems are often utilized in circulating fluidized bed (CFB) boiler applications where excess lime (CaO) produced in the CFB boiler can be used to further reduce SO<sub>2</sub> emissions. The ash captured in the baghouse containing excess lime is hydrated to form calcium hydroxide (Ca(OH)<sub>2</sub>). The ash is then reinjected into the flue gas in a vessel upstream of the PM control device.

These advanced semi-dry systems may be contrasted with conventional SDA systems in that the ash is humidified but remains a free-flowing solid, as opposed to being hydrated to a slurry as in the SDA process. This lower water content eliminates the need for slurry handling, atomization, and a large reactor. Reinjecting a dry solid also allows the reagent to disperse rapidly in the flue gas. These systems may also be contrasted with conventional SDA systems in that the solids recirculation rate is 30 to 100 times, compared to 3 – 5 times in a conventional SDA system. These semi-dry FGD systems have demonstrated the ability to achieve SO<sub>2</sub> emission reductions equivalent to, and in some cases greater than, that achieved by conventional dry FGD systems and LSDA.

#### **7.3.2.2.3 Technical Feasibility.**

Dry FGD systems, including lime spray drying absorbers, circulating fluidized bed systems, hydrated lime injection systems, and flash dryer absorbers, are all demonstrated for the control of SO<sub>2</sub> emissions from coal-fired boilers. While a dry FGD system is technically feasible for the natural gas-fired boilers, we are not aware of the use of dry FGD systems on any natural gas-fired boilers either in the U.S. or abroad.

#### **7.3.2.3 Sorbent Injection.**

Sorbent injection systems may be considered as dry FGD systems in which a powdered sorbent is injected into the furnace or downstream ductwork. Several types of sorbent injection are available, including furnace sorbent injection, and duct sorbent injection.

Duct sorbent injection (DSI) is a dry FGD system. In a typical DSI system, water is injected into the duct downstream of the air preheater to cool and humidify the flue gas. Sorbents such as hydrated quicklime or trona (sodium sesquicarbonate or Na<sub>2</sub>CO<sub>3</sub> • NaHCO<sub>3</sub> • 2H<sub>2</sub>O) are injected into the duct upstream of the PM control system. The fly ash, sorbent reaction products, and unused sorbent are collected in the PM control system. Duct sorbent injection has typical SO<sub>2</sub> removal efficiencies ranging from 40 to 70%.

Furnace sorbent injection is also a dry system. Sorbents such as limestone, hydrated lime or trona is injected into the boiler furnace. The injection point is selected based on the temperature window that is required for the reagent, typically around 1,000 – 1,500°F. Water is injected into the ductwork between

the air heater and the PM collector for flue gas conditioning to promote additional SO<sub>2</sub> removal. The reaction product and fly ash are collected in the PM collection system. In retrofit situations, furnace sorbent injection systems typically achieve SO<sub>2</sub> removal efficiencies of 30-40%.

#### **7.3.2.3.1 Technical Feasibility.**

Sorbent injection is technically feasible for the natural gas-fired boilers,. However, while a sorbent injection system is technically feasible, we are not aware of the use of dry FGD systems on any natural gas-fired boilers either in the U.S. or abroad.

#### **7.3.2.4 Emerging Flue Gas Desulfurization Technologies.**

Emerging SO<sub>2</sub> control technologies include Enviroscrub (also known as the Pahlman process), ECO scrubber, REACT, and the Airborne process. These emerging technologies are not yet demonstrated through installation and successful operation on a full scale utility boiler or are not available or applicable. Of these advanced processes, the ECO system process is closest to commercial operation. The ECO process has been installed as a slip stream unit on a bituminous coal-fired boiler. The ECO system being offered is a redesigned version of the slip stream scrubber taking into account the “lessons learned.” The ECO system design has not yet been installed or demonstrated on a full scale on any boiler.

The REACT technology from Japan consists of three major process steps: absorption, regeneration, and byproduct recovery. The absorption process utilizes pelletized activated coke (ATC) and ammonia for removal of SO<sub>2</sub> and sulfuric acid from the flue gas. The mechanism for the removal of pollutants is very different between the REACT and wet FGD processes, although they are both located in the flue gas stream downstream of the primary PM control system. The absorption and regeneration processes of the REACT technology are dry, and require secondary particulate removal to collect the reaction product.

In October, 2004, the U.S. Department of Energy announced that Peabody Energy’s Mustang Energy project will be awarded a \$19.7 million Clean Coal Power Initiative grant for demonstrating technology to achieve ultra-low emissions at a proposed 300 MW facility near Grants, New Mexico. The Mustang Clean Coal Project is intended to demonstrate Airborne’s emission control process. The technology would combine a dry sodium bicarbonate injection with enhanced wet sodium bicarbonate scrubbing. Because the sodium bicarbonate reagent is expensive and the reaction product has limited value, the Airborne Process™ regenerates the scrubber reagent. The regeneration process would recover the reagent for reuse and convert SO<sub>2</sub> and NO<sub>x</sub> into ammonium sulfate and ammonium nitrate based fertilizers.

#### **7.3.2.4.1 Technical Feasibility.**

While several advanced FGD technologies show promise in achieving very low SO<sub>2</sub> emission rates, these processes are not commercial, nor are they demonstrated in practice. With respect to the Airborne project, because the Mustang project is receiving U.S. DOE funding to demonstrate the technology’s feasibility, it is, by definition, *not* demonstrated in practice. With respect to other advanced technologies, due to the lack of demonstrated performance of these emerging technologies, these technologies are not considered technically feasible SO<sub>2</sub> control options for these boilers.

### **7.4 STEP 3. Rank the Technically Feasible Technologies.**

Design SO<sub>2</sub> control efficiencies for advanced wet FGD systems are as high as 98% to 99%, down to SO<sub>2</sub> outlet concentrations of approximately 9 ppm or 0.02 lb/mmBtu. Design SO<sub>2</sub> control efficiencies for advanced dry FGD systems are as high as 95% to 98%, down to SO<sub>2</sub> outlet concentrations of approximately 15 ppm or 0.032 lb/mmBtu. However, neither wet nor dry FGD systems are expected to routinely achieve these very low concentrations. The uncontrolled SO<sub>2</sub> emission rates for natural gas is 0.0006 lb/mmBtu. While flue gas desulfurization systems are technically feasible, these controls are not expected to achieve SO<sub>2</sub> emission rates significantly below the uncontrolled SO<sub>2</sub> emission rates for natural gas combustion of approximately 0.4 parts per million at 5% excess O<sub>2</sub>. Therefore, the use of wet FGD and dry FGD in combination with the use of natural gas are expected to achieve the same outlet SO<sub>2</sub> emission rate as the use of natural gas only.

### **7.5 STEP 4. Evaluate the Most Effective Controls.**

The most effective SO<sub>2</sub> control option for these natural gas-fired boilers is the use low sulfur containing fuels including natural gas. Based on the use of these fuels, potential SO<sub>2</sub> emissions would be limited to less than 0.3 tons per year.

### **7.6 STEP 5. Proposed Sulfur Dioxide BACT Determination.**

Based on this analysis, We Energies has concluded that the use of package boilers firing only natural gas is the best available control technology (BACT) for the control of SO<sub>2</sub> emissions from the natural gas-fired boilers B02 and B03. Based on this analysis, We Energies proposes the following limits as BACT for the control of PM and PM<sub>10</sub> emissions from these boilers.

- (1) Sulfur dioxide (SO<sub>2</sub>) emissions from the natural gas-fired Boilers B02 and B03 shall be controlled using low sulfur fuels including natural gas as the best available control technology.
- (2) Sulfur dioxide (SO<sub>2</sub>) emissions may not exceed 0.0006 pounds per million Btu of heat input.
- (3) The total heat input to boilers B02 and B03 combined may not exceed 2,170,000 mmBtu in any consecutive 12-month period.



# Chapter 8. Volatile Organic Compound (VOC) Control Technology Review.

As with CO emissions, volatile organic compounds (VOC) are emitted from natural gas-fired boilers as a result of incomplete combustion. Incomplete combustion can also result in emissions of particulate matter, CO, and organic hazardous air pollutants, and it reduces boiler efficiency. Because fuel costs represent the highest single operating cost for these boilers, large industrial boilers are designed to achieve the highest combustion efficiencies practicable. VOC emissions can be reduced by operating the boiler with higher flame temperatures, higher excess oxygen levels, and longer furnace residence times. Unfortunately, techniques for reducing VOC emissions can increase NO<sub>x</sub> emissions. Consequently, as with CO emissions, achieving low VOC and NO<sub>x</sub> emission rates is a balancing act in the boiler design and operation.

## 8.1 BACT Baseline.

There are no specific state implementation plan (SIP) requirements or new source performance standards for VOC emissions from natural gas-fired boilers.

## 8.2 STEP 1. Identify All Available Control Technologies.

Table 8-1 summarizes the VOC BACT emission limits for new and modified natural gas-fired boilers in the U.S. EPA's RACT/BACT/LAER Clearinghouse. The technologies identified include the use of clean fuels including natural gas and distillate fuel oil, the use of good combustion practices, and the use of oxidation catalysts. Emission limits range from 0.0013 to 0.0479 lb/mmBtu of heat input for natural gas combustion. Please note that many of the emission limits in these tables were expressed as pounds per hour. These rates were converted to pounds per million Btu based on the rated heat input for the boiler to make the emission limits comparable.

**TABLE 8-1. Natural gas-fired boiler VOC emission limits representing BACT from the U.S. EPA's RBLC database.**

<b>RBLC ID</b>	<b>Facility</b>	<b>Permit Date</b>	<b>Process</b>	<b>Thruput, mmBtu/Hr</b>	<b>Controls</b>	<b>Limit, lb/mmBtu</b>
NJ-0042	Roche Vitamins	02/05/99	Boiler	152	None Listed	0.0013
NJ-0042	Roche Vitamins	02/05/99	Boiler	134	None Listed	0.0015
NJ-0042	Roche Vitamins	02/05/99	Boiler	118	None Listed	0.0017
AR-0026	Pine Bluff Energy LLC-Pine Bluff Energy Center	05/05/99	Boiler	362	GCP	0.0020
NJ-0042	Roche Vitamins	02/05/99	Boiler	84	None Listed	0.0024
TX-0499	Sandy Creek Energy Station	07/24/06	Auxiliary Boiler	175		0.0040
NJ-0036	AES Red Oak LLC	10/24/01	Auxiliary Boiler	120	GCP	0.0040
AR-0057	Tenaska Arkansas Partners, LP	10/09/01	Boiler (2)	122	GCP	0.0040
OR-0046	Calpine Turner Energy Center, LLC	01/06/05	Auxiliary Boiler	417904	OC	0.0044
MN-0066	Northern States Power Co. - Riverside Plant	05/16/06	Auxiliary Boiler	160	GCP	0.0050
OK-0045	Redbud Power Plant	08/15/01	Auxiliary Boiler	20	GCP	0.0050
AL-0128	Alabama Power Co. - Theodore Cogeneration	03/16/99	Boiler	220	Efficient Combustion	0.0050
*GA-0127	Southern Company Plant Mc Donough	01/07/08	Auxiliary Boilers	200		0.0051
NC-0101	Forsyth Energy Plant	09/29/05	Auxiliary Boiler	110	LNB, GCP	0.0054
WI-0228	Wisconsin Public Service - Weston Plant	10/19/04	Auxiliary Boiler	230	LNB, GCP	0.0054
WV-0023	Longview Power, LLC	03/02/04	Auxiliary Boiler	225	GCP	0.0054
IN-0085	PSEG Lawrenceburg Energy Facility	06/07/01	Auxiliary Boiler	125	GCP	0.0054
OH-0310	American Municipal Power Generating Station	02/07/08	Auxiliary Boiler	150		0.0055
OH-0241	Miller Brewing Company - Trenton	05/27/04	Boiler (2)	238		0.0109
VA-0278	Virginia Commonwealth University East Plant	03/31/03	Boiler (3)	151	GCP	0.0139
AR-0070	Genova Arkansas I, LLC	08/23/02	Auxiliary Boiler	33	GCP	0.0180
TX-0437	Hartburg Power, LP	07/05/02	Auxiliary Boiler	40	GCP	0.0200
TX-0386	Calpine Amella Energy Center	03/26/02	Auxiliary Boiler	155		0.0200
TN-0089	Proctor & Gamble Manufacturing Company	03/05/01	Utility Boiler	225		0.0240
WI-0204	United Wisconsin Grain Producers-Ethanol Plant	08/14/03	Boiler /Oxidizer	140		0.0479
NJ-0043	Liberty Generating Station	03/28/02	Auxiliary Boiler	200	OC	50 ppm <sub>dv</sub>

**Footnotes**

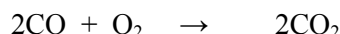
“GCP” means good combustion practices. “SCR” means selective catalytic reduction. “LNB” means low NOx burner. “ULNB” means ultra-low NOx burner. “FGR” means flue gas recirculation. “OC” means oxidation catalyst.

## 8.3 STEP 2. Identify Technically Feasible Control Technologies.

Available control technologies for the control of VOC emissions include good combustion practices, oxidation catalysts, and thermal oxidation.

### 8.3.1 Oxidation Catalysts.

Oxidation catalysts are used to reduce CO emissions, and to a lesser extent VOC emissions, from natural gas or oil-fired combustion turbines. Typical VOC reduction efficiencies in these combustion turbine applications are less than 50%. However, oxidation catalysts have limited demonstration in reducing VOC emissions from boilers. The CO oxidation catalysts are generally noble metal catalysts which are susceptible to poisoning from sulfur and calcium bearing compounds. These catalysts may experience deactivation and fouling in high sulfur oil-fired boiler flue gas streams. To be effective, the oxidation catalyst must be placed in a location with gas temperatures of at least 600 °F. Oxidation catalysts operate according to the following general reaction:



Typical excess oxygen (O<sub>2</sub>) levels in combustion turbines is 12 – 15%, compared to 3 – 6% in natural gas-fired boilers. These low excess O<sub>2</sub> levels will limit the effectiveness of the oxidation catalyst.

### 8.3.2 Thermal Oxidation

Thermal oxidation has never been required nor used on a natural gas-fired boiler, and its theoretical ability to reduce VOC emissions from these boilers is questionable. Thermal oxidation would involve injecting additional air into the flue gas and heating the oxygen enriched mixture to approximately 1,500 °F to oxidize VOC to carbon dioxide and water. However, since the combustion of the reheat fuel would itself result in VOC emissions, there is no evidence that thermal oxidation would result in any VOC emission reductions. Since thermal oxidation has never been demonstrated on a natural gas-fired boiler, and because there is no evidence that it could reduce VOC emissions, thermal oxidation is not a technically feasible VOC control technology for these boilers.

### 8.3.3 Good Combustion Practices

Good combustion practices or combustion controls generally include the following components:

1. Good air/fuel mixing in the combustion zone.
2. High temperatures and low oxygen levels in the primary combustion zone.
3. Overall excess oxygen levels high enough to complete combustion while maximizing boiler thermal efficiency.
4. Sufficient residence time to complete combustion.

In natural gas-fired boilers, good combustion practices is the only technically feasible CO control technology. Combustion efficiency is related to the three “T’s” of combustion: *Time, Temperature, and*

*Turbulence.* These components of combustion efficiency are designed into utility boilers to maximize fuel efficiency and reduce the highest single operating cost of a utility boiler: FUEL. A fourth critical parameter is the level of oxygen in the boiler, referred to as the excess air or excess oxygen level. Therefore, combustion control is accomplished primarily through boiler design as it relates to time, temperature, and turbulence, and through boiler operation as it relates to excess oxygen levels. Combustion design for modern boilers is intended to simultaneously minimize formation of CO, VOC, and NO<sub>x</sub> emissions. This is a difficult task, since emissions of NO<sub>x</sub> and emissions of CO (and VOC) are inversely related. That is, measures used to reduce NO<sub>x</sub> emissions often lead to increases in CO and VOC emissions. Therefore, the boiler design to minimize VOC emissions is interrelated with the boiler design to minimize NO<sub>x</sub> formation.

## **8.4 STEP 3. Rank the Technically Feasible Control Technologies.**

Based on the above analysis, the technically feasible VOC control technologies for these natural gas-fired boilers includes good combustion practices based on the use of the ultra low NO<sub>x</sub> burners combined with flue gas recirculation, and the use of oxidation catalysts as a post combustion control system. Good combustion practices are expected to limit VOC emissions to 0.006 lb/mmBtu, equal to 20 parts per million at 5% excess oxygen (based on VOCs as propane). The use of an oxidation catalyst is expected to reduce VOC emissions by 25%, to 15 parts per million, and 0.0045 lb/mmBtu.

## **8.5 STEP 4. Evaluate the Most Effective Controls.**

### **8.5.1 Rank No. 1: Oxidation Catalyst and Good Combustion Practices.**

The use of good combustion practices combined with an oxidation catalyst on these natural gas-fired boilers could reduce VOC emissions to 0.0045 lb/mmBtu. Based on limiting the operation of these boilers to 6,200 hours per year, this combination of controls could reduce VOC emissions from 3.3 tons per year, to 2.5 tons per year.

#### **8.5.1.1 Environmental Impacts.**

The primary environmental impact from the use of oxidation catalysts on these boilers is a reduction in CO and VOC emissions.

#### **8.5.1.2 Energy Impacts.**

Energy impacts from the use of an oxidation catalyst would include an increase in induced draft fan power requirements necessary to overcome a small pressure drop across the catalyst.

#### **8.5.1.3 Economic Impacts.**

The costs for oxidation catalysts on these boilers would include the capital costs for the catalyst and ancillary equipment, labor, auxiliary power requirements, catalyst replacement, maintenance, and

administrative costs. The oxidation catalyst cost analysis is included in Table 8-2. From Table 8-2, an oxidation catalyst system is expected to have an equipment cost of \$105,000 per boiler, and a total capital requirement of \$210,000. From Table 8-2, the oxidation catalyst system is expected to have an annual cost of \$136,100 for each boiler. The oxidation catalyst systems would reduce VOC emissions by 0.8 tons. Based on these costs, the oxidation catalyst systems would have an average cost effectiveness of \$170,000 per ton of VOC removed.

**TABLE 8-2. Oxidation catalyst control system costs for each natural gas-fired boiler.**

	<b>CAPITAL COST</b>	<b>ANNUAL COST</b>
<b>Total Capital Cost</b>		
Equipment Cost, 2010 Dollars	\$105,000	
Capital Recovery Factor, CRF	0.1098	
<b>Total Capital Investment (TCI)</b>	<b>\$210,000</b>	<b>\$23,100</b>
<b>Labor Costs (1 hour per day)</b>		
<b>Maintenance Costs</b>		
Maintenance Labor, hr/year	300	
Catalyst Inspection and Replacement Labor, hr per year	400	
Labor Cost, \$ per year	\$35,000	
Material Cost, \$ per year	\$35,000	
<b>Total Annual Maintenance Cost \$/yr</b>		<b>\$70,000</b>
<b>Catalyst Replacement Costs</b>		
Catalyst Cost	\$70,000	
Sinking Fund Factor	0.174	
<b>Total Catalyst Replacement Costs</b>		<b>\$12,200</b>
<b>Auxiliary Power Requirements</b>		<b>\$8,300</b>
<b>Overhead and Administrative Costs</b>	2% of TCI	<b>\$4,200</b>
<b>TOTAL ANNUAL COST</b>		<b>\$136,100</b>

**Footnotes**

1. The cost of capital for this project is 7%, and the project life is 15 years. The annual cost of this investment is given by the capital recovery factor (CRF):

$$CRF = \frac{i(1+i)^n}{[(1+i)^n - 1]} \quad \text{where:} \quad \begin{array}{l} i = \text{annual interest rate (decimal)} \\ n = \text{control system life (years)} \end{array}$$

2. For the catalyst, the catalyst life is 5 years. The annual cost is given by the sinking fund factor (SFF):

$$SFF = \frac{i}{[(1+i)^n - 1]}$$

3. The oxidation catalyst capital cost is based on the catalyst system equipment cost multiplied by 2.0 for the costs of installation and other necessary equipment..

#### **8.5.1.4 Conclusion.**

The use of an oxidation catalyst in combination with good combustion practices on these natural gas-fired package boilers can achieve VOC emission rates of 0.0045 lb/mmBtu. However, each oxidation catalyst system would have a total capital requirement of \$210,000, and a total annual cost of \$136,100. The oxidation catalyst systems would reduce VOC emissions by 0.8 tons per year, resulting in an average cost effectiveness of \$170,000 per ton of VOC removed. This is a very high cost, indicating that the use of an oxidation catalyst for the control of VOC emissions on these natural gas-fired boilers is not an economically feasible control option.

#### **8.5.2 Rank No. 2: Good Combustion Practices.**

The use of package boilers with Ultra Low NO<sub>x</sub> Burners, Overfire Air, and Flue Gas Recirculation, and the use of good combustion practices can achieve a VOC emission rate of 0.006 lb/mmBtu. Based on limiting the annual heat input to each boiler to no more than 1,085,000 mmBtu per year (equal to 2,170,000 mmBtu per year for both boilers combined), the use of good combustion practices will limit VOC emissions from each boiler to 3.3 tons per year.

### **8.6 STEP 5. Proposed VOC BACT Determination.**

Based on this analysis, We Energies has concluded that the use of good combustion practices represents the best available control technology (BACT) for the control of VOC emissions from these natural gas-fired package boilers. Based on this analysis, We Energies proposes the following limits as BACT for the control of VOC emissions from the natural gas-fired boilers.

- (1) Volatile organic compounds (VOC) emissions from the natural gas-fired boilers B02 and B03 shall be controlled using good combustion practices as the best available control technology.
- (2) Volatile organic compounds (VOC) emissions may not exceed 0.0060 pounds per million Btu of heat input.
- (3) Compliance with these emission limits shall be based upon the U.S. EPA Reference Method 25A, or another method approved in writing by the department.
- (4) The total heat input to boilers B02 and B03 combined may not exceed 2,170,000 mmBtu in any consecutive 12-month period.

# Chapter 9. Fluorides Control Technology Review.

Fluorine (F) is a trace element in natural gas. When these fuels are burned, fluorine may be emitted as hydrogen fluoride or hydrofluoric acid (HF), or as fluorine compounds, such as sodium fluoride (NaF) and calcium fluoride (CaF<sub>2</sub>). Fluoride compounds such as NaF are solids at the flue gas temperatures. On the other hand, hydrogen fluoride is a colorless liquid at temperatures less than 66 °F. At temperatures above 66 °F, hydrofluoric acid is a gas. Because hydrofluoric acid is soluble in water and is a strong acid, it readily combines with the alkaline substances in ash.

## 9.1 BACT Baseline.

There are no specific NSPS or SIP emission limitations for fluoride emissions from natural gas-fired boilers. Therefore, the BACT baseline is the uncontrolled emission rate.

## 9.2 STEP 1. Identify All Potential Control Technologies

Based on the permits reviewed, there were no natural gas-fired boilers with hydrogen fluoride (HF) emission limits. In January, 2010, a preliminary database of emission test data, CEMS data, and fuel analysis data for boilers at major sources of HAP was made available at <http://www2.ergweb.com/projects/combustion/combustiontesting.html>. This data includes emission data from the U.S. EPA's Phase I survey and the Phase II test plan. HF stack test data for natural gas and distillate fuel oil is summarized in Table 9-1. There was no fluorine fuel data for natural gas.

**TABLE 9-1. Natural gas and distillate fuel oil-fired boiler hydrogen fluoride (HF) test results.**

State / Facility ID	Non-Detect?	Value, lb/mmBtu	Fuel
UT Westinghouse	BDL	0.000004	Natural gas
SC GP Chem Russellville	ND	0.000020	Diesel fuel
IN Nucor Steel		0.000078	Natural gas
IN Alcoa Warrick	BDL	0.000091	Natural gas
CO Rocky Mtn Steel 212		0.00013	Natural gas
IN Outokumpu Stainless Plate	ND	0.00045	Natural gas
MI Consumer Energy Co- Campbell	ND	0.00058	No. 2 Distillate
TN Invista Chattanooga	ND	0.00062	No. 2 Distillate
IN Arcelor Mittal Burns Harbor	ND	0.0009	Natural gas
WI Charter Steel	ND	0.0010	Natural gas
NC Domtar	ND	0.0010	No. 2 Distillate
IL Poly One		0.0016	Natural gas
NC Camp Lejeune MCB		0.0078	Natural gas
SC Eastman Colombia	ND	0.069	Natural gas
SC Michelin Sandy Springs	ND	0.071	Natural gas

Emission rates ranged from less than 0.000004 to 0.071 lb/mmBtu, a range of 4 orders of magnitude. Of the 15 listed emission test results, only 4 results indicated emissions above the detection limit. In addition, the two highest reported values were also below the detection limit of the test. The median value in Table 9-1 is 0.00062 lb/mmBtu.

Based on the above data, the median value from Table 9-1 is 0.00062 lb/mmBtu. This value may be used to estimate HF emissions from natural gas combustion.

### **9.3 STEP 2. Identify Technically Feasible Control Technologies.**

As noted above, fluoride emissions may be emitted as solids, such as sodium fluoride, or as the acid gas hydrogen fluoride. Therefore, fluoride emissions may be controlled using particulate matter control systems, and also acid gas control systems. Technologies that may control fluoride emissions include fabric filter baghouses, electrostatic precipitators, wet or dry FGD systems, and sorbent injection.

#### **9.3.1 Flue Gas Desulfurization Systems.**

Wet and dry flue gas desulfurization systems are effective fluoride control systems when combusting coal. From the EPRI report, *Emission Factors Handbook: Guidelines for Estimating Trace Substance Emissions from Fossil fuel Steam Electric Plants*, Final Report, April, 2002, the expected HF control efficiency for all coal-fired FGD systems is 94%. Since we are not aware of any FGD systems on natural gas-fired boilers, there is no available data on HF emission reductions which may occur with the use of FGD systems.

#### **9.3.2 Sorbent Injection.**

Sorbent injection such as hydrated lime may also reduce emissions of HF. The injection of lime into the flue gas upstream of a fabric filter baghouse is well demonstrated to reduce H<sub>2</sub>SO<sub>4</sub> emissions. Again, since we are not aware of any FGD systems on natural gas-fired boilers, there is no available data on HF emission reductions which may occur with the use of sorbent injection.

### **9.4 STEP 3. Rank The Technically Feasible Control Technologies.**

From the above discussion, there is no available data to suggest that post combustion pollution control systems can reduce HF emissions below the very low levels which occur from the combustion of only natural gas. Therefore, the highest ranked control is the combustion of low fluorine containing fuels including natural gas.

### **STEP 4. Evaluate the Most Effective Controls.**

Based on the above analysis, the combustion of low fluorine containing fuels including natural gas represents the best available control technology for these package boilers. Further reduction from potential acid gas control systems cannot be confirmed.

## **STEP 5. Proposed Fluorides BACT Determination**

Based on this analysis, We Energies has concluded that the use of low fluorine containing fuels including natural gas represents the best available control technology (BACT) for HF emissions from these natural gas-fired package boilers. Based on this analysis, We Energies proposes the following limits as BACT for the control of fluoride (HF) emissions from the natural gas-fired boilers. The available data covers a very wide range of potential emission rates. Therefore, rather than specifying a specific allowable emission limit, We Energies proposes the following limits as BACT for the control of HF emissions from the natural gas-fired boilers.

- (1) Hydrogen fluoride (HF) emissions from the package boilers shall be controlled using low fluorine containing fuels including natural gas as the best available control technology.