Analysis of Combustion Controls for Reducing NO_x Emissions From Coal-fired EGU's in the WRAP Region

Draft Report

Prepared for
The Western Regional Air Partnership

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ACRONYMS

AOFA	Advanced over fire air (installed since 1990)
BART	Best available retrofit technology
CADM	Compartment air distribution monitoring system
CAMD	Clean Air Markets Division of the U.S. Environmental Protection Agency
CO	Carbon monoxide
CCOFA	Close coupled over fire air
EGU	Electric generating units
EIA	Energy Information Administration
	GNOCIS generic NO_x control intelligent system
kW	Kilowatt
LNB	Low NO_x burner
LNBO	Low NO_x burner and over fire air
LNC1	Tangential low NO_x burner with close coupled over fire air
LNC2	Tangential low NO_x burner with separated over fire air
LNC3	Tangential low NO_x burner with separated and close coupled over fire air
LNCB	Low NO_x cell burner
NSPS	New Source Performance Standards
ECT	Electric charge transfer
MMBtu	Million British thermal units
MW	Megawatt
O&M	Operation and maintenance
OFA	Over fire air (installed prior to 1990)
OEC	Oxygen enhanced combustion
PSD	Prevention of significant deterioration permit program
ROFA	Rotating opposed fire air
SCR	Selective catalytic reduction
SOFA	Separated over fire air
ULNC4	Advanced tangential low NO_x control with separated and close coupled over fire air
WRAP	Western Regional Air Partnership

EXECUTIVE SUMMARY

[To be added]

1.0 INTRODUCTION

1.1 Background

To reduce haze, and to meet requirements of the Clean Air Act, the U.S. Environmental Protection Agency (EPA) issued a regional haze rule aimed at protecting visibility in 156 class I federal areas in 1999. Under the Regional Haze Rule, states are required to set periodic goals for improving the visibility in these areas. As they work to reach these goals, states must develop implementation plans that contain enforceable measures and strategies for reducing visibility-impairing pollution. The Western Regional Air Partnership (WRAP) is a voluntary organization of western states, tribes and federal agencies. The states included in the WRAP are Alaska, Arizona, California, Colorado, Idaho, Montana, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. The purpose of the WRAP is to develop the technical and policy tools needed by western states and tribes to comply with the Regional Haze Rule.

As part of its directive, the WRAP has undertaken a program to assess air emissions control technologies and strategies for large stationary sources of NO_x in the western States region. The largest source of NO_x emissions from this area is electric generating units (EGU's), which comprise 72 percent of the total NO_x emissions. Emissions from coal-fired EGU's comprise 93 percent of the NO_x emissions from EGU's, and 65 percent of the emissions from all NO_x stationary sources. Because of the large amount of NO_x attributed to coal-fired EGU's, this report focuses on them. NO_x emissions from non-EGU's, and emissions of other pollutants are presented in other documents.

1.2 Objectives and General Methodology

The purpose of this report is to present the possible combustion controls for coal-fired EGUs and the costs and emission reductions associated with these controls. A previous study conducted by WRAP identified potential controls applicable to stationary sources of PM and NO_x.[1] The EPA's Clean Air Markets Division (CAMD) has also conducted studies on the costs and emission reductions of various NO_x combustion controls that could be used to meet the requirements of the Regional Haze Rule. This report updates the previous studies, includes information on newer technologies, and estimates more unit specific costs and emission reductions.

To conduct the cost and emission reduction analyses, the following steps were followed:

1. A database was created to characterize the coal-fired EGU's. Parameters that were reviewed included fuel burned, size, existing controls, baseline emissions, and combustor specific properties, such as residence time.

2. A literature search and data review were conducted to obtain information on the performance and cost of NO_x combustion controls currently in use in the WRAP units, and newer state of the art combustion controls that are in commercial use.

3. EGU's were grouped into subcategories/bins to identify similar units

4. Control options were developed for each bin based on the NO_x combustion control review

5. Cost and emission impacts were calculated for each EGU based on the control options.

Each of the steps is discussed in detail in this report.

2.0 NO_x EGU'S IN WRAP

This section discusses the data sources used to develop a database of coal-fired EGU's located in the WRAP states. The characteristics of these units are also illustrated with statistics on the size, location, type of combustor, age, and amount of NO_x emitted.

2.1 Data Sources

The U.S. Department of Energy's (DOE) Energy Information Administration (EIA) requires EGU's to provide source specific information in various survey forms. The clean air markets division (CAMD) of EPA also gathers unit specific information and publishes information on their website.[2, 3, 4] Much of the information is extracted from the EIA forms. Additionally, the CAMD requires units that are in the Acid Rain Program to submit NO_x continuous emissions monitoring (CEM) information. A spreadsheet compiled by CAMD was also submitted to the WRAP.[5] This spreadsheet contains similar information to the website database, but also provides unit-specific parameters not on their website.

A list of the unit specific information available from these data sources is presented in Table 2-1. The EIA forms contain additional data that is not included because it was not considered relevant for this study. Unit specific information is available from both EIA and CAMD for the years 2001, 2002, and 2003. Information for all data fields was not always available for specific units. Appendix A contains a complete listing of EGU's in the WRAP states and all the unit specific information gathered for them.

Table 2-1. Information Obtained from Data Sources

Data Field	Data Source				
	CAMD-spreadsheet	CAMD website	EIA 767[a]	EIA 423[b]	Calculated Based on Data Provided
Utility Owner Name	✔	✔	✔		
Plant ORIS Code	✔	✔	✔		
Plant Name	✔	✔	✔		
Plant State	✔	✔	✔		
Boiler ID	✔	✔	✔		
Bin ID					✔
Nameplate Capacity (kW)	✔				
2003 Estimated Actual Capacity					✔
Combustor Type	✔	✔	✔		
Pre-Baseline Control NO_x Emission Rate	✔				
Avg Pre-Control NO_x Emission Rate	✔				
2001 Average NO_x Rate (lb/MMBtu)		✔			
2002 Average NO_x Rate (lb/MMBtu)		✔			

Table 2-1. Information Obtained from Data Sources (Continued)

Data Field	Data Source				
	CAMD-spreadsheet	CAMD website	EIA 767[a]	EIA 423[b]	Calculated Based on Data Provided
2003 Average NO_x Rate (lb/MMBtu)		✔			
NO_x Rate Average 2001-2003 (lb/MMBtu)					✔
Baseline NO_x Control Description	✔		✔		
NO_x Tons Emitted in 2001		✔			
Generation of Baseline NO_x Equipment					✔
NO_x Tons Emitted in 2002		✔			
NO_x Tons Emitted in 2003		✔			
Average NO_x Tons Emitted 2001-2003					✔
2001 Average Heat Input (MMBtu)		✔			
2002 Average Heat Input (MMBtu)		✔			
2003 Average Heat Input (MMBtu)		✔			
2001-2003 Average Heat Input (MMBtu)					✔
Coal Mine State				✔	
Boiler Status (operating or not operating)			✔		
Regulation for NO_x (Federal, State, Local)			✔		
Numerical Emission Standard for NO_x			✔		
Unit for Numerical NO_x Standard			✔		
Period of Time Over Which Standard is Measured			✔		
Year Unit Complied with NO_x Standard			✔		
Strategy to Meet NO_x Standard (1)			✔		
Strategy to Meet NO_x Standard (2)			✔		
Strategy to Meet NO_x Standard (3)			✔		
Type of NO_x Standard Unit is Operating Under					
Inservice Date			✔		
Retirement Date			✔		
Primary Fuel (1)			✔		
Primary Fuel (2)			✔		
Primary Fuel (3)			✔		
Wet or Dry Bottom			✔		
Status of NO_x Control Equipment (operating or not operating)			✔		
Low NO_x Control Process (1)			✔		
Low NO_x Control Process (2)			✔		
Low NO_x Control Process (3)			✔		

Table 2-1. Information Obtained from Data Sources (Continued)

Data Field	Data Source				
	CAMD-spreadsheet	CAMD website	EIA 767[a]	EIA 423[b]	Calculated Based on Data Provided
Manufacturer of Low NO_x Equipment			✔		
Manufacturer of Boiler			✔		
Hours Boiler Under Load			✔		
BART Analysis from ERG					✔

[a] The EIA Form 767 contains information on steam-electric plants.
[b] The EIA Form 423 contains information on fuel cost and quality used at the electric plants.

2.2 Data Sources for Existing NO_x Combustion Controls

Information on controls currently used on EGUs in the WRAP states was available from three different data sources: the CAMD spreadsheet submitted to WRAP, the CAMD online database, and the EIA 767 data form.[2,3,5] The CAMD spreadsheet contains information on existing controls as well as cost and emission reduction estimates for various control options. The CAMD spreadsheet appears to be the most detailed of the data sources and often includes installation dates of combustion control installations or retrofits. This specificity is necessary to determine the generation of a Low NO_x burner (LNB) or over fire air (OFA) equipment currently installed on the EGU. For instance, burners installed during the 1970s or 1980s were first generation LNB's. These burners will tend to have a less efficient NO_x removal capacity than burners installed in more recent years. Tangentially-fired units that have a LNB coupled with OFA are also referred to in the spreadsheet as a form of Low NO_x Control (LNC).

The CAMD website database also lists control information. However, installation dates are not provided. Control information, like NO_x emission information from CEMs, is reported annually to CAMD. The CAMD website data does not document NO_x trim technologies such as low excess air or burners out of service. In some instances a baseline control category of 'Other' indicates a NO_x trim technology or other combustion modification that is not as major as an OFA or LNB, such as new Low NO_x coal nozzles. An exhaustive list of the possibilities of the 'Other' control category is not available.

The EIA 767 data form has a similar categorization of NO_x combustion controls as the CAMD spreadsheet and online database. Unlike the CAMD online database, NO_x trimming technologies such as low excess air and biased firing, are included in the EIA 767 form. Additionally, NO_x combustion controls on tangentially-fired units are categorized on the EIA form by one of three methods: LNB, OFA, or Low NO_x Burner and over fire air (LNBO) instead of being assigned to an LNC1, LNC2, or LNC3 category as in the spreadsheet.

A comparison of the controls listed in the EIA 767 form with the two sources of CAMD data revealed **22** mismatches of baseline control categories. Some of these mismatches were eliminated by calling and verifying baseline NO_x controls with the source. Table 2-2 lists the control mismatches that still exist after incorporating information from the sources contacted. This table excludes the mismatches that occurred because a lack of corresponding categories between the CAMD data and EIA 767 data for tangentially-fired units or units that listed a NO_x trimming technology in conjunction with a control category.

Table 2-2. Baseline NO_x Control Mismatches Between CAMD and EIA Data Sources

Plant State	Plant Name	ORIS Code	Boiler ID	CAMD Online Database Baseline NO_x Control	CAMD Spreadsheet Baseline NO_x Control	EIA 767: Low NO_x Control Process
NV	Reid Gardner	2324	4	LNBO	LNBO	Low NO_x Burner
CO	Cameo	468	2	LNBO	LNBO	Low NO_x Burner
MT	Colstrip	6076	1	OFA	OFA	Low NO_x Burner
MT	Colstrip	6076	2	OFA	OFA	Low NO_x Burner
MT	Lewis & Clark	6089	B1	LNC1	LNC1	Not Applicable
WY	Wyodak	6101	BW91			Low NO_x Burner

Given the specificity of the control data from CAMD spreadsheet, the control information listed in it was assumed when there was a mismatch in controls from the data sources.

2.3 Additional Data Collection

NO_x emissions and the types of combustion controls that may be applicable are also dependent on fuel specific information (fuel moisture and nitrogen content), and additional combustor specific information (combustor volume, heat release rate, coal residence time, carbon monoxide limit, and whether the furnace is single or twin). Fuel moisture and nitrogen content affect the formation of fuel NO_x released. For example, low nitrogen fuels, such as powder river basin coal, typically have lower NO_x emissions. The combustor volume, heat release rate, and residence time all affect the formation of thermal NO_x. However, the fuel and additional combustor information is not readily available from EPA or EIA databases. Consequently, a telephone survey was conducted to obtain this data from utilities in the WRAP. The data obtained from the surveys is presented in Appendix B. At this time, insufficient information was obtained to assess the effect of fuel specific and combustor specific parameters on NO_x Emissions. Vendors held combustor-specific data such as residence time proprietary.

2.4 Population of EGU's in WRAP States

Databases maintained by EIA and CAMD show there are 110 coal-fired EGU's in the WRAP states. Seven out of the 110 units are identified in the EIA database but not in the CAMD database. As a result, these seven units have combustor and fuel type information, but they lack NO_x emission information. The distribution of coal-fired EGU's in the WRAP region is presented in Table 2-3. The majority of coal-fired units are in Colorado (22 units), followed by Wyoming (17 units) and Arizona (14 units).

Table 2-3. Distribution of Coal-fired EGU's by WRAP State[a]

State	Number of Units	2001-2003 Avg. NO_x Emissions (TPY)
AK	5	1580[a]
AZ	14	81,354
CA	1	298[a]
CO	22	69,266
MT	6	37,170
ND	13	76,788
NM	10	76,316
NV	8	37,122
OR	1	9,750
SD	1	15,779
UT	10	70,556
WA	2	18,064
WY	17	83,797
Total	**110**	**577,840**

[a] Emissions data was not available from CAMD for these units. Actual emissions from 2002 National Emissions Inventory is shown.

The average annual NO_x emissions gathered by CAMD from 2001 to 2003 are also presented in Table 2-3, where not available emissions data from the National Emissions Inventory was used. The majority of emissions (80 percent) are spread out over six states: Wyoming, Arizona, North Dakota, New Mexico, Utah, and Colorado.

A previous study done for WRAP identified units considered to be BART-eligible based on in-service date and NO_x emissions level. Sixty percent of coal-fired units (64 units) in the WRAP region were identified as definitely BART eligible. Several other units (21), as discussed in the BART report, were identified as likely or probable candidates for BART-eligibility. These BART-eligible units are distributed similarly to the total population of EGUs based on combustor, fuel, and location characteristics of the units.

2.5 Characteristics of EGU's

The EIA forms require information to be submitted on the state where the burned coal is mined. However, the EIA forms did not provide the coal mine state for all EGU's. For this study it was assumed, unless otherwise reported in the EIA forms or other data sources, that EGU's in Wyoming typically fire a Powder River Basin (PRB) sub-bituminous coal due to the location of these coal mines. The distribution of units burning each type of coal is summarized in Table 2-4. The table indicates that NO_x emissions from boilers firing sub-bituminous coals not from the PRB sources accounts for half the NO_x emissions.

Table 2-4. Distribution of Coal-fired EGU's by WRAP State and Coal Type

Coal Type	Plant State	Number of Units	2001- 2003 Avg. NO_x Emissions (TPY)
Western Bituminous	AZ	4	35,397
	CA	14	298[a]
	CO	9	22,344
	NV	6	17,845
	UT	10	70,556
Lignite	MT	1	873
	ND	14	76,788
Sub-bituminous: Powder River Basin or Other Specified Low Nitrogen Content Fuel	CO	5	16,363
	MT	4	23,834
	NM	1	3,535
	WY	16	78,824
Other Western Sub-bituminous	AZ	10	45,957
	CO	8	30,560
	MT	1	12,462
	NM	9	72,781
	NV	2	19,278
	OR	1	9,750
	SD	1	15,779
	WA	2	18,064
	WY	1	4,973
Unknown	AK	5	1580[a]
Totals		**Units**	**2001-2003 Avg. NO_x Emissions (TPY)**
Bituminous		30	146,440
Lignite		13	77,661
PRB or Low Nitrogen Sub-bituminous		25	121,235
Other Sub-bituminous		36	230,924
Unknown		5	1580[a]

[a] Emissions data was not available from CAMD for these units. Actual emissions from 2002 National Emissions Inventory is shown.

The CAMD and EIA databases also contain combustor specific information, such as the heat input and capacity of the boiler and type of burner used. Table 2-5 summarizes the annual average NO_x emissions and number of units associated with each type of combustor.

Table 2-5. Distribution of Combustor Types for Coal-fired EGUs in WRAP

Combustor Type	Number of Units	Total Capacity [MW]	2001-2003 Avg. Annual NO_x Emissions [TPY]
Tangentially-fired	44	19,022	257,400
Dry bottom wall-fired (including turbo-fired)	45	13,805	212,847
Cyclone	5	1,899	62,780
Cell burner	3	1,865	33,425
Dry bottom vertically-fired	4	354	7,251
Circulating Fluidized Bed	3	188	2,557[a]
Unknown	5	35	1,580[a]

[a] Emissions data not included in the CAMD information was supplemented with emissions from the 2002 National Emissions Inventory.

Table 2-6 presents the baseline emissions and distribution of boilers associated with various EGU capacity ranges.

Table 2-6. Size Distribution of Coal-fired EGU's in WRAP

Size Range (MW)	Total Capacity (MW)	Number of Units	2001-2003 Avg. Annual NO_x Emissions (TPY)
Less than 100	550	13	10,251[a]
100-300	7,182	38	131,085
300 to 500	11,994	29	188,987
500 to 700	7,105	13	93,583
Greater than 700	10,337	13	152,478
Unknown		4	1,459[a]

[a] Emissions data not included in the CAMD information was supplemented with emissions from the 2002 National Emissions Inventory when CAMD data was not available.

Table 2-7 presents the number of coal-fired EGUs in the WRAP region that have been operated over approximately the last 55 years. The number of new coal-fired units peaked in the 1970s.

Table 2-7. Distribution of Coal-fired EGU's in WRAP Over the Last 50 Years

Unit In-Service Date	Number of Units	2001-2003 Annual Average NO_x Tons
Prior to 1960	11	13,126[a]
1960 to 1969	23	77,031[a]
1970 to 1979	39	274,484[a]
1980-1989	30	202,530
1990-1991	3	7,846[a]
No Date Supplied	4	2,823

[a] Emissions data not included in the CAMD information was supplemented with emissions from the 2002 National Emissions Inventory when CAMD data was not available.

3.0 NO$_x$ COMBUSTION CONTROL TECHNOLOGIES

This section provides both the current combustion control technologies used to control NO$_x$ emissions at EGUs in the WRAP states and newer state of the art combustion controls that are commercially available.

3.1 Existing Combustion Control Technologies

Table 3-1 summarizes the NO$_x$ combustion control technologies currently in use in the WRAP states. The controls in place for each EGU are provided in Appendix A. The majority of wall-fired units utilize an LNB. Of those units with an LNB, approximately half were installed during the first part of the 1990s. The remaining half of the burner installations were split between the mid-1970s and 1990 and since 1997. This indicates half of the LNBs in the WRAP are 2nd generation, 38 percent are 1st generation and 20 percent are modern LNB units.

Table 3-1. Distribution of Baseline NO$_x$ Combustion Controls for Coal-fired WRAP EGUs

Baseline NO$_x$ Control	Combustor Type			Coal Type			
	Wall-fired	Tangential	Other (including unknown)	Bituminous	Sub-bituminous	Lignite	Unknown
None Listed	4	9	14	3	13	6	5
LNB	22	3	2	8	15	4	
LNBO	13		2	7	8		
LNC1		12		4	7	1	
LNC2		2			1	1	
LNC3		7		3	2	2	
OFA	5	8	2	1	14		
SCR	1				1		
Other		3	1	4			
Total	45	44	21	30	61	14	5

LNB = Low NO$_x$ burner, this includes an older low technology found on some tangentially-fired boilers and a technology used on tangential units.
LNBO = Low NO$_x$ burner with over-fire air
LNC1 = Low NO$_x$ burner with closed-coupled OFA
LNC2 = Low NO$_x$ burner with separated OFA
LNC3 = Low NO$_x$ burner with close-coupled and separated OFA
OFA = Over-fired air
SCR = Selective Catalytic Reduction

Many tangentially-fired units utilize close-coupled over fire air (CCOFA). Approximately half of these units using CCOFA also operate with a low NO$_x$ firing system. The majority of tangentially-fired units with the low NO$_x$ firing systems were installed between 1980 and 1997. A comparison of the baseline controls between wall-fired and tangentially-fired units reveals 20 percent of tangentially fired units are without a baseline NO$_x$ combustion control compared to 9 percent of wall-fired units without baseline NO$_x$ combustion controls. A detailed discussion of the effectiveness and cost of the existing NO$_x$ combustion controls is presented below.

3.1.1 *Wall-fired Units*

Low NO_x Burners

First-Generation. Burners installed on WRAP units during the 1970s to1980s are assumed to be first-generation LNBs with a single air zone or a simple dual air zone. Models such as the Babcock and Wilcox DRB or the Foster Wheeler CF burner are examples of LNBs from this era. First-generation burners can achieve up to 30 percent reduction in NO_x emission rates according to information supplied by a vendor.[6] First-generation LNBs are no longer used in burner retrofits.

Second-Generation. The second-generation LNB has dual air zones and better control of the secondary air supplied to each burner from the addition of a sliding air damper. This generation of burners was introduced at the end of the 1980s and was used through the 1990s. Examples of this burner generation are the Babcock and Wilcox DRB-XCL model and the Foster Wheeler CF-SF model. Technical literature from the vendors indicated second generation LNBs achieve between 50 and 65 percent reductions in NO_x compared to uncontrolled conditions.[7]

Post 1997. In response to increased competition at the end of the first phase of the CAA, vendors of LNBs continued to improve designs by focusing on reducing the complexity of burner installations and maintenance. Additional improvements have included reducing the size and amount of material for a given burner type in order to reduce material costs and make burners applicable to a wider variety of units, including those units with closer-spaced burners. Although evolutions in burner design achieve a modest 11 percent reduction in NO_x compared to 2nd generation LNBs, the competition and improved burner designs has resulted in delivering burners with substantial reductions in costs since the burners installed in the mid-1990s. Specific examples of these next generation low NO_x burners are discussed in Section 3.2. Based on the more recent technical information from vendors and a current overview of NO_x technologies provided from an engineering firm estimates, the current installed capital costs of modern low NO_x burners is between $6 and $11 per kilowatt.[7, 12] These costs are significantly lower than the $19.56 per kilowatt installed costs of LNBs used in the CAMD analysis.

Over Fire Air

First Generation. Over fire air (OFA) is a technique where a portion of the air used in the combustion process is diverted to areas adjacent to the burners in order to extend the combustion process. As a result, furnace temperatures are lowered and oxygen levels are decreased within the combustion zone, thus lowering the formation of NO_x. Original OFA systems were simple holes in the furnace wall. These systems did not have separated boosted fan systems associated with them or the ability to control the direction or speed of the air flow. This original configuration of OFA is no longer being installed on units.

AOFA. Since the early to mid-1990s, boosted over fire air systems, initially referred to as advanced over fire air (AOFA) for Foster Wheeler units, began to be operated. This OFA system can be installed over the existing windboxes for retrofit installations. The AOFA system adds air ports to several walls of the furnace, in addition to just the burner walls. Due to fan systems and extra air ports, more air flow can be diverted than in the original OFA system. The extensive placement of ports in an AOFA system also allows air to be diverted to a greater amount of the furnace interior. The NO_x removal efficiency of this AOFA system is 15 to 25 percent NO_x removal compared to the baseline case (either uncontrolled or with a LNB) and approximately 20 percent additional NO_x removal compared to a LNB stand alone control.[7] It was assumed that all OFA systems installed after 1990 were AOFA and those installed earlier were OFA systems. Of the wall-fired units with OFA 11 were assumed to be AOFA. AOFA remains to be a practical combustion control retrofit technology. Based on vendor data, the installed capital cost of a Foster Wheeler AOFA system is $8.80 per kilowatt based on a 500 MW size unit.[7] This data is comparable to the installed capital costs used by CAMD for an OFA retrofit, scaled to 2004 dollars are $6.17 per kilowatt.

Low NO_x Burners and Over Fire Air (LNBO)

While either LNBs and AOFA can be used as a stand alone NO_x control, LNBs and OFA can also work together to reduce NO_x formation. Thirteen WRAP EGOs have an existing LNBO NO_x control.

The combination of these two NO_x combustion controls have the limitations associated with the generations of each component. For example, a unit with an early generation of OFA could be retrofitted with a modern LNB, resulting in a LNBO NO_x control system.

For units with an existing LNBO, a practical retrofit could replace the existing burner with modern LNB, update the OFA to an AOFA or replace the entire system. The installed capital costs used by CAMD for a retrofit of a new LNBO system (low NO_x burner and AOFA) are estimated at $23.43 per kilowatt. The installed capital costs of a Foster Wheeler LNBO retrofit are estimated at 18.80 per kilowatt. This difference is attributable to the substantial cost reductions in low NO_x burners since the basis for the CAMD cost data on low NO_x burners was compiled**.**[11]

3.1.2 *Tangential Units*

Low NO_x Systems[8, 9]

In contrast to the generations associated with LNBs on wall-fired units, low NOx systems have evolved by adding additional OFA controls to the unit. LNC1, 2, and 3 systems build upon each other which results in increased costs and emission reductions.

LNC1. Tangential units constructed prior to the original NSPS effective date, September 18th 1978, were not required to have any in-windbox control, while units built post-NSPS were required to meet an emission limit that would most likely be met by installing a LNB with close-coupled OFA (CCOFA), which is equivalent to a LNC1 system. The majority of tangentially-fired units in the WRAP with a LNC system have a LNC1, however no more

LNC1 controls have been installed since before the 1990s. This control, due to its limited reductions compared to other levels of LNC, is not a practical retrofit option for achieving a low enough NO_x limit for this analysis. However, an appropriate retrofit option for units with a LNC1 baseline NO_x control would be an upgrade to a LNC3 system. This upgrade consists of adding the SOFA component to the existing LNB and CCOFA. Since this upgrade requires only part of the materials for an LNC3, the costs associated with this retrofit are the difference between the costs for a LNC1 system and an LNC3 system. Based on information in the CAMD analysis, this upgrade is expected to cost about $6 per kilowatt, or the difference of $16 for a LNC3 system installation and $10 for a LNC1 installation. Another appropriate retrofit option would be to remove and replace the existing LNC1 with a LNC3, which is discussed under LNC3.

LNC2. A LNC2 level of control refers to a LNB with separated OFA (SOFA). Only two of the WRAP EGUs have a LNC2 listed as the baseline control. According to conversations with vendors, this retrofit option is practical for units with no existing baseline combustion. The costs supplied by the vendors for a LNC2 retrofit are in the range of $10-15 per kilowatt, which corresponds to the same cost assumptions used in the CAMD analysis. The NO_x removal efficiency of a LNC2 is between 47 and 60 percent compared to an uncontrolled state.

LNC3. An LNC3 system refers to a LNB with both CCOFA and SOFA. This LNC3 system can achieve 55 to 60 percent reductions in NO_x and will cost $12-18 per kilowatt. These costs are comparable to the $16.45 per kilowatt costs used in the CAMD analysis. While a LNC1 or LNC3 may upgrade to a LNC3, often times older LNC systems will most likely replace both the burner and OFA components unless the system was installed after the mid-1990s. The full replacement of a NO_x control system in lieu of an upgrade to a higher level of NO_x control occurs in order to take advantage of the greater NO_x reduction efficiencies, up to an additional 10 percent reduction, that can be achieved with more modern burner and OFA equipment. Another practical retrofit option is to follow the progression of Low NO_x burners to the next level, ULNC4 controls. This advanced tangential low NO_x system is discussed in Section 3.2.

Tangential units constructed prior to the original NSPS effective date, September 18th, 1978, were not required to have any in-windbox control, while units built post-NSPS were required to meet an emission limit that would most likely be met by installing a LNB with close-coupled OFA (CCOFA), denoted in the CAMD spreadsheet as a LNC1 control. Presently, tangentially-fired units in the WRAP with some form of combustion control have a combination of LNC1, 2, and 3 systems. LNC2 systems refer to an LNB with separated OFA (SOFA) and LNC3 systems refer to an LNB with both close-coupled and separated OFA. The most prevalent existing NO_x control for tangentially-fired units is the LNC1; however, LNC2 and LNC3 systems have been installed on units throughout the 1990s.

The efficiencies of the three levels of LNC for tangentially-fired units are documented in vendor technical literature (based on Alstom vendor performance on a 200 MW unit) and the CAMD analysis. Compared to an uncontrolled state, the LNC1 can achieve 40 to 50 percent reductions in NO_x, whereas the LNC2 can achieve 47 to 60 percent reductions and the LNC3 55 to 65 percent reductions.

Over Fire Air

For coal-fired units in the WRAP, 8 out of the 44 tangentially-fired units have only OFA listed in their baseline NO_x control category. Seven of the eight units had OFA installed prior to 1990. However, insufficient information was obtained to indicate the effectiveness, use, and cost of over fire air on tangential units. A possible retrofit for units with an OFA baseline is a conversion or upgrade to the low NO_x systems discussed above.

3.1.3 *Other Combustors*

Cell Burners-Low NO_x Burners

Two of the three coal-fired cell burner units in WRAP have a low NO_x cell burner (LNCB) that was installed at the end of the 1980s and early 1990s. These two units achieve an estimated 38 to 56 percent reduction compared to estimated NO_x levels prior to the low NO_x cell burner control. One practical and efficient retrofit control is a modern low NO_x cell burner, which will be discussed in the state of the art control section below.

Cyclone Furnaces

There are five cyclone furnaces in the WRAP states. None of these units are controlled.

Table 3-2 provides information on the expected emissions reductions of these traditional controls.

Table 3-2. Summary of NO_x Removal Efficiency Assumptions for NO_x Controls

Unit Type/NO_x Combustion Controls/Fuel Type			Vendor Information
	Maximum Expected NO_x Reduction	Minimum Limit Achieved (lb/MMBtu)	Fraction of Removal From Uncontrolled NO_x Emissions
Dry Bottom Wall-fired			
OFA - All Coals	15%		15 to 25%
LNB – Bituminous	57%	0.32	50 to 65%
LNB - Sub-bituminous/Lignite	57%	0.18	
LNBO – Bituminous	72%	0.32	68%
LNBO – Subituminous/Lignite	72%	0.18	

Table 3-2. Summary of NO_x Removal Efficiency Assumptions for NO_x Controls (Continued)

Unit Type/NO_x Combustion Controls/Fuel Type	Maximum Expected NO_x Reduction	Minimum Limit Achieved (lb/MMBtu)	Vendor Information: Fraction of Removal From Uncontrolled NO_x Emissions
Tangentially-fired			
LNC1 – Bituminous	42%	0.24	
LNC1 - Sub-bituminous/Lignite	56%	0.12 / 0.17	40 to 50%
LNC2 – Bituminous	47%	0.24	
LNC2 - Sub-bituminous/Lignite	61%	0.12 / 0.17	47 to 60%
LNC3 – Bituminous	62%	0.24	
LNC3 - Sub-bituminous/Lignite	71%	0.12 / 0.17	55 to 65%
Other Combustor Types			
Cell Burners - non plug in combustion controls	70%	None	
Cyclone – Coal Reburning	50%	None	36 to 52 %
Vertically-Fired	40%	None	

3.2 Advanced Low NO_x Technologies

Several control technologies are available to retrofit the existing units to achieve greater NO_x reduction. Many were discussed in Section 3.1 relative to the controls currently in place. In addition, there are later generations of these technologies and some state of the art technologies that can be used to improve NO_x reductions.

Table 3-3 lists the newest NO_x combustion controls that are commercially available. These newer technologies are being used on 122 installations in the U.S. The table also summarizes the range of emission reductions and or emission limits achieved using the technologies.

Table 3-3. Summary of NO_x Removal Performance of State of the Art Controls[a]

State of the Art Control	Number of Retrofit Commercial Installations	Baseline Control	NO_x Removal Efficiency (over baseline)	NO_x Emission Limit Achieved (lb/MMtu)
Replacements to Baseline NO_x Control				
Vortex LNB	International: 1			0.21
DRB-4Z burner	US: 12	1st generation LNB	28 - 48%	0.16 - 0.3
DRB-4Z burner		2nd generation LNB and OFA	10 – 25%	
CCV Dual Air Zone	US: 16 International: 1	1st generation LNB	26 - 46%	0.15 - 0.41
CCV Dual Air Zone		Uncontrolled	59 – 74%	
CCV Cell Burner	US: 8	Uncontrolled	52 - 64%	0.40 - 0.70
TFS 2000 R	US: 22	Uncontrolled	51 - 69%	0.12 - 0.22
ROFA	US: 17	Uncontrolled	33 - 64%	0.21 - 0.29
Micronized Reburn		Uncontrolled	57%	0.39
Additions to Baseline NO_x Control				
ROFA	US: 17	LNB	33 - 64%	0.21 - 0.29
ECT and CADM	15	LNC3	8 - 20%	
Neural Networks	Unknown but significant number	LNB, CCOFA and SOFA	10 - 15%	
O2 Enhanced Combustion:	US: 1	LNB and OFA	20 -60%	0.18

[a] Sources of vendor data are from References 6-29.

Table 3-4 shows the EGUs with various combustor configurations and fuels burned using the newer technologies. A detailed summary of information gathered on these technologies is presented in Appendix A.

Table 3-4. Summary of Combustor Configurations and Fuel Types in State of the Art NO_x Combustion Control Retrofit Installations

	Combustor				Fuel Category				
	Wall-fired	Tangential-fired	Cell	Cyclone	PRB	Eastern Bit.	Mid-Western Bit.	Western Bit.	Other Bit.
Advanced LNB									
DRB-4Z	✔				✔		✔		
Vortex Series	✔								✔
CCV Dual Air Zone	✔				✔	✔			
CCV Cell Burner			✔			✔	✔		
Coal and Air Flow Monitors									
ECT/CADM		✔			✔		✔		
Neural Networks					✔	✔	✔		
Other State of the Art Combustion Controls									
TFS 2000 R		✔			✔	✔	✔		
ROFA	✔	✔				✔			
OEC	✔						✔		
Micronized Reburn				✔		✔			

Although the commercial installation of advanced low NO_x combustion systems on western fuels other than PRB is limited at this time, vendors of Low NO_x equipment have run tests on the performance of future combustion controls on western bituminous, PRB, and lignite coals. A paper presented in the fall of 2004 by Alstom indicated that proprietary prediction methodologies based on the physical parameters of the combustor and the thermal conditions resulting from firing eastern and mid-western coals have been updated using laboratory and empirical data from western fuels. The testing of these predictive methodologies performed on the western bituminous coals indicates that they would react similar to the Midwestern bituminous or the high volatile Eastern bituminous.[10]

Another concern surrounding the installation of combustion modification technologies to coal-fired units in the WRAP is the triggering of a PSD requirement either by increased emissions of carbon monoxide or increases in the annual capacity factor of the plant. CO emission limits were not provided in either of the source databases. During the utility survey discussed in Chapter 2, one utility mentioned this PSD requirement as a major concern. For utilities that have concerns regarding CO limits and NO_x performance, investigation of whether controls could be considered pollution control projects under PSD may be successful or the use of NO_x control technology options that do not increase CO emissions.

Table 3-5 provides costs for the traditional and newer NO_x controls. Cost information for the more traditional controls are given from a CAMD analysis in 2004 dollars and from vendor estimates. Cost information for the newer technologies was gathered solely from vendor quotes and vendor published reports. The vendor quotes are typically on the lower end of the costs incurred by the facility because most are only associated with fabrication and installation. A facility may have additional engineering and site preparation costs.

Table 3-5. Summary Capital Cost Information for NO_x Controls[a]

Unit Type/NO_x Combustion Controls	CAMD Analysis 2004$ Capital Cost ($/kW)	Vendor Information 2004$ Capital Cost ($/kW)
Dry Bottom OFA	6.17	8.8
Dry Bottom Wall-fired- LNB	19.56	5 to 10
Dry Bottom Wall-fired - LNBO – Bituminous	26.55	18.8
Tangentially-fired – LNC1 – Bituminous	10.31	4 to 6
Tangentially-fired – LNC2 – Bituminous	14.40	10 to 15
Tangentially-fired – LNC3 – Bituminous	16.45	12 to 18
Cell Burners - non plug in combustion controls	26.55	
Cyclone - Coal Reburning	82.33	81.69
Wet Bottom - NO_x Combustion Controls	11.18	

Table 3-5. Summary Capital Cost Information for NO_x Controls[a] (Continued)

Unit Type/NO_x Combustion Controls	CAMD Analysis 2004$ Capital Cost ($/kW)	Vendor Information 2004$ Capital Cost ($/kW)
Vertically Fired	12.58	
Coal-fired – SCR	113.31	
DRB-4Z Burner		6-11
Dual AirZone CCV® Burner		No costs available
Vortex Series Split Frame Low NO_x Burner		No costs available
Enhanced Monitoring for Wall-fired Units		No costs available
TFS 2000R		13-19
Enhanced TLN Systems		$200,000/installation
ROFA		17-25
Oxygen Enhanced Combustion		20-30

[a] Sources of vendor data are from References 6-28.

Details of the performance of the newest NO_x combustion controls are discussed below.

3.2.1 *Cyclone Furnaces-Reburn*

The major combustion control for cyclone furnaces is coal reburn. This technique divides the furnace into multiple combustion zones. A primary zone receives the majority of the fuel input but a portion of the fuel, approximately 25 percent, is sent to reburning combustion zone that does not contain enough oxygen for complete combustion. The NO_x reacts with the oxygen deficient zone to create elemental nitrogen. In order to complete the combustion process, a third combustion zone is used to rebalance the combustion air and fuel. CAMD estimates the installed capital cost of this technology to be $82.33 per kilowatt. Similar costs for coal reburning were listed in the 2003 Clean Coal Technology Programs Project Fact Sheet.[13]

NO_x removal efficiencies for coal reburning technology have achieved up to 50 percent removal according to both the CAMD analysis and the Clean Coal Technology Program.[5, 13] However, no commercial installations of coal reburn on cyclone furnaces have been identified.

3.2.2 *Next Generation Low-NO_x Burners*

Advanced Low-NO_x burners, also known as ultra low NO_x burners (ULNBs) are available to fit the needs of different combustor types. Advanced burner designs were identified for wall-fired, opposed wall-fired and cell-burner units. Advanced burners for tangential units were combined with separated over-fire air (SOFA) and in-windbox or closed coupled over-fire air (CCOFA) and are discussed in the next section.

(1) DRB-4Z Burner [14, 15]

The DRB-4Z burner developed by Babcock and Wilcox applies to dry bottom wall-fired and opposed wall-fired units. The burner has a third "transitional" air zone which results in better fuel air mixing and larger NO_x reductions than burners with single or dual air zones. As of 2001, 455 DRB-4Z burners had been installed on 12 different units. This burner has been demonstrated on a wide variety of coals, including western PRB coal and Illinois bituminous coal.

When the DRB-4Z is used in conjunction with OFA, the average emission levels achieved were reported to be:

PRB coal: 0.18 lb NO_x/MMBtu; 50 to 100 ppm CO; 0.3 percent unburned carbon
Mid-western Bituminous coal: 0.3 lb NO_x/MMBtu

Babcock and Wilcox developed a presentation tracking the evolution of burners of the last three decades and compared the NO_x removal efficiencies to the performance of the DRB-4Z. For units firing bituminous coal with a first generation LNB and over fire air, a switch to a DRB-4Z burner averaged a 28 percent reduction in NO_x emissions. Comparatively, a unit firing bituminous coal with a second generation LNB, such as a DRB-XCL, achieved an 11 percent reduction in NO_x emissions when switching to a DRB-4Z model burner.
The cost listed in a recent Babcock and Wilcox technical presentation ranged from $5 to $11 per kilowatt for design and engineering costs.

(2a) Dual Air Zone CCV® Burner [16, 17]

The dual air zone Controlled Combustion Venturi (CCV®) burners were developed by Babcock Power, and they can be applied to wall-fired (both front and opposed) and cell burners. The dual air zone enhancement to the CCV® burner for wall-fired units adds a tertiary air flow streams low swirl coal spreaders and flame stabilizer rings. As of the fall of 2004, there are 16 CCV® Dual Air Zone commercial retrofits in the U.S.

The Dual Air Zone CCV® Burner is reported to achieve the following emission limits:

PRB coal in conjunction with OFA: 0.155 lb NO_x/MMBtu; 40 ppm
Eastern Bituminous without OFA: 0.36 lb NO_x/MMBtu; 30-40 ppm CO

When Dual Air Zone CCV® retrofits replace earlier generation low NO_x burners, the vendor installation data showed a reduction of 26 to 46 percent in NO_x emissions. Furthermore, when the retrofit is made to a unit with no NO_x controls in place, NO_x emissions have been reduced between 59 and 72 percent.

No cost information was available for installations, however this burner is considered to be competitive with the DRB-4Z burner mentioned above.

(2b) Dual Air Zone CCV® Cell Burner [17]

The industry recognizes cell burners to be the most difficult to achieve substantial NO_x reduction with LNB control only. This reduction has been achieved on 8 separate commercial retrofits since 1998 using CCV® cell burner technology. Retrofits of this burner type have occurred on units without any existing low NO_x burner system in place. Installation data demonstrates NO_x reductions of 57 percent. No cost information was available.

The CCV® cell burner is reported to achieve the following emission limits:

Eastern Bituminous: 0.43 lb NO_x/MMBtu; 6 ppm CO

(3) Vortex Series Split Frame Low NO_x Burner[18]

The Vortex series split frame LNB developed by Foster Wheeler uses an axial swirl burner to mix fuel and air and is designed for wall-fired units. A split low NO_x coal nozzle generates both a fuel rich and fuel lean zone and removes the need for flame stabilizers. It is suited for small burner spaces because it does not require high windbox air pressure requirements. Given the early stages of this burner, performance data was only available for a single installation in Taiwan.

The Vortex series is reported to achieve NO_x emissions of 0.21 lb/MMBtu when used on a bituminous coal with a Fixed Carbon to Volatile Matter (FC/VM) ratio of 2.0. This FC/VM ratio is higher compared to the ratios of 1.0 to 1.44 reported in the WRAP utility survey. No cost information was available.

3.2.3 *Enhanced Monitoring for Wall-fired Units* [13, 19]

Several vendors of neural networks for utility boilers provide enhanced coal and air flow monitoring to which can result in marginal reductions in NO_x emissions. These systems measure and model multiple operating parameters and use this information to adjust to variations in fuel quality, equipment performance, and environmental conditions. Some examples of these neural networks include the Generic NO_x Control Intelligent System (GNOCIS), developed by EPRI and the NeuSIGHT developed by Pegasus Technologies. At least 35 installations of GNOCIS have been identified, and Pegasus has many more, however, the total number of installations of neural networks with enhanced monitoring could not be identified. The CAMD and EIA databases typically do not account for them because they do not require upgrades in NO_x combustion control hardware. However, enhanced monitoring has been in use for a number of years and it is expected that many units do utilize some form of it to optimize performance.

These neural network technologies have been demonstrated on a wide range of coal types, and on units ranging from 70 to 1350 MW in size. NO_x reductions are achieved while number maintaining or improving heat rate and reductions of 10 to 15 percent have been found in addition to the reductions from LNBs, close-coupled OFA or separated OFA, CCOFA and SOFA reported to achieve an additional 10 to15 percent reduction in NO_x emissions on a unit with an existing LNB and AOFA control.

3.2.4 *Ultra Low-NO_x Control via Low NO_x firing and SOFA/CCOFA*

(1) TFS 2000R [8, 20]

The TFS 2000R low NO_x control system developed by Alstom applies to tangential-fired units. This technology is the next step in the sequence of LNC1, LNC2, and LNC3 controls, and is designated as ULNC4 for this analysis. This control system stages air through coal nozzle tips, SOFA, and CCOFA. Additionally this control filters the fineness of the pulverized coal particles entering the combustor with a rotating classifier vane. A concentric air firing system creates an oxidizing environment for the coal near the furnace waterwalls to further improve combustion and reduce NO_x formation. The 2004 installation list provided by Alstom indicated 22 commercial retrofits of the TFS 2000 R system on pulverized coal tangentially-fired units. These installations have NO_x reduction potentials of 51 to 69 percent compared to uncontrolled values.

The TFS2000R is reported to achieve the following NO_x emission rates:

PRB coal: 0.15 lb NO_x /MMBtu
Eastern Bituminous coal (low volatility): 0.22 lb NO_x /MMBtu
Mid-Western Bituminous coal (high volatility): 0.18 lb NO_x/MMBtu

The installed capital costs for the TFS 2000R system range from $13 to $19/kW.

(2) Enhanced TLN Systems [21]

An enhancement to the Foster Wheeler TLN3 system, which is included in the LNC3 control category, consists of coal and air flow monitoring and control devices. The electric charge transfer (ECT) is a coal flow distribution and velocity device, and the compartment air distribution monitoring system (CADM) further reduce NO_x emissions. The ECT and CADM systems are estimated to get an 8 to 20 percent additional NO_x reduction compared to a TLN3 system without this monitoring system. To date, the ECT system has been installed on 15 power plants.

The enhanced TLN3/ECT/CADM system is reported to achieve the following emission rates:

PRB coal: 0.11 lb NO_x/MMBtu; 5 ppm CO;
50/50 Blend PRB and Western Bituminous coal: 0.16 lb NO_x/MMBtu

The estimated capital costs of the ECT and CADM systems are $200,000 for each of these two installations.

3.2.5 *ROFA* [23, 24, 25]

Mobotec has developed and installed a Rotating Opposed Fire Air (ROFA) combustion control. ROFA installations have occurred on single and twin furnace tangentially fired units, fluidized bed, wall-fired, vertically fired, and grate furnaces. Mobotec has performed computational fluid dynamic modeling on PRB, western and mid-western bituminous, sub-bituminous and lignite coal with the results indicating that ROFA will work on these coals. Project proposals have been submitted for lignite and North Dakota western bituminous coal. Currently, 17 commercial retrofit installations of ROFA systems have occurred on units ranging from 44 to 570 MW firing eastern bituminous coal. However, Mobotec has extrapolated performances of up to 1200 MW for the ROFA system.

ROFA is reported to achieve the following emission rates:

Tangentially-fired units: Average 0.25 lb NO_x/MMBtu; 12-20 ppm CO
Wall-fired units: Average 0.27 lb NO_x/MMBtu

The installation list provided by Mobotec indicates that additional NO_x reductions between 33 and 59 percent were achieved when a ROFA system was added to a unit with an LNB previously installed. NO_x reductions between 39 and 63 percent were achieved when a ROFA system was installed on units without existing NO_x controls.

The installed capital costs of the ROFA system, provided by Mobotec, range from $17 to $25 per kilowatt.

3.2.6 *Oxygen Enhanced Combustion* [26, 27, 28]

Oxygen enhanced combustion (OEC) is a technique developed by Praxair. This technique works by replacing a small portion (5 to 10 percent) of the combustion air in the primary combustion zone of specified burners with oxygen. The result is more comprehensive staged combustion, fuel rich conditions and increased flame temperature which all work together to reduce the formation of NO_x. Oxygen-enhanced combustion is especially beneficial in instances where air-staging is limited because of short residence time in small furnaces. Additionally the installations for oxygen enhanced combustion require minimal furnace downtime and modifications.

The current focus of this combustion control is on small to mid-sized wall-fired units. Praxair provides a guideline for effectiveness of this control to a size range of 15 – 300 MW. To date there is data on one pilot project installation and one full-scale project. Proposals have been submitted for this unit to operate on cyclone-fired units. Praxair stated that the NO_x removal performance in terms of percent reduction stays constant for the four different types of bituminous coal this technology has been tested on.

When installed on a wall-fired unit with an existing low NO_x burner and OFA system, OEC was reported to achieve 20 to 60 percent additional reductions in NO_x emissions when compared to the NO_x emission rates post-low NO_x burner with OFA. A NO_x emission rate of

0.18 lb/MMBtu was achieved on the first commercial application on a 125 MW wall-fired unit.

Praxair provided installed capital costs of $20 to $30 per kilowatt and NO_x removal costs of $1,800 to $2,500 per ton removed.

4.0 METHODOLOGY

NO_x formation and the selection of combustion controls to reduce emissions are dependent on a number of unit specific variables, particularly information on fuel burned and combustor design and operation. As discussed in Section 2.0, some unit specific information was gathered from existing EPA and DOE databases. However, the information in these databases did not provide adequate detail on parameters such as nitrogen in the fuel burned, residence time and volume, and combustor heat release rate. It also did not provide information on CO limits that might be applicable, and which might be a limiting factor in selecting control technologies to reduce NO_x.

An effort was made to collect more detailed unit specific information from telephone surveys. However, this information was only available for 20 percent of the units in the WRAP region, and was considered inappropriate to extrapolate to the remaining units. Additionally many of the combustor-specific data were considered proprietary and were not released from vendors to the utilities surveyed. State regulations and available facility permits were also reviewed to identify any CO limitations on the EGU's, but insufficient information was obtained. Consequently, the analysis was based on more general information for boilers, such as size, combustor type, fuel burned, and NO_x emissions.

Section 3.0 indicates that a number of NO_x combustion controls may be used to reduce emissions. Some of the controls are only applicable to, or more effective on, a specific type of combustor. Consequently, EGU's were subcategorized into similar sources, or bins, in order to select the most appropriate NO_x combustion controls to be analyzed.

4.1 EGU Bins

As indicated in Sections 2.0 and 3.0, cell burners, cyclone burners, CFB's, tangential burners, and wall-fired burners each have unique design configurations and applicable controls that may be used to reduce NO_x. Additionally, Section 2.0 indicates there are differences in the distribution and use of the burners (e.g., there are only 3 CFB's versus 44 tangentially-fired units) and in emissions between many of these burners on a per unit basis, e.g., cyclone and cell burners have higher emissions than wall-fired units on a per megawatt basis**.** Therefore, bins were developed for each burner type in the WRAP region.

Additional bins were added based on the type of coal burned. There is a clear difference in NO_x emissions from wall-fired units burning low nitrogen coal, such as powder river basin, and units firing higher nitrogen coal. Consequently, bins were created to show this distinction. For this analysis it was assumed that EGU's in Wyoming, not identified as firing a specific coal, would burn PRB coal due to the proximity of PRB mines in Wyoming. Based on NO_x emission rates comparisons of sub-bituminous coals from the same combustor type, units at Comanche, Escalante, and Pawnee plants were assigned to the lower nitrogen sub-bituminous category. Based on our information collected from certain utilities, Arapahoe was also assigned to this lower nitrogen sub-bituminous category.

Bins were also considered based on the location and size of EGU's in the WRAP region. However, most applicable controls, NO_x emission rates, and NO_x limits or reductions achieved are not limited by these factors. Therefore, no additional bins were added. Table 4-1 lists the 6 different bins and the number of EGU's in the WRAP that were assigned to each bin. Information on the combustor type for six units was not known. Therefore, they were not included in any of the bins.

Table 4-1. Bins Developed for EGU's in WRAP

Bin Designation	Bin Description	Number of EGU's Assigned to Bin[a]
1a	Tangentially-fired burners, high nitrogen	27
1b	Tangentially-fired burners, low nitrogen	17
2	Wall-fired burners, high nitrogen coal	33
3	Wall-fired burners, low nitrogen coal	12
4	Cyclone burners	5
5	Cell burners	3
6	CFB units	2
7	Dry bottom vertically fired	4

[a] Seven of the 110 units in WRAP are not included in our bin assignments or options analysis due to insufficient information provided for these 7 units.

4.2 Control Options

Combustion controls presented in Section 3.0 were used to identify potential control options. Coal reburn was the only combustion control option identified for cyclone burners. However, this technology has not been identified on any commercial institution. Therefore, while it is a potential control the likelihood of its use is in question. Only one control option was identified for cell burners, low NO_x burners specific to cell burners.

Currently, no control options were identified for existing CFB units due to the inherent nature of the burners (combustion takes place throughout the bed instead of in a confined zone making it difficult to apply a combustion control). However, NO_x emissions are also generally lower from CFB's because the bed temperature is lower than the peak temperatures associated with conventional pulverized coal burners.

Similar types of combustion controls may be used on tangential and wall-fired units. Differences occur in the specific controls that are applied to each type of combustor. For example, LNB's or OFA may be used on both tangential and wall-fired units. For tangential units, close-coupled or separated overfire air is used. For wall-fired units advanced overfire air is currently used as a retrofit option. The differences become more acute when newer state of the art combustion controls are considered.

For this study, separate control options were developed for wall-fired and tangential units based on the information presented in Section 3.0. Seven options were identified for wall-fired units and five options were developed for tangential units to account for the increasing emission reductions from going from existing controls to newer technologies. The initial options represent NO_x controls that are already in place on some western units. As the option number increases there is a transition into more state of the art technologies which have been commercially demonstrated in the U.S., although, often not on western fuels with the exception of PRB. The micronized reburn option for cyclone burners is the only option presented where there has been no long term commercial applications. Tables 4-2 through 4-5 summarizes the control options chosen for each EGU bin the expected percent emissions reductions and the lowest expected emissions rate for each option.

Table 4-2. Control Options Applied to Bin 1a

Baseline Controls	Number of Units	NO_x Control Applied at the Option	Removal Efficiency from Baseline Assumed (%)	Lowest Achievable Rate (lb/MMBtu)
Option 1				
None	5	None		
OFA – 1st generation	7	None		
LNC1	3	Upgrade to LNC3	20	0.24
LNC1 - post 1997	4	Upgrade to LNC3	20	0.24
LNC3	2	None		
LNC3 - post 1997	3	None		
Other	3	None		
Option 2				
None	5	LNC2	47	0.24
OFA – 1st generation	7	LNC2	47	0.24
LNC1	3	Upgrade to LNC3	20	0.24
LNC1 - post 1997	4	Upgrade to LNC3	20	0.24
LNC3	2	None		
LNC3 - post 1997	3	None		
Other	3	LNC2	47	0.24
Option 3				
None	5	LNC3	62	0.24
OFA – 1st generation	7	LNC3	62	0.24
LNC1	3	LNC3	62	0.24
LNC1 - post 1997	4	LNC3	62	0.24
LNC3	2	LNC3	62	0.24
LNC3 - post 1997	3	LNC3	62	0.24
Other	3	LNC3	62	0.24
Option 4				
None	5	ROFA	60	0.21
OFA – 1st generation	7	ROFA	60	0.21
LNC1	3	ROFA	59	0.21
LNC1 - post 1997	4	ROFA	59	0.21
LNC3	2	ROFA	59	0.21
LNC3 - post 1997	3	ROFA	59	0.21
Other	3	ROFA	60	0.21

Table 4-2. Control Options Applied to Bin 1a (Continued)

Baseline Controls	Number of Units	NO_x Control Applied at the Option	Removal Efficiency from Baseline Assumed (%)	Lowest Achievable Rate (lb/MMBtu)
Option 5				
None	5	ULNC4	52	0.18
OFA – 1st generation	7	ULNC4	65	0.18
LNC1	3	ULNC4	52	0.18
LNC1 - post 1997	4	ULNC4	52	0.18
LNC3	2	ULNC4	15	0.18
LNC3 - post 1997	3	ULNC4	15	0.18
Other	3	ULNC4	52	0.18

[a] Removal efficiencies for OFA are shown from uncontrolled because data was not available to estimate a reduction efficiency for OFA.

Table 4-3. Control Options Applied to Bin 1b

Baseline Controls	Number of Units	NO_x Control Applied at the Option	Removal Efficiency from Baseline Assumed (%)	Lowest Achievable Rate (lb/MMBtu)
Option 1				
None	4	LNC2	61	0.12
AOFA – post 1997	1	None		
LNB – old technology	3	None		
LNC1	4	None		
LNC1 – post 1997	1	None		
LNC2 – post 1997	2	None		
LNC3 – post 1997	2	None		
Option 2				
None	4	LNC2	61	0.12
AOFA – post 1997	1	None		
LNB – old technology	3	None		
LNC1	4	Upgrade to LNC3	15	0.12 or 0.17
LNC1 – post 1997	1	Upgrade to LNC3	15	0.12 or 0.17
LNC2 – post 1997	2	Upgrade to LNC3	15	
LNC3 – post 1997	2	None		
Option 3				
None	4	LNC3	71	0.12 or 0.17
AOFA – post 1997	1	LNC3	71	0.12 or 0.17
LNB – old technology	3	LNC3	71	0.12 or 0.17
LNC1	4	LNC3	71	0.12 or 0.17
LNC1 – post 1997	1	LNC3	71	0.12 or 0.17
LNC2 – post 1997	2	LNC3	71	0.12 or 0.17
LNC3 – post 1997	2	LNC3	71	0.12 or 0.17
Option 4				
None	4	ROFA	60	0.12 or 0.17
AOFA – post 1997	1	ROFA	60	0.12 or 0.17
LNB – old technology	3	ROFA	59	0.12 or 0.17
LNC1	4	ROFA	59	0.12 or 0.17
LNC1 – post 1997	1	ROFA	59	0.12 or 0.17
LNC2 – post 1997	2	ROFA	59	0.12 or 0.17
LNC3 – post 1997	2	ROFA	59	0.12 or 0.17
Option 5				
None	4	ULNCA4	65	0.11 or 0.17
AOFA – post 1997	1	ULNCA4	65	0.11 or 0.17
LNB – old technology	3	ULNCA4	65	0.11 or 0.17
LNC1	4	ULNCA4	65	0.11 or 0.17
LNC1 – post 1997	1	ULNCA4	65	0.11 or 0.17
LNC2 – post 1997	2	ULNCA4	65	0.11 or 0.17
LNC3 – post 1997	2	ULNCA4	15	0.11 or 0.17

[a] Removal efficiencies for OFA are shown from uncontrolled because data was not available to estimate a reduction efficiency for OFA.

[b] Bin 1b has both lignite and sub-bituminous coals 0.12 is the lowest achievable rate for sub-bituminous while 0.17 is the lowest rate for lignite.

Table 4-4. Control Options Applied to Bin 2

Baseline Controls	Number of Units	NO_x Control Applied at the Option	Removal Efficiency from Baseline Assumed (%)	Lowest Achievable Rate (lb/MMBtu)
Option 1				
None	1	None		
OFA – 2nd generation[a]	4	None		
LNB -1st generation	6	AOFA	15	0.32
LNB – 2nd generation	7	AOFA	15	0.32
LNB – post 1997	4	AOFA	15	0.32
LNBO – 1st generation	2	None		
LNBO – 2nd generation	6	None		
LNBO-post 1997	3	None		
Option 2				
None	1	LNB-post 1997	57	0.32
OFA – 2nd generation[a]	4	LNB-post 1997	57	0.32
LNB -1st generation	6	AOFA	15	0.32
LNB – 2nd generation	7	AOFA	15	0.32
LNB – post 1997	4	AOFA	15	0.32
LNBO – 1st generation	2	None		
LNBO – 2nd generation	6	None		
LNBO-post 1997	3	None		
Option 3				
None	1	AOFA	24	0.32
OFA – 2nd generation[a]	4	None		
LNB -1st generation	6	AOFA	22	0.32
LNB – 2nd generation	7	AOFA	22	0.32
LNB – post 1997	4	AOFA	22	0.27
LNBO – 1st generation	2	Upgrade AOFA	22	0.32
LNBO – 2nd generation	6	None		
LNBO-post 1997	3	None		
Option 4				
None	1	ULNB	62.5	0.32
OFA – 2nd generation[a]	4	ULNB	62.5[b]	0.27
LNB -1st generation	6	ULNB	33	0.32
LNB – 2nd generation	7	ULNB	11	0.32
LNB – post 1997	4	None		
LNBO – 1st generation	2	ULNB	33	0.27
LNBO – 2nd generation	6	ULNB	11	0.27
LNBO-post 1997	3	None		
Option 5				
None	1	ULNBO	68	0.27
OFA – 2nd generation[a]	4	ULNBO	68[b]	0.27
LNB -1st generation	6	ULNBO	33	0.27
LNB – 2nd generation	7	ULNBO	32	0.27
LNB – post 1997	4	AOFA	22	0.27
LNBO – 1st generation	2	ULNBO	33	0.27
LNBO – 2nd generation	6	ULNBO	11	0.27
LNBO-post 1997	3	None		

Table 4-4. Control Options Applied to Bin 2 (Continued)

Baseline Controls	Number of Units	NO_x Control Applied at the Option	Removal Efficiency from Baseline Assumed (%)	Lowest Achievable Rate (lb/MMBtu)
Option 6				
None	1	ULNBO	68	0.27
OFA – 2nd generation[a]	4	ULNBO	68[a]	0.27
LNB -1st generation	6	ULNBO	33	0.27
LNB – 2nd generation	7	ULNBO	32	0.27
LNB – post 1997	4	AOFA	22	0.27
LNBO – 1st generation	2	OEC	44	0.18
LNBO – 2nd generation				
Less than 300 MW	2	OEC	44	0.18
Greater than 300 MW	4	ULNBO	11	0.27
LNBO-post 1997				
Less than 300 MW	1	OEC	44	0.18
Greater than 300 MW	2	None		
Option 7				
None	1	ROFA	45	0.25
OFA – 2nd generation	4	ROFA	45	0.25
LNB -1st generation	6	ROFA	45	0.21
LNB – 2nd generation	7	ROFA	45	0.21
LNB – post 1997	4	ROFA	45	0.21
LNBO – 1st generation	2	ROFA	45	0.21
LNBO – 2nd generation	6	ROFA	45	0.21
LNBO-post 1997	3	ROFA	45	0.21

[a] Second generation OFA is the same technology as the advanced OFA (AOFA).

[b] Removal efficiencies for OFA are shown from uncontrolled because data was not available to estimate a reduction efficiency for OFA.

Table 4-5. Control Options Applied to Bin 3

Baseline Controls	Number of Units	NO_x Control Applied at the Option	Removal Efficiency from Baseline Assumed (%)	Lowest Achievable Rate (lb/MMBtu)
Option 1				
None	3	None		
OFA – 1st generation	1	None		
LNB -1st generation	3	AOFA	15	0.32
LNB – 2nd generation	1	AOFA	15	0.32
LNB – post 1997	1	AOFA	15	0.32
LNBO – 2nd generation	1	None		
LNBO-post 1997	1	None		
SCR – post 1997	1	None		
Option 2				
None	3	LNB-post 1997	15	0.18
OFA – 1st generation	1	LNB-post 1997	15	0.18
LNB -1st generation	3	AOFA	15	0.32
LNB – 2nd generation	1	AOFA	15	0.32
LNB – post 1997	1	AOFA	15	0.32
LNBO – 2nd generation	1	None		
LNBO-post 1997	1	None		
SCR – post 1997	1	None		
Option 3				
None	3	AOFA	24	0.18
OFA – 1st generation	1	Upgrade to AOFA	24	0.18
LNB -1st generation	3	AOFA	22	0.18
LNB – 2nd generation	1	AOFA	22	0.18
LNB – post 1997	1	AOFA	22	0.18
LNBO – 2nd generation	1	None		
LNBO-post 1997	1	None		
SCR – post 1997	1	None		
Option 4				
None	3	ULNB	62.5	0.18
OFA – 1st generation	1	ULNB	62.5	0.18
LNB -1st generation	3	ULNB	48	0.18
LNB – 2nd generation	1	ULNB	25	0.18
LNB – post 1997	1	None		
LNBO – 2nd generation	1	ULNB	25	0.158
LNBO-post 1997	1	None		
SCR – post 1997	1	None		
Option 5				
None	3	ULNBO	68	0.158
OFA – 1st generation	1	ULNBO	68	0.158
LNB -1st generation	3	Upgrade to ULNBO	33	0.158
LNB – 2nd generation	1	Upgrade to ULNBO	32	0.158
LNB – post 1997	1	AOFA	22	0.158
LNBO – 2nd generation	1	Upgrade to ULNBO	33	0.158
LNBO-post 1997	1	None		
SCR-post 1997	1	None		

Table 4-5. Control Options Applied to Bin 3 (Continued)

Baseline Controls	Number of Units	NO_x Control Applied at the Option	Removal Efficiency from Baseline Assumed (%)	Lowest Achievable Rate (lb/MMBtu)
Option 6				
None	3	ROFA	68	0.158
OFA – 1st generation	1	ROFA	45	0.25
LNB -1st generation	3	ROFA	45	0.21
LNB – 2nd generation	1	ROFA	45	0.21
LNB – post 1997	1	ROFA	45	0.21
LNBO – 2nd generation	1	ROFA	45	0.21
LNBO-post 1997	1	ROFA	45	0.21
SCR-post 1997	1	None		

[a] Removal efficiencies for OFA are shown from uncontrolled because data was not available to estimate a reduction efficiency for OFA.

Table 4-6. Control Options Applied to Bin 4, 5, 6 and 7

Baseline Controls	Number of Units	NO_x Control Applied at the Option	Removal Efficiency from Baseline Assumed (%)	Lowest Achievable Rate (lb/MMBtu)
Bin 4 Option 1				
None	4	Coal reburning	50	
OFA –post 1997	1	Coal reburning	50	
Bin 4 Option 2				
None	4	Micronized Reburning	57	
OFA – post 1997	1	Micronized Reburning	57	
Bin 5 Option 1				
None	1	ULNCB	60	
LNCB – post 1985	2	ULNCB	60	
Bin 5 Option 2				
None	1	ULNB	64	0.18
LNCB – post 1985	2	ULNB	64	0.396
Bin 6				
No options				
Bin 7 Option 1				
None	1	LNB	68	0.12
LNBO – 2nd generation	1	None		
LNBO-post 1997	1	None		
OFA-post 1997	1	LNB	68	0.32

[a] Removal efficiencies for OFA are shown from uncontrolled because data was not available to estimate a reduction efficiency for OFA.

4.3 Calculation of the Impacts

This section presents the methodology used to calculate emission reductions and costs for control options applied to each EGU bin, and the results of the analysis. Costs and emission reductions of each option for each EGU are presented in Appendix C.

Costs and emission reductions were calculated based on information presented in Section 3.0. The cost and emission reductions for each control option reflects the change from the baseline level of control to the control technology required in the option. If an EGU already had the same or more effective control as the option, then no costs or emission reductions were calculated for the EGU for that option.

The effectiveness of the control depended not only on the category of the control device, but also the generation of a given control category. Given that the installation dates of different NO_x control technologies in the WRAP ranged from the late 1970s to the late 1990s, the relative performance of an existing NO_x combustion control device to a retrofitted control option was deemed to be sensitive to its date of installation. As a result of this relationship, all controls were assigned to one of three generation categories listed in Table 4-7.

Table 4-7. Assumptions on the Generation of Existing Low NO_x Equipment

Equipment	Date of Installation	Generation
None	--	--
LNB, OFA, LNBO	1970s or 1980s	1st
LNC1, LNC3, LNB, LNBO, AOFA[a], Other, LNCB	1990s or no date provided and CAMD assumed pre-1997	2nd
AOFA[a], LNB, LNBO, LNC2, LNC3, LNCB,	post 1997	State of the art

[a] Although AOFA installed since 1990s is listed in CAMD as OFA, we assume this to be equivalent to AOFA, defined as a fan-boosted OFA. This assumption is based on information from Foster Wheeler that the term AOFA has been interchanged with OFA in the last decade due to the fact that this is the only remaining over-fire air option currently installed on wall-fired units. No progressions in the NO_x removal efficiency of AOFA is expected to have occurred since the second generation OFA.

As assumed in the CAMD analysis, it was assumed in this analysis that 1997 is the point in which controls can be considered to be the best available renditions of a control category. This cut-off date is based of the date of the second phase of the Acid Rain Program. Additionally vendor data for state of the art technologies, such as the ULNB CCV Dual Air Zone burner started being installed in 1998. Therefore, when selecting what units to apply state of the art options, it was assumed that a LNB installed since 1997 is as effective as the state of the art ULNB option, and thus no costs or emission reductions are calculated.

Another variable for calculating emissions for a control option was the baseline NO_x emission level. The database of WRAP EGUs includes emission data from two primary sources. The first is the 2001 to 2003 NO_x emission data collected from a CEMs. The second data source is a pre-control NO_x value from a 1996 report for the phase two Acid Rain Program. This pre-control value is not from real emission data at the EGU, but instead it was calculated by a curve fit developed by CAMD to estimate what emissions would be if a unit with an existing NO_x control did not have NO_x control. Although this pre-control rate is not real emission data, this value is the parameter for calculating the removal efficiencies of LNC2 and LNC3 controls. As a result, this analysis uses pre-control values on units with existing controls in place where the pre-control value is not less than the 2003 emission data. Sometimes vendors provided removal efficiencies in comparison to uncontrolled values, and so this pre-control rate is used to estimate removal efficiencies from the appropriate baselines. In all other instances, the CEMs data is the baseline for emission reduction calculations. When a comparison can be made between existing baseline controls and a control option, the CEMs data is a much more accurate baseline for three major reasons. First, in some instances these pre-control values are less than existing CEMs emission data for 2003. This occurs due to some errors in the curve fit. Secondly, units with no listed controls have pre-control NO_x emission values that are much larger than the current emission data for 2003 without NO_x controls we assume that the actual 2003 emissions reflect a more accurate baseline. Finally, the pre-control values were calculated in 1996 and since then some units could have switched from a western bituminous to a PRB coal. These pre-control would reflect a pre-controlled rate for the wrong type of fuel. A detailed table presenting when the pre-control rates versus the actual CEMs emissions data were used for each bin and each option is shown in Appendix C.

4.3.1 *Cost Calculations*

Table 4-7 summarizes the information, as introduced in Section 3.0, used to calculate installed capital and annual costs of each NO_x combustion control. Costs for technologies that are currently used on EGU's in the WRAP region (e.g., LNB's) were taken from the CAMD study and updated to 2004 dollars. If more current information on the technology was provided by vendors, then the more current information was incorporated. For example, current LNB capital costs provided by vendors indicated that LNB's were less expensive then the CAMD estimates. Consequently the newer cost information was used as the lower bound for the costs of a LNB.

Cost information for newer technologies and state of the art controls was limited to a range or a single point for installed capital costs on a $/kW basis. This information was obtained from vendors or technical literature and the cost estimates included caveats regarding the economies of scale for larger units. The capital costs selected are not adjusted for variations in unit size. At this time data are not available to fit a cost curve as a function of unit size. As a result the costs used in this analysis probably over estimate the actual installed capital costs on larger units. Additionally, asbestos removal costs are not included in these estimates. One vendor provided the caveat to their cost estimates as a rough guideline and did not recommend their data to be used as a criterion for justifying/eliminating any options with respect to a compliance plan.[8,9,12] The information supplied by the other vendors is expected to be of the same accuracy. However, these costs have been incorporated in the options analysis because no additional information is available.

The total installed capital costs of control options for each EGU in the WRAP were calculated based on nameplate capacities using the equation below:

*Installed Capital Cost ($/kW) = Nameplate Capacity (MW) * Cost of control ($/kW) * 1000 (kW/MW) * Scaling Factor for Capital*

Where a range of costs were provided, the calculation was done for the maximum, minimum, and average values. Summary tables in this section are based on using the average values or the single cost value provided by the vendor.

Total annual cost estimates were calculated from three components: annualized capital, fixed operation and maintenance (O&M) costs, and variable O&M costs. The largest portion of the annualized costs for combustion controls is the annualized capital costs.
The annualized capital cost was calculated using a capital recovery factor of equal to current interest rate over the life of the combustion control. Vendors indicated that most equipment has an estimated life of 15 years. The interest rate used for this analysis is 7.7 percent resulting in a capital recovery factor of 0.115. A capital recovery factor of 12 percent was used for the analysis of control options in the CAMD analysis. No O&M costs were available for newer technologies and state of the art controls. Therefore, these controls were

assumed to have similar fixed and variable O&M costs as the closest related control from the CAMD control options analysis. Variable O&M costs ranged from 0.03 mills/kw-yr to 0.29 mills/kw-yr depending on the control option. Fixed O&M costs ranged from 0.21 $/kw-yr to 1.25 $/kw-yr depending on the control option. The variable and fixed O&M factors and associated scaling factors for state of the art controls were estimated by transferring the values from a similar control in the CAMD analysis or taking an average of several factors. The exact variable and fixed O&M factors used for each control option are shown in Table 4-8. More detailed cost information is presented in Appendix C.

Table 4-8. Installed Cost Factors ($2004)

NO_x Control Action	Avg. or Single Value TCI ($/kW)	Variable O&M - mills/kW-hr	Fixed O&M $/kW
LNC2	14.4	0.03	
Upgrade to LNC3	16.45 - 10.31	0.03 - 0.0	0.25 - 0.16
LNC3	16.45	0.03	0.25
ROFA	21	0.02	0.21
ULNC4	30	0.02	0.21
LNB	19.56	0.06	0.29
ULNB	10.5	0.06	0.29
AOFA (assuming CAMD curve-fits)	26.55-19.56	0.08 – 0.06	0.41 - 0.29
AOFA (assuming vendor data)	8.8	0.08 - 0.06	0.41 - 0.29
ULNBO	15	0.08	0.41
OEC	25	0.14	0.35
Coal Reburning	82.33	0.29	1.25
Micronized Reburn	81.69	0.29	1.25
Non-plug-in Combustion Controls for Cell Burners	26.55	0.08	0.4
ULNCB	10.82	0.06	0.29
LNB for Vertically Fired	19.56	0.06	0.29
SCR	113	0.68	0.75

4.3.2 *Emission Reductions*

The emission reductions for a given option compare the NO_x emission limit calculated by the control removal efficiencies to a floor rate for a NO_x emission limit. This floor rate represents the minimum NO_x rate achievable using a given control, and it is based either on data from vendors installation lists or technical literature when available. The rates are specific to the performance of a control when used on a certain fuel and combustor type that matches a bin. This floor rate was used in the analysis to ensure that the rated removal efficiencies of certain controls achieve realistic NO_x emission rates. For example, if a unit is currently operating at 0.32 lb NO_x/MMBtu and the average NO_x removal efficiency of the ULNB option on bituminous coal is 62.5 percent, the resulting NO_x emission factor would be 0.128 lb/MMBtu. Given that vendor data only demonstrates an emission rate of 0.27, the performance of the ULNB in this analysis was set at the demonstrated emission limit instead of using the less realistic value of 0.128 calculated by the percent reduction. By the same token, a unit operating at 0.85 lb NO_x/MMBtu and a retrofit of a ULNB is expected to achieve 62.5 percent reduction, or 0.32 lb NO_x/MMBtu. The expected emission reductions are the 0.32 value and do not automatically assume the reductions will reach the floor.

When floor rates from vendors could not be identified, the default floor rates from the CAMD analysis were used with a small adjustment. CAMD used floor rates specific to sub-bituminous (0.12 lb/MMBtu), lignite (0.17 lb/MMBtu), and bituminous coals (0.24 lb/MMBtu). This analysis includes these floor rates specific to the same three categories, however the sub-bituminous floor of 0.12 lb/MMBtu applies only to PRB or other low nitrogen content western sub-bituminous coals. An additional floor rate of 0.24 lb/MMBtu was assigned as the default value for units firing other types of sub-bituminous coals. This assumption is based on that a PRB sub-bituminous coal has a much lower nitrogen content than other western sub-bituminous coal.

More detail of the specific removal efficiencies for each option of each bin are located in Appendix D.

5.0 RESULTS

Table 5-1 summarizes the cost and emission reductions for control options applied to each EGU bin. Table 5-2 summarizes the results by State.

These tables also compare the costs and emission reductions of the control options to the costs and emission reductions that would be achieved if EGU's were required to meet the BART emission level (0.20 lb/MMBtu) using an SCR. The comparison was made using SCR because it is the most likely add-on technology that would be used to meet the BART level. SCR costs were calculated using the 2004 update to EPA's Integrated Model Planning for utilities. However, some EGU's may achieve the BART level using SNCR instead. The table shows the costs and emission reductions for only those EGU's that are known to be subject to BART, and units who are likely to be subject to BART.

In order to compare the total cost and emission impacts across all bins to the cost and emission impacts of an SCR option for all BART-eligible units, three overall scenarios were created to represent a variety of options from the different bins. The first scenario selects the option from each bin that achieves the greatest amount of emission reductions while using only NO_x controls that are used on other EGUs in the WRAP or have had several successful commercial demonstrations on a wide variety of coals. The second scenario includes more state of the art NO_x controls that have not been demonstrated on as many units or different types of coals. The third scenario selects the option that achieves the greatest emission reduction from the bin. In some cases the same option for a bin is used in multiple scenarios because of its high performance or cost efficiency with respect to emission reductions. Table 5-3 indicates that scenarios 3 for all EGU's would achieve a similar emission reduction level to SCR applied to only the BART sources in the WRAP region. Appendix E summarizes the cost and emission reductions of each option for each EGU.

Table 5-1. Cost and Emission Reductions for Control Options Applied to Bins

Option	Average Capital Costs $millions	Average Total Annualized Costs $millions (CRF + Fixed +Variable)	Total Emission Reductions	Average $/ton Removed	% Emission Reduction[a]
Bin 1a					
Option 1	46	7	19,684	360	11%
Option 2	5	8	22,676	348	13%
Option 3	146	22	49,261	445	28%
Option 4	251	33	69,623	472	40%
Option 5	320	40	71,429	561	41%
SCR on Bart Yes Units	936	160	50,190	3,182	29%
SCR on Bart Yes and Maybe Units	1,168	199	63,129	3,153	36%
Bin 1b					
Option 1	11.30	1.70	7,495	227	9%
Option 2	1.24	1.90	7,786	244	9%
Option 3	84.11	12.70	43,843	290	52%
Option 4	110.68	14.71	43,763	336	52%
Option 5	126.87	16.03	36,227	442	43%
SCR on Bart Yes Units	428.62	75.97	26,820	2,833	32%
SCR on Bart Yes and Maybe Units	536.26	95.85	30,979	3,094	37%
Bin 2					
Option 1	26.66	4.36	11,990	364	7%
Option 2	50.13	8.28	18,780	441	11%
Option 3	44.93	6.59	17,578	375	10%
Option 4	83.60	11.72	27,513	426	16%
Option 5	120.29	21.69	41,277	526	24%
Option 6	134.32	24.09	44,770	538	26%
Option 7	205.36	27.21	71,610	380	42%
SCR on Bart Yes Units	550.55	95.47	46,212	2,066	27%
SCR on Bart Yes and Maybe Units	850.68	148.06	69,819	2,121	41%
Bin 3					
Option 1	12.60	2.07	3,426	603	8%
Option 2	27.48	4.61	6,327	728	15%
Option 3	25.51	3.73	7,807	477	18%
Option 4	19.27	4.76	12,383	385	29%
Option 5	53.72	9.77	14,813	660	34%
Option 6	62.94	8.44	18,649	453	43%
SCR on Bart Yes Units	318.34	57.98	9,784	5,926	23%
SCR on Bart Yes and Maybe Units	349.99	63.42	12,211	5,194	28%
Bin 4					
Option 1	115.35	19.20	27,439	700	44
Option 2	120.51	20.11	32279	623	51
SCR on Bart Yes Units	146.21	26.90	36,824	731	59
SCR on Bart Yes and Maybe Units	189.33	34.59	46,375	746	74

Table 5-1. Cost and Emission Reductions for Control Options Applied to Bins (Continued)

Option	Average Capital Costs $millions	Average Total Annualized Costs $millions (CRF + Fixed +Variable)	Total Emission Reductions	Average $/ton Removed	% Emission Reduction[a]
Bin 5					
Option 1	24.57	4.32	8,153	530	24
Option 2	17.70	2.74	7,716	355	23
SCR on Bart Yes Units (no maybe units)	211.72	35.46	20,697	1,714	62
Bin 6					
SCR on Bart Yes Units (no maybe units)	11.66	1.97	299	6,590	13
Bin 7					
Option 1 CAMD- LNB	6.24	0.92	2,601	352	36
No BART units					

[a] Percent emission reduction represents emissions reduced by an option divided by the total current emissions for the units in the bin.

Table 5-2. NO_x Control Scenario Results by State

	AZ	CO	MT	ND	NM	NV	OR	SD	UT	WA	WY
Scenario 1											
TCI 10^6 $	45	50	34	130	47	28	5.9	9.5	49	17	81
TAC10^6 $	6.6	7.3	5.2	21	7.2	4.2	0.81	1.5	7.1	2.7	12
Emission Reduction tpy	16,000	14,000	15,000	32,000	18,000	9,500	1,800	3,500	14,000	4,900	44,000
$ per ton removed	410	520	350	660	400	440	450	430	510	550	270
Number of Units Affected	11	20	6	10	10	7	1	1	10	2	17
Scenario 2											
TCI 10^6 $	150	58	73	120	57	69	8.4	30	91	44	91
TAC10^6 $	20	9.7	9.3	19	9.9	9.7	1.5	4.8	13	5.5	15
Emission Reduction tpy	36,000	17,000	19,000	36,000	18,000	16,000	1,800	5,300	25,000	3,000	46,000
$ per ton removed	560	570	490	530	550	610	83	910	520	1800	330
Num. of Units Affected	14	16	6	10	10	8	1	1	9	2	17
Scenario 3											
TCI 10^6 $	160	71	73	110	69	73	9.5	30	110	44	62
TAC10^6 $	20	25	9.3	28	9.9	9.3	1.3	4.8	14	5.5	50
Emission Reduction tpy	35,000	30,000	19,000	39,000	26,000	17,000	4,800	5,300	33,000	3,000	62,000
$ per ton removed	570	830	490	720	380	550	270	910	420	1800	810
Num. of Units Affected	14	18	6	10	10	8	1	1	10	2	15
SCR on BART Yes Units to 0.2 lb/MMBtu Limit											
TCI 10^6 $	430	370	96	210	380	230	--	45	140	160	540
TAC10^6 $	74	66	17	38	65	38	--	8	23	28	96
Emission Reduction tpy	25,000	19,000	6,000	27,000	39,000	13,000	--	12,000	8,900	7,100	34,000
$ per ton removed	3,000	3,500	2,800	1,400	1,700	2,900	--	670	2,600	4,000	2,900
Num. of Units Affected	9	13	3	7	8	5	0	1	3	2	13
SCR on BART Yes and Maybe Units to 0.2 lb/MMBtu Limit											
TCI 10^6 $	540	400	190	350	430	320	51	45	160	160	670
TAC10^6 $	94	71	33	64	74	53	9	8	28	28	28
Emission Reduction tpy	31,000	20,000	12,000	40,000	44,000	18,000	5,504	12,000	20,000	7,100	11,000
$ per ton removed	3,000	3,600	2,700	1,600	1,700	2,900	1,642	670	1,400	4,000	2,500
Num. of Units Affected	12	14	5	11	9	8	1	1	7	2	15

Table 5-3. Three Scenarios of Various NO_x Combustion Controls to Compare to an SCR BART-option

		Capital Costs $millions	Total Annualized Costs $millions	Total Emission Reductions	Average$/ton Removed	% Emission Reduction[a]
Scenario 1	Bin1a-remove and replace existing equipment with SOTA LNC3 Bin1b-remove and replace existing equipment with SOTA LNC3 Bin2-ULNB Bin3-ULNB Bin4-CAMD-coal reburning Bin5- ULNCB (dual air zone CCV) Bin 7- LNB for vertically-fired	470	74	170,000	440	30%
Scenario 2	Bin1a-ULNC4 Bin1b-remove and replace existing equipment with SOTA LNC3 Bin2-OEC and ULNBO Bin3-ULNBO Bin4-Micronized Reburning Bin5- ULNCB (dual air zone CCV) Bin 7- LNB for vertically-fired	740	110	220,000	500	38%
Scenario 3	Bin1a-ULNC4 Bin1b-remove and replace existing equipment with SOTA LNC3 Bin2-ROFA Bin3-ROFA Bin4-Micronized Reburning Bin5- ULNCB (dual air zone CCV) Bin 7- LNB for vertically-fired	820	110	250,000	440	43%
	SCR Totals	**3,300**	**580**	**240,000**	**2,400**	**42%**
	SCR Yes Only Totals	**2,600**	**450**	**190,000**	**2,400**	**33%**

[a] Percent emission reduction represents the overall emission reductions divided by the total current emissions for 103 coal-fired EGUs. Seven units which did not have enough data to perform the options impacts analysis (5 units in AK, 1 unit in CA, and 1 unit in ND) are not included.

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Appendix A – List of EGU's in WRAP States

ORIS Code	Plant Name	Plant State	Boiler ID	Bin ID	Nameplate Capacity (MW)	2003 Est. Actual Capacity (MW)	BoilerType	Pre Control Nox Emission Rate	Avg Pre-Control Nox Emission Rate	2001 Avg. NOx Rate (lb/mmBtu)	2002 Avg. NOx Rate (lb/mmBtu)	2003 Avg. NOx Rate (lb/mmBtu)	2001 to 2003 Avg. NOx Rate (lb/mmBtu)	Baseline Nox Control	Assumed Generation of Baseline NOx Control
Foot-note						1		5	5				2		
79	Aurora Energy LLC Chena	AK	1		5										
79	Aurora Energy LLC Chena	AK	2		5										
79	Aurora Energy LLC Chena	AK	3		5										
79	Aurora Energy LLC Chena	AK	5		20										
6288	Healy	AK	1		25										
10002	ACE Cogeneration Facility	CA					CFB								
2790	R M Heskett	ND	B1												
160	Apache Station	AZ	2	2	195	198	DTF	0.582		0.47	0.45	0.47	0.46		no listed control
160	Apache Station	AZ	3	2	195	187	DTF	0.576		0.44	0.42	0.44	0.43	OFA	no listed control
113	Cholla	AZ	1	1a	114	120	T	0.460		0.37	0.37	0.36	0.37		no listed control
113	Cholla	AZ	2	1a	289	402	T	0.416		0.34	0.32	0.33	0.33	OFA	1st
113	Cholla	AZ	3	1a	289	264	T	0.358		0.29	0.32	0.31	0.31	OFA	1st
113	Cholla	AZ	4	1a	414	278	T	0.377		0.27	0.29	0.32	0.29	OFA	1st
6177	Coronado	AZ	U1B	2	411	411	DTF	0.514		0.43	0.4	0.4	0.41	OFA	2nd
6177	Coronado	AZ	U2B	2	411	409	DTF	0.510		0.43	0.43	0.46	0.44	OFA	2nd
126	Irvington	AZ	4	2	173	96	DB	no data	0.713	0.42	0.44	0.43	0.43	LNBO	1st
4941	Navajo	AZ	1	1a	803	810	T	0.412		0.37	0.35	0.34	0.35	O	2nd
4941	Navajo	AZ	2	1a	803	758	T	0.414		0.36	0.35	0.36	0.36	O	2nd
4941	Navajo	AZ	3	1a	803	845	T	0.372		0.33	0.36	0.32	0.34	O	2nd
8223	Springerville	AZ	1	1a	425	391	T	0.340		0.41	0.41	0.37	0.40	LNC1	2nd
8223	Springerville	AZ	2	1a	425	416	T	0.334		0.41	0.39	0.4	0.40	LNC1	2nd
465	Arapahoe	CO	3	7	44	64	DVF	0.419		0.77	0.71	0.76	0.75		no listed control
465	Arapahoe	CO	4	7	100	127	DVF	1.100		0.26	0.23	0.26	0.25	LNBO	2nd
468	Cameo	CO	2	2	44	51	DB	0.956		0.38	0.39	0.36	0.38	LNBO	2nd
469	Cherokee	CO	1	7	100	123	DVF	1.381		0.31	0.32	0.31	0.31	LNBO	post-1997
469	Cherokee	CO	2	7	110	103	DVF	1.668	1.170	0.76	0.78	0.66	0.73	OFA	post-1997
469	Cherokee	CO	3	2	150	161	DB	0.730		0.33	0.32	0.32	0.32	LNBO	2nd
469	Cherokee	CO	4	1a	350	340	T	0.510		0.31	0.36	0.34	0.34	LNC3	2nd
470	Comanche	CO	1	1b	350	360	T	0.236		0.22	0.33	0.35	0.30		no listed control
470	Comanche	CO	2	3	350	377	DB	0.311		0.32	0.29	0.27	0.29	OFA	1st
6021	Craig	CO	C1	2	446	404	DB	0.391		0.36	0.37	0.36	0.36	LNBO	post-1997
6021	Craig	CO	C2	2	446	480	DB	0.401		0.37	0.39	0.4	0.39	LNB	1st
6021	Craig	CO	C3	2	446	438	DB	0.281		0.35	0.35	0.36	0.35	LNB	1st
525	Hayden	CO	H1	2	190	280	DB	0.894		0.43	0.44	0.43	0.43	LNBO	post-1997
525	Hayden	CO	H2	1a	257	221	T	0.448		0.36	0.36	0.33	0.35	LNC3	post-1997

ORIS Code	2001 Avg NOx Emissions (tpy)	2002 Avg NOx Emissions (tpy)	2003 Avg NOx Emissions (tpy)	2001 to 2003 Avg NOx Emissions (tpy)	2001 Avg Annual Heat Input (mmBtu/yr)	2002 Avg Annual Heat Input (mmBtu/yr)	2003 Avg Annual Heat Input (mmBtu/yr)	2001 to 2003 Avg Annual Heat Input (mmBtu/yr)	Coal Moisture (percent)	Coal Nitrogen (percent)	Combustor Volume (ft^3)	Volumetric Heat Release Rate (Btu/hr/ft^3)	Coal Residence Time (sec.)	Single or Twin Furnace	CO limit	State Source of Coal
Foot-note				2				2	3	3	3	3	3	3	3	4
79										0.85						
79										0.85						
79										0.85						
79										0.85						
6288																
10002																UT
2790																
160	3485.3	3398.7	3743.5	3,543	14653838	14869245	15609877	15,044,320	22.21	1.04	115,300	15,040	6	S	NA	
160	3548.2	2934.6	3492.1	3,325	16084206	13532210	15758612	15,125,009	22.21	1.04	115,300	15,040	6	S	NA	
113	1544.9	1857.3	1762.2	1,721	8255932	10135095	9979443	9,456,823								
113	3948.2	3374.9	3692.1	3,672	23208116	21208980	22876576	22,431,224								
113	3380.1	3393.3	1654.3	2,809	23501777	21469659	10497453	18,489,630								
113	4416.9	4255.4	5425.2	4,699	31783485	28625402	33342396	31,250,428								
6177	7151.4	5236.9	6666.8	6,352	33009137	25715203	33369745	30,698,028								
6177	7078.3	6695.8	7485.5	7,087	33071966	29885142	32155044	31,704,051								
126	1745.8	1742.9	1494.3	1,661	8229130	7895974	6893085	7,672,730	10.6	1.41	66,420	14,600	2	S	NA	
4941	10841.3	11630.8	10272.4	10,915	57297411	65147474	60405414	60,950,100								
4941	12356.2	11677.9	12686	12,240	68649158	66550066	69890459	68,363,228								
4941	10822.1	12260.1	8661.9	10,581	65692126	67701146	53182543	62,191,938								
8223	6993.1	6342.3	6234.4	6,523	33812952	30914349	33603251	32,776,851	13.94	0.91	313,760	11,663	NA	S	NA	
8223	6196.6	6229.2	6253.9	6,227	30226158	31961642	31492188	31,226,663	13.94	0.91	313,760	11,273	NA	S	NA	
465	1642	1772	1913.9	1,776	4196091	4890119	4994794	4,693,668	26.8	0.69						
465	924.4	1063	1202.7	1,063	7165699	9336381	9272490	8,591,523	26.8	0.69						
468	847.5	819.4	712.8	793	4433623	4239544	4003029	4,225,399	10.21	1.30						
469	1248	1459.3	1628.3	1,445	7810265	8970802	10293712	9,024,926	9.34	1.59						
469	3505.3	2472.4	2923	2,967	9122841	6203591	8484948	7,937,127	9.34	1.59						
469	1928.4	1558.2	2065.2	1,851	11622986	9797919	12748751	11,389,885	9.34	1.59						
469	3520	3985.6	3837.2	3,781	23056200	21731932	22186191	22,324,774	9.34	1.59						
470	2848.5	4773.1	4812.5	4,145	25515232	28241572	26958633	26,905,146	29.35	0.80						
470	3994.4	4036.5	4299.4	4,110	25196745	27300712	31594468	28,030,642	29.35	0.80						
6021	6893.6	6607.5	5776.9	6,426	38446056	35484467	31735443	35,221,989	15.94	1.36	350,000	12,200	2	S		CO
6021	6157.3	7428.1	7885	7,157	32727798	38077170	39043808	36,616,259	15.94	1.36	350,000	12,200	2	S		CO
6021	5873	5345.5	6003.5	5,741	33316600	30387915	33149377	32,284,631	15.94	1.36	350,000	12,200	2	S		CO
525	4134.5	4139.3	3341.2	3,872	19025081	18836045	15165062	17,675,396	12.92	1.34						
525	4047.4	4464	3909.8	4,140	22257367	24378569	23279310	23,305,082	12.92	1.34						

ORIS Code	Regulation for NOx	Standard for NOx	Unit for NOx standard	Year unit complied with NOx Std.	Inservice Date	Retirement Date	Primary Fuel (1)	Primary Fuel (2)	Primary Fuel (3)	Wet or Dry Bottom	Status of NOx control equipment	Low NOx process (1)	Low NOx process (2)	Low NOx process (3)	Manufacturer of Low NOx equipment	BOILER_MANUFACTURER	2003 Hours Under Load	BART Analysis ERG 041905
Foot-note	ST=State; FD=Federal LO=local										OP=operating	NA-not applicable; LN-Low NOx burner; OV-overfire air; OT-other; LA-low excess air; BF-biased firing						
79												NA					7823	M
79												NA					6431	M
79												NA					3012	M
79												NA					7871	Y
6288											OP	LN			FW		6783	Y
10002	LO	104	LBS/HR	1990	01-JUN-90		BIT	PC		D	OP	CF	OT		NA	PR	8017	N
2790			lb/mmBtu		01-NOV-54		LIG	WC		D		NA				RS	8448	M
160	ST	0.70	lb/mmBtu	1979	01-JAN-79		SUB	NG		D	OP	OV			NA	RS	8055	Y
160	ST	0.70	lb/mmBtu	1979	01-SEP-79		SUB	NG		D	OP	OV			NA	RS	8605	Y
113	FD	0.45	lb/mmBtu	1997	01-JUN-62		SUB			D		NA				CE	8517	Y
113	FD	0.70	lb/mmBtu	1980	01-JUN-78		SUB			D	OP	OV			NA	CE	8408	Y
113	FD	0.70	lb/mmBtu	1980	01-MAY-80		SUB			D	OP	OV			NA	CE	4064	M
113	FD	0.70	lb/mmBtu	1981	01-JUN-81		SUB			D	OP	OV			NA	CE	8455	M
6177	ST	0.70	lb/mmBtu	1979	01-DEC-79		SUB			D	OP	OV			NA	RS	8286	Y
6177	ST	0.70	lb/mmBtu	1980	01-OCT-80		SUB			D	OP	OV			NA	RS	8024	M
126	LO	0.70	lb/mmBtu	1988	01-MAY-67		BIT	SUB		D	OP	LN			FW	FW	7358	Y
4941	FD	0.45	lb/mmBtu	1997	01-MAY-74		BIT			D	OP	OT			NA	CE	7611	Y
4941	FD	0.45	lb/mmBtu	1997	01-APR-75		BIT			D	OP	OT			NA	CE	8443	Y
4941	FD	0.45	lb/mmBtu	1997	01-MAY-76		BIT			D	OP	OT			NA	CE	7164	Y
8223	ST	0.697	lb/mmBtu	1985	01-JUN-85		SUB			D	OP	LN			CE	CE	8240	N
8223	ST	0.697	lb/mmBtu	1990	01-JUN-90		SUB			D	OP	LN			CE	CE	8218	N
465	FD	0.80	lb/mmBtu	2000	01-JUN-51		SUB	NG	BIT	D		NA				BW	7993	N
465	ST	0.60	lb/mmBtu	2000	01-JUN-55		SUB	NG	BIT	D	OP	LN	OV		BW	BW	7457	N
468							BIT				OP	LN			BW		7967	N
469	ST	0.60	lb/mmBtu	2000	01-JUN-57		BIT	NG	SUB	D	OP	LN	OV		BW	BW	8558	N
469	FD	0.80	lb/mmBtu	2000	01-JUN-59		BIT	NG	SUB	D	OP	OV			NA	BW	8369	N
469	ST	0.60	lb/mmBtu	1997	01-JUN-62		BIT	NG	SUB	D	OP	LN	OV		FW	BW	8097	Y
469	ST	0.45	lb/mmBtu	1994	01-JUN-68		BIT	NG	SUB	D	OP	LN	OV		CE	CE	6668	Y
470	FD	0.45	lb/mmBtu	1997	01-JUN-73		SUB	NG		D		NA				CE	7634	Y
470	FD	0.50	lb/mmBtu	1997	01-JUN-75		SUB	NG		D	OP	OV			NA	BW	8548	Y
6021	FD	0.50	lb/mmBtu	1980	01-JUL-80	01-OCT-30	SUB			D	OP	LN			BW	BW	7388	Y
6021	FD	0.50	lb/mmBtu	1979	01-NOV-79	01-FEB-30	SUB			D	OP	LN			BW	BW	8299	Y
6021	FD	0.50	lb/mmBtu	1984	01-OCT-84	01-JAN-34	SUB			D	OP	LN			BW	BW	8383	N
525	FD	0.46	lb/mmBtu	2000	01-JUL-65		BIT	NG	DFO	D	OP	LN	OV		BW	RS	6987	Y
525	FD	0.40	lb/mmBtu	2000	01-SEP-76		BIT	DFO		D	OP	LN	OV		FW	CE	8490	Y

ORIS Code	Plant Name	Plant State	Boiler ID	Bin ID	Nameplate Capacity (MW)	2003 Est. Actual Capacity (MW)	BoilerType	Pre Control Nox Emission Rate	Avg Pre-Control Nox Emission Rate	2001 Avg. NOx Rate (lb/mmBtu)	2002 Avg. NOx Rate (lb/mmBtu)	2003 Avg. NOx Rate (lb/mmBtu)	2001 to 2003 Avg. NOx Rate (lb/mmBtu)	Baseline Nox Control	Assumed Generation of Baseline NOx Control
Foot-note						1		5	5				2		
492	Martin Drake	CO	5	2	59	144	DB	1.085	0.960	0.41	0.4	0.43	0.41	LNB	post-1997
492	Martin Drake	CO	6	2	88	89	DB	0.829	0.890	0.39	0.37	0.38	0.38	LNB	post-1997
492	Martin Drake	CO	7	2	147	46	DB	0.931	0.937	0.41	0.4	0.35	0.39	LNB	post-1997
527	Nucla	CO	1	6	113	117	CFB	0.17		0.27	0.29	0.34	0.30	O	
6248	Pawnee	CO	1	3	500	546	DB	0.623		0.23	0.23	0.23	0.23	LNBO	2nd
6761	Rawhide	CO	101	1a	285	319	T	0.434		0.33	0.33	0.34	0.33	LNC1	2nd
8219	Ray D Nixon	CO	1	2	230	225	DB	0.543		0.31	0.31	0.26	0.29	LNB	1st
477	Valmont	CO	5	1a	166	187	T	0.664		0.29	0.31	0.32	0.31	LNC3	2nd
6076	Colstrip	MT	1	1a	358	362	T	0.512		0.4	0.4	0.38	0.39	OFA	1st
6076	Colstrip	MT	2	1a	358	358	T	0.566		0.43	0.4	0.4	0.41	OFA	1st
6076	Colstrip	MT	3	1a	778	758	T	0.339		0.4	0.41	0.41	0.41	OFA	1st
6076	Colstrip	MT	4	1a	778	816	T	0.348		0.41	0.41	0.37	0.40	OFA	1st
2187	J E Corette Plant	MT	2	1b	191	182	T	0.650	0.495	0.24	0.26	0.29	0.26	OFA	post-1997
6089	Lewis & Clark	MT	B1	1b	50	59	T	0.569	0.780	0.37	0.36	0.37	0.37	LNC1	2nd
6469	Antelope Valley	ND	B1	1b	435	485	T	0.425		0.37	0.34	0.33	0.35	LNB	1st
6469	Antelope Valley	ND	B2	1b	435	481	T	0.273		0.31	0.3	0.35	0.32	LNB	1st
6030	Coal Creek	ND	1	1b	506	599	T	0.554		0.21	0.21	0.2	0.21	LNC3	post-1997
6030	Coal Creek	ND	2	1b	506	610	T	0.819		0.23	0.22	0.22	0.22	LNC3	post-1997
8222	Coyote	ND	B1	4	450	465	C	0.811		0.77	0.72	0.72	0.74		no listed control
2817	Leland Olds	ND	1	3	216	250	DB	0.742		0.26	0.27	0.29	0.27	LNB	2nd
2817	Leland Olds	ND	2	4	440	448	C	1.034		0.66	0.62	0.61	0.63		no listed control
2823	Milton R Young	ND	B1	4	257	482	C	0.811		0.78	0.79	0.82	0.80		no listed control
2823	Milton R Young	ND	B2	4	277	281	C	1.046		0.83	0.81	0.77	0.80		no listed control
2790	R M Heskett	ND	B2	6	75	86	CFB	0.286		0.3	0.31	0.29	0.30		
2824	Stanton	ND	1	3	187	61	DB	0.188		0.42	0.43	0.44	0.43	LNB	post-1997
2824	Stanton	ND	10	1b	60	132	T	0.188		0.36	0.35	0.34	0.35	LNC2	1st
87	Escalante	NM	1	1b	233	209	T	0.347		0.38	0.4	0.4	0.39	LNB	1st
2442	Four Corners	NM	1	2	190	182	DB	0.824		0.78	0.77	0.77	0.77	LNB	1st
2442	Four Corners	NM	2	2	190	241	DB	0.779		0.58	0.61	0.62	0.60	LNB	1st
2442	Four Corners	NM	3	2	253	703	DB	1.000		0.58	0.57	0.58	0.58	LNB	1st
2442	Four Corners	NM	4	5	818	723	CB	0.942		0.54	0.57	0.56	0.56	LNCB	2nd
2442	Four Corners	NM	5	5	818	182	CB	1.100		0.49	0.45	0.48	0.47	LNCB	2nd
2451	San Juan	NM	1	2	361	330	DB	0.420		0.43	0.42	0.41	0.42	LNBO	2nd
2451	San Juan	NM	2	2	350	308	DB	0.651		0.41	0.43	0.46	0.43	OFA	2nd
2451	San Juan	NM	3	2	534	465	DB	0.394		0.4	0.42	0.41	0.41	LNBO	2nd
2451	San Juan	NM	4	2	534	527	DB	0.423		0.42	0.43	0.41	0.42	LNBO	2nd
2341	Mohave	NV	1	1a	818	597	T	0.383		0.41	0.42	0.42	0.42		no listed control
2341	Mohave	NV	2	1a	818	661	T	0.458		0.36	0.39	0.35	0.37		no listed control

ORIS Code	2001 Avg NOx Emissions (tpy)	2002 Avg NOx Emissions (tpy)	2003 Avg NOx Emissions (tpy)	2001 to 2003 Avg NOx Emissions (tpy)	2001 Avg Annual Heat Input (mmBtu/yr)	2002 Avg Annual Heat Input (mmBtu/yr)	2003 Avg Annual Heat Input (mmBtu/yr)	2001 to 2003 Avg Annual Heat Input (mmBtu/yr)	Coal Moisture (percent)	Coal Nitrogen (percent)	Combustor Volume (ft^3)	Volumetric Heat Release Rate ($Btu/hr/ft^3$)	Coal Residence Time (sec.)	Single or Twin Furnace	CO limit	State Source of Coal
Foot-note				2				2	3	3	3	3	3	3	3	4
492	857.4	793.6	721.8	791	4114982	3915440	3366408	3,798,943								
492	1277.4	1414.7	1355.2	1,349	6568112	7651220	7176740	7,132,024								
492	2432.4	1996.7	2152	2,194	11789438	9967347	12130927	11,295,904								
527	1175	1332.6	1456.4	1,321	8487590	9001127	8224788	8,571,168								
6248	5845.4	4591.7	5369	5,269	51115319	38786012	45594820	45,165,384	30.39	0.70						
6761	4298.4	4007	4477.8	4,261	26060472	24284890	26351335	25,565,566								
8219	2681.7	2830.7	2411.3	2,641	17084122	18339257	18309946	17,911,108								
477	1986.7	2056.9	2476.5	2,173	13887790	13293779	15257755	14,146,441	12.80	1.08						
6076	5370	5811	4982.7	5,388	26939103	28955991	26328945	27,408,013								MT
6076	6338.8	4966.6	5773.4	5,693	29450518	24447384	28747740	27,548,547								MT
6076	11549.8	9097.6	12326.4	10,991	56870523	43256211	59466053	53,197,596								MT
6076	13862	12756.1	10769.3	12,462	67749767	61861103	56624427	62,078,432								MT
2187	1385.3	1702.9	2197.4	1,762	11315833	12979500	14800711	13,032,015								
6089	928.9	795.8	894.9	873	4899656	4303778	4793859	4,665,764								
6469	7696.8	5839.9	6473.2	6,670	40620251	34000916	39573116	38,064,761								
6469	5149.8	5953	7094.5	6,066	32269703	38848742	40418942	37,179,129								
6030	5482.6	4862.8	5197.2	5,181	51890721	46634656	51293286	49,939,554								
6030	5250.2	5491.6	5555.8	5,433	46107773	50610222	50638400	49,118,798								
8222	14259.1	13173.3	11737.3	13,057	36638274	36270124	32256357	35,054,918								
2817	2062.3	2580.7	3050.6	2,565	15704164	19239865	21058117	18,667,382								
2817	12717.8	11184.3	8813.3	10,905	37976687	35589576	28556587	34,040,950								
2823	9132.5	8509.9	8546.3	8,730	23194117	21434049	20513978	21,714,048								
2823	13449.6	14334.7	15145.6	14,310	31901487	35199244	38800281	35,300,337								
2790	943.2	918.1	952.7	938	6430421	6037325	6701989	6,389,912								
2824	2058.6	2209.2	2022.4	2,097	9800142	10380320	9146568	9,775,677								
2824	911.7	889.7	713.9	838	5018910	5035664	4067488	4,707,354								
87	3588.6	3469.8	3545.4	3,535	18549251	17152014	17822358	17,841,208	15.45	0.89	183,500	13,540	2	S		NM
2442	5986	5445.3	5712.3	5,715	14890648	13740129	14616287	14,415,688								
2442	4601.3	5204	4461.4	4,756	15513243	16632804	14138653	15,428,233								
2442	6409.7	5754	5142.6	5,769	21567144	19873582	17341579	19,594,102								
2442	16267.8	16502.8	16129.3	16,300	59728145	57787847	56712865	58,076,286								
2442	14034.8	8670.8	13750.9	12,152	56316988	37592636	56065980	49,991,868								
2451	6321.9	5209.7	5487.1	5,673	29192603	24550142	26246963	26,663,236								
2451	5165.4	5976	4832.2	5,325	24184320	27460582	20777976	24,140,959								
2451	8004	9404.3	7402.7	8,270	39080313	43742324	35256024	39,359,554								
2451	8923	9762.7	7781	8,822	41938627	45582346	37339667	41,620,213								
2341	10277.6	9926.5	10162.1	10,122	50043926	46715511	48035296	48,264,911								
2341	9151.9	10340.2	7974.2	9,155	50510546	52315381	45356270	49,394,066								

ORIS Code	Regulation for NOx	Standard for NOx	Unit for NOx standard	Year unit complied with NOx Std.	Inservice Date	Retirement Date	Primary Fuel (1)	Primary Fuel (2)	Primary Fuel (3)	Wet or Dry Bottom	Status of NOx control equipment	Low NOx process (1)	Low NOx process (2)	Low NOx process (3)	Manufacturer of Low NOx equipment	BOILER_MANUFACTURER	2003 Hours Under Load	BART Analysis ERG 041905
Foot-note	ST=State; FD=Federal LO=local										OP=operating	NA-not applicable; LN-Low NOx burner; OV-overfire air; OT-other; LA-low excess air; BF-biased firing						
492	FD	0.46	lb/mmBtu	2000	01-JUN-62		SUB	NG		D	OP	LN			BW	RS	7494	Y
492	FD	0.46	lb/mmBtu	2000	01-JUN-68		SUB	NG		D	OP	LN			BW	BW	8248	Y
492	FD	0.46	lb/mmBtu	2000	01-JUN-74		SUB	NG		D	OP	LN			BW	BW	8573	Y
527	FD	0.50	lb/mmBtu	1988	01-JAN-91	01-APR-37	BIT			D	OP	CF			NA	PR	7177	N
6248	FD	0.50	lb/mmBtu	1981	01-JUN-81		SUB	NG		D	OP	LN	OV		FW	FW	8522	Y
6761	FD	0.50	lb/mmBtu	1984	01-APR-84	01-DEC-19	SUB			D	OP	OV	LN		CE	CE	8427	N
8219	FD	0.50	lb/mmBtu	1996	01-APR-80		SUB			D	OP	LN			EA	BW	8293	M
477	ST	0.45	lb/mmBtu	1994	01-JUN-64		BIT	SUB	NG	D	OP	LN	OV		CE	CE	8312	Y
6076	FD	0.70	lb/mmBtu	1976	01-NOV-75	01-NOV-12	SUB			D	OP	LN			CE	CE	7431	Y
6076	FD	0.70	lb/mmBtu	1976	01-AUG-76	01-AUG-13	SUB			D		LN			CE	CE	8192	Y
6076	FD	0.70	lb/mmBtu	1984	01-JAN-84	01-JAN-21	SUB			D		OV			NA	CE	8009	Y
6076	FD	0.70	lb/mmBtu	1986	01-APR-86	01-APR-23	SUB			D		OV			NA	CE	7085	N
2187					01-JUL-68	01-JUN-25	SUB	NG		D	OP	OV			NA	CE	8296	Y
6089							LIG					NA					8243	M
6469	ST	0.50	lb/mmBtu	1983	01-JUL-84		LIG			D	OP	LN			CE	CE	8327	M
6469	ST	0.50	lb/mmBtu	1986	01-JUL-86		LIG			D	OP	LN			CE	CE	8566	N
6030	ST	5104.00	LBS/HR	1980	01-AUG-79		LIG			D	OP	OV	LN		FW	CE	8574	M
6030	ST	5104.00	LBS/HR	1981	01-JUL-81		LIG			D	OP	OV	LN		FW	CE	8621	M
8222	FD	0.86	lb/mmBtu	2000	01-MAY-81		LIG			W		NA				BW	7083	M
2817	FD	0.50	lb/mmBtu	1997	01-JAN-66		LIG	SUB		D	OP	LN			BW	BW	8580	Y
2817	FD	0.86	lb/mmBtu	2000	01-DEC-75		LIG	SUB		W		NA				BW	6506	Y
2823	FD	0.86	lb/mmBtu	2001	01-NOV-70	01-JAN-25	LIG			W		NA				BW	7459	Y
2823	FD	0.86	lb/mmBtu	2001	01-MAY-77	01-JAN-25	LIG			W		NA				BW	8214	Y
2790	ST	0.40	lb/mmBtu	1963	01-NOV-63		LIG	SUB	WC	D		NA				BW	7911	Y
2824	ST	0.46	lb/mmBtu	2000	01-MAY-67	01-JUN-27	LIG			D	OP	LN			AL	FW	7058	Y
2824	ST	0.60	lb/mmBtu	1982	01-JUN-82	01-JUN-27	LIG			D	OP	LN			CE	CE	6822	M
87	FD	0.45	lb/mmBtu	1985	01-DEC-84	01-DEC-30	SUB			D	OP	LN			CE	CE	8703	N
2442	ST	0.85	lb/mmBtu	1992	01-MAY-63		SUB			D	OP	LN			RS	RS	8192	Y
2442	ST	0.85	lb/mmBtu	1992	01-JUN-63		SUB			D	OP	LN			FW	RS	7919	Y
2442	ST	0.65	lb/mmBtu	1992	01-AUG-64		SUB			D	OP	LN			FW	FW	7339	Y
2442	ST	0.65	lb/mmBtu	1992	01-JUL-69		SUB			D	OP	LN			FW	BW	8233	Y
2442	ST	0.65	lb/mmBtu	1992	01-JUL-70		SUB			D	OP	LN			FW	BW	7911	Y
2451	ST	0.45	lb/mmBtu	1976	01-DEC-76	01-DEC-22	SUB			W	OP	LN			FW	FW	8128	Y
2451	ST	0.70	lb/mmBtu	1976	01-DEC-73	01-DEC-22	SUB			W	OP	LA			NA	FW	6893	Y
2451	ST	0.45	lb/mmBtu	1979	01-DEC-79	01-DEC-22	SUB			W	OP	LN			BW	BW	7732	Y
2451	ST	0.45	lb/mmBtu	1982	01-APR-82	01-DEC-22	SUB			W	OP	LN			BW	BW	7230	M
2341	FD	0.70	lb/mmBtu	1971	01-APR-71		SUB	NG		D		NA				CE	8213	Y
2341	FD	0.70	lb/mmBtu	1971	01-OCT-71		SUB	NG		D		NA				CE	7003	Y

ORIS Code	Plant Name	Plant State	Boiler ID	Bin ID	Nameplate Capacity (MW)	2003 Est. Actual Capacity (MW)	BoilerType	Pre Control Nox Emission Rate	Avg Pre-Control Nox Emission Rate	2001 Avg. NOx Rate (lb/mmBtu)	2002 Avg. NOx Rate (lb/mmBtu)	2003 Avg. NOx Rate (lb/mmBtu)	2001 to 2003 Avg. NOx Rate (lb/mmBtu)	Baseline Nox Control	Assumed Generation of Baseline NOx Control
Foot-note						1		5	5				2		
8224	North Valmy	NV	1	2	254	248	DB	0.513		0.34	0.29	0.33	0.32	LNB	2nd
8224	North Valmy	NV	2	2	267	293	DB	0.403		0.4	0.4	0.45	0.42	LNB	2nd
2324	Reid Gardner	NV	1	2	114	317	DB	1.118		0.42	0.47	0.45	0.45	LNB	2nd
2324	Reid Gardner	NV	2	2	114	125	DB	1.132		0.43	0.46	0.46	0.45	LNB	2nd
2324	Reid Gardner	NV	3	2	114	126	DB	0.526		0.44	0.45	0.36	0.42	LNB	2nd
2324	Reid Gardner	NV	4	2	270	143	DB	0.375	0.782	0.3	0.33	0.47	0.37	LNBO	1st
6106	Boardman	OR	1SG	2	560	624	DB	0.402		0.44	0.41	0.41	0.42	LNBO	2nd
6098	Big Stone	SD	1	4	475	494	C	1.29	1.150	0.84	0.83	0.81	0.83	OFA	post-1997
7790	Bonanza	UT	1-1	2	400	504	DB	0.423		0.33	0.3	0.35	0.33	LNB	post-1997
3644	Carbon	UT	1	1a	75	116	T	0.503		0.43	0.45	0.43	0.44		no listed control
3644	Carbon	UT	2	1a	114	72	T	0.579		0.43	0.45	0.43	0.44		no listed control
6165	Hunter	UT	1	1a	446	428	T	0.496	0.407	0.4	0.41	0.39	0.40	LNC1	post-1997
6165	Hunter	UT	2	1a	472	451	T	0.550	0.420	0.4	0.38	0.36	0.38	LNC1	post-1997
6165	Hunter	UT	3	2	496	431	DB	0.339		0.41	0.4	0.39	0.40	LNBO	post-1997
8069	Huntington	UT	1	1a	498	411	T	0.522	0.480	0.4	0.38	0.34	0.37	LNC1	post-1997
8069	Huntington	UT	2	1a	498	424	T	0.427	0.463	0.41	0.39	0.36	0.39	LNC1	post-1997
6481	Intermountain Power Project	UT	1SGA	2	820	944	DB	0.452		0.43	0.42	0.36	0.40	LNB	2nd
6481	Intermountain Power Project	UT	2SGA	2	820	893	DB	0.377		0.41	0.4	0.38	0.40	LNB	2nd
3845	Transalta Centralia Generation	WA	BW21	1a	730	807	T	0.403		0.36	0.31	0.3	0.32	LNC3	post-1997
3845	Transalta Centralia Generation	WA	BW22	1a	730	771	T	0.452		0.37	0.3	0.3	0.32	LNC3	post-1997
4158	Dave Johnston	WY	BW41	3	114	390	DB	0.484		0.44	0.47	0.45	0.45		no listed control
4158	Dave Johnston	WY	BW42	3	114	249	DB	0.541		0.43	0.45	0.44	0.44		no listed control
4158	Dave Johnston	WY	BW43	5	229	118	CB	0.71	0.590	0.52	0.5	0.51	0.51		no listed control
4158	Dave Johnston	WY	BW44	1b	360	113	T	0.551		0.34	0.36	0.4	0.37		no listed control
8066	Jim Bridger	WY	BW71	1b	578	503	T	0.633		0.39	0.38	0.38	0.38	LNC1	2nd
8066	Jim Bridger	WY	BW72	1b	578	531	T	0.511		0.35	0.36	0.38	0.36	LNC1	2nd
8066	Jim Bridger	WY	BW73	1b	578	519	T	0.422		0.36	0.36	0.37	0.36	LNC1	2nd
8066	Jim Bridger	WY	BW74	1b	561	546	T	0.408		0.38	0.38	0.4	0.39	LNC1	post-1997
6204	Laramie River Station	WY	1	3	570	605	DB	0.349		0.25	0.28	0.25	0.26	LNB	1st
6204	Laramie River Station	WY	2	3	550	598	DB	0.322		0.27	0.27	0.27	0.27	LNB	1st

ORIS Code	2001 Avg NOx Emissions (tpy)	2002 Avg NOx Emissions (tpy)	2003 Avg NOx Emissions (tpy)	2001 to 2003 Avg NOx Emissions (tpy)	2001 Avg Annual Heat Input (mmBtu/yr)	2002 Avg Annual Heat Input (mmBtu/yr)	2003 Avg Annual Heat Input (mmBtu/yr)	2001 to 2003 Avg Annual Heat Input (mmBtu/yr)	Coal Moisture (percent)	Coal Nitrogen (percent)	Combustor Volume (ft^3)	Volumetric Heat Release Rate ($Btu/hr/ft^3$)	Coal Residence Time (sec.)	Single or Twin Furnace	CO limit	State Source of Coal
Foot-note				2				2	3	3	3	3	3	3	3	4
8224	2526.8	2857.1	3327.3	2,904	14704513	19446705	19905097	18,018,772								
8224	4498.1	5013.7	3608.2	4,373	21832941	24499702	15600497	20,644,380								
2324	1653	2221.4	2312.5	2,062	7894057	9491928	10138697	9,174,894								
2324	1947.1	2504.2	2386.2	2,279	9031360	10841071	10162427	10,011,619								
2324	2216.3	2320.3	1665.2	2,067	9973357	10154345	9453692	9,860,465								
2324	3221.8	3688.7	5566.2	4,159	20697548	21802457	23226825	21,908,943								
6106	10768.1	8400.7	10080	9,750												
6098	16453.8	14953.6	15930	15,779	39136358	35753697	38925319	37,938,458								
7790	6983.1	6712.2	7334.1	7,010												
3644	1281.7	1377	1278.4	1,312	5868788	6123949	5831762	5,941,500								
3644	1843.8	2001	2086.9	1,977	8527964	8815680	9675434	9,006,359								
6165	4522.6	7447.3	7169.2	6,380	21839107	35692776	36586803	31,372,895								
6165	6749.6	5750.2	5776.5	6,092	32976628	29470715	32166350	31,537,898								
6165	6297.4	6661	6632.3	6,530	30228047	33100394	33659727	32,329,389								
8069	5828.5	6236.8	5767.5	5,944	28260974	32151776	33685018	31,365,923								
8069	6347	4946.3	6156	5,816	30434753	24999208	34266030	29,899,997								
6481	14159.3	15767.5	13195.8	14,374	65798301	74390803	71788552	70,659,219								
6481	16879.1	14488.4	13992.1	15,120	82058169	71648774	73643765	75,783,569								
3845	10673.2	7039.4	9515.4	9,076	58571199	45867853	64076293	56,171,782								WA/MT
3845	7571.1	8423.5	10970.7	8,988	40599606	55602804	63625892	53,276,101								WA/MT
4158	2259.7	2341.4	1993.7	2,198	10271470	9859291	8724168	9,618,310								
4158	2025.5	2298	2191.5	2,172	9389438	10052221	9988893	9,810,184								
4158	4834.3	5026.9	5057.3	4,973	18276800	19819756	19531122	19,209,226								
4158	4788.2	5352.5	5270.7	5,137	27903324	29081694	26078697	27,687,905								
8066	9389.8	7412.8	8494.5	8,432	47187558	38072583	43672815	42,977,652								
8066	7568.2	7358.5	7798.1	7,575	41886015	40285426	40525555	40,898,999								
8066	8344.9	8312.9	6851.5	7,836	45490755	45232244	35777266	42,166,755								
8066	8816.3	7559.3	8005.7	8,127	45271421	39383587	39425018	41,360,009								
6204	6040.1	6728.1	5614	6,127	48243920	48061878	44137502	46,814,433								
6204	5631.6	6686.9	6726.8	6,348	40954490	48607657	50111066	46,557,738								

ORIS Code	Regulation for NOx	Standard for NOx	Unit for NOx standard	Year unit complied with NOx Std.	Inservice Date	Retirement Date	Primary Fuel (1)	Primary Fuel (2)	Primary Fuel (3)	Wet or Dry Bottom	Status of NOx control equipment	Low NOx process (1)	Low NOx process (2)	Low NOx process (3)	Manufacturer of Low NOx equipment	BOILER_MANUFACTURER	2003 Hours Under Load	BART Analysis ERG 041905
Foot-note	ST=State; FD=Federal LO=local										OP=operating	NA-not applicable; LN-Low NOx burner; OV-overfire air; OT-other; LA-low excess air; BF-biased firing						
8224	ST	0.70	lb/mmBtu	1982	01-DEC-81		BIT	SUB		D	CN	LN			BW	BW	8184	M
8224	ST	0.50	lb/mmBtu	1985	01-JUL-85		BIT	SUB		D	OP	LN	BF	LA	FW	FW	5425	M
2324			lb/mmBtu		01-APR-65		BIT	LIG		D	OP	LN			FW	FW	8253	Y
2324			lb/mmBtu		01-JUL-68		BIT	LIG		D	OP	LN			FW	FW	7235	Y
2324	ST	0.70	lb/mmBtu	1976	01-JUL-76		BIT	LIG		D	OP	LN			FW	FW	7633	Y
2324	ST	0.60	lb/mmBtu	1983	01-JUL-83		BIT	LIG		D	OP	LN			FW	FW	7465	M
6106	ST	0.70	lb/mmBtu	1980	01-AUG-80	01-JUN-20	SUB	DFO		D	OP	LN	OV		FW	FW	7890	M
6098	FD	0.86	lb/mmBtu	2000	01-MAY-75		SUB			W	OP	OT			NA	BW	8038	Y
7790	FD	0.50	lb/mmBtu	1986	01-MAY-86		BIT			D	OP	LN			AB	FW	8380	N
3644	FD	0.45	lb/mmBtu	1988	01-NOV-54		BIT			D		NA				CE	8211	M
3644	FD	0.45	lb/mmBtu	1998	01-SEP-57		BIT			D		NA				CE	8498	M
6165	ST	0.45	lb/mmBtu	1988	01-JUN-78		BIT			D	OP	LN			CE	CE	8275	Y
6165	ST	0.45	lb/mmBtu	1988	01-JUN-80		BIT			D	OP	LN			CE	CE	7609	M
6165	ST	0.46	lb/mmBtu	1988	01-JUN-83		BIT			D	OP	LN			BW	BW	8016	M
8069	FD	0.45	lb/mmBtu	1988	01-JUN-77		BIT			D	OP	LN			CE	CE	8106	Y
8069	FD	0.40	lb/mmBtu	1988	01-JUL-74		BIT			D	OP	LN			CE	CE	8510	Y
6481	ST	0.461	lb/mmBtu	1986	01-JUN-86	01-JUL-16	BIT	SUB		D	OP	LN			BW	BW	7759	N
6481	ST	0.461	lb/mmBtu	1987	01-MAY-87	01-JUL-17	BIT	SUB		D	OP	LN			BW	BW	8415	N
3845	LO	0.30	lb/mmBtu	2003	01-DEC-72		SUB			D	OP	LN	OV		AL	CE	8484	Y
3845	LO	0.30	lb/mmBtu	2002	01-JUL-73		SUB			D	OP	LN	OV		AL	CE	8047	Y
4158	ST	0.50	lb/mmBtu	1988	01-FEB-59		SUB			D		NA				BW	7850	M
4158	ST	0.50	lb/mmBtu	1988	01-JAN-61		SUB			D		NA				BW	8636	M
4158	ST	0.68	lb/mmBtu	1988	01-DEC-64		SUB			D		NA				BW	7999	Y
4158	ST	0.40	lb/mmBtu	1988	01-JUL-72		SUB			D	OP	LA			NA	CE	6825	Y
8066	ST	0.45	lb/mmBtu	1998	01-NOV-74		SUB			D	OP	OV			NA	CE	8166	Y
8066	ST	0.45	lb/mmBtu	1988	01-DEC-75		SUB			D	OP	OV			NA	CE	7969	Y
8066	ST	0.45	lb/mmBtu	1988	01-SEP-76		SUB			D	OP	OV			NA	CE	6872	Y
8066	ST	0.70	lb/mmBtu	1979	01-NOV-79		SUB			D	OP	OV			NA	CE	7999	Y
6204	FD	0.50	lb/mmBtu	1997	01-JUL-80		SUB			D	OP	LN			BW	BW	7532	Y
6204	FD	0.50	lb/mmBtu	1997	01-JUL-81		SUB			D	OP	LN			BW	BW	8447	Y

ORIS Code	Plant Name	Plant State	Boiler ID	Bin ID	Nameplate Capacity (MW)	2003 Est. Actual Capacity (MW)	BoilerType	Pre Control Nox Emission Rate	Avg Pre-Control Nox Emission Rate	2001 Avg. NOx Rate (lb/mmBtu)	2002 Avg. NOx Rate (lb/mmBtu)	2003 Avg. NOx Rate (lb/mmBtu)	2001 to 2003 Avg. NOx Rate (lb/mmBtu)	Baseline Nox Control	Assumed Generation of Baseline NOx Control
Foot-note						1		5	5				2		
6204	Laramie River Station	WY	3	3	550	620	DB	0.423		0.25	0.27	0.28	0.27	LNB	1st
4162	Naughton	WY	1	1b	163	218	T	0.423		0.51	0.52	0.51	0.51		no listed control
4162	Naughton	WY	2	1b	218	173	T	0.546		0.51	0.53	0.53	0.52		no listed control
4162	Naughton	WY	3	1b	326	315	T	0.620	0.540	0.36	0.37	0.37	0.37	LNC2	post-1997
7504	Neil Simpson II	WY	2	3		105	DB	no data	0.28	0.16	0.17	0.17	0.17	LNBO	post-1997
55479	Wygen 1	WY	3	3		86	DB	no data	0.20			0.12	0.12	SCR	post-1997
6101	Wyodak	WY	BW91	3	362	411	DB	no data	0.323	0.25	0.26	0.27	0.26		no listed control

ORIS Code	2001 Avg NOx Emissions (tpy)	2002 Avg NOx Emissions (tpy)	2003 Avg NOx Emissions (tpy)	2001 to 2003 Avg NOx Emissions (tpy)	2001 Avg Annual Heat Input (mmBtu/yr)	2002 Avg Annual Heat Input (mmBtu/yr)	2003 Avg Annual Heat Input (mmBtu/yr)	2001 to 2003 Avg Annual Heat Input (mmBtu/yr)	Coal Moisture (percent)	Coal Nitrogen (percent)	Combustor Volume (ft^3)	Volumetric Heat Release Rate (Btu/hr/ft^3)	Coal Residence Time (sec.)	Single or Twin Furnace	CO limit	State Source of Coal
Foot-note				2				2	3	3	3	3	3	3	3	4
6204	6323.4	5544.7	7369	6,412	50975075	40466511	51855000	47,765,529								
4162	3694.8	3365.2	3721.2	3,594	14372706	12583677	14405088	13,787,157								
4162	4554.5	4306.5	4432.2	4,431	17799227	15835524	16214540	16,616,430								
4162	4594.5	5240.8	4033	4,623	24989045	28425577	21154476	24,856,366								
7504	784.3	785.8	752.6	774	9571577	9094729	8677672	9,114,659								
55479			383	383			6368132	6368132								
6101	4600.7	4696.6	4663	4,653	35964854	35685720	33961751	35,204,108								

ORIS Code	Regulation for NOx	Standard for NOx	Unit for NOx standard	Year unit complied with NOx Std.	Inservice Date	Retirement Date	Primary Fuel (1)	Primary Fuel (2)	Primary Fuel (3)	Wet or Dry Bottom	Status of NOx control equipment	Low NOx process (1)	Low NOx process (2)	Low NOx process (3)	Manufacturer of Low NOx equipment	BOILER_MANUFACTURER	2003 Hours Under Load	BART Analysis ERG 041905
Foot-note	ST=State; FD=Federal LO=local										OP=operating	NA-not applicable; LN-Low NOx burner; OV-overfire air; OT-other; LA-low excess air; BF-biased firing						
6204	FD	0.50	lb/mmBtu	1997	01-NOV-82		SUB			D	OP	LN			BW	BW	8531	Y
4162	FD	0.40	lb/mmBtu	1988	01-MAY-63		SUB			D		NA				CE	8488	Y
4162	FD	0.40	lb/mmBtu	1988	01-OCT-68		SUB			D		NA				CE	7577	Y
4162	FD	0.40	lb/mmBtu	1988	01-OCT-71		SUB			D	OP	LN			CE	CE	6852	Y
7504							SUB				OP	LN			BW		8441	N
55479							SUB				OP	LN	SR		BW		7531	N
6101	ST	0.50	lb/mmBtu	1988	01-SEP-78		SUB			D	OP	LN			BW	BW	8422	Y

Notes

1 2003 Estimated actual capacity was calculated from total mmBtu listed in 2003 CAMD dataset divided by the total hours under load from the 2003 EIA 767 form. 0.098 mmBtu/hr per kilowatt conversion was used to estimate size in MW.

2 Average for NOx rate, NOx tons, and heat input were calculated by taking the mean of the 2001, 2002, and 2003 CAMD values for each of these three parameters.

3 Information gathered from utility questionaires

4 Information gathered from EIA form 423, however coal mine information has participation gaps for reporting in this field. Inofmration also gathered from some utilities who were part of the questionnaire for coal and combustor information.

5 Data taken from CAMD spreadsheet from 1996 EPA contract report.

6.The first six units in the data base are coal-fired EGUs listed in the EIA 767 form but not in CAMD datasets

Appendix B – Summary of Telephone Survey Results

Utilities	Plant-Unit	Fuel		Combustor						
		Moisture %	Nitrogen (% as received)**	Volume (ft^3)	Heat Release Rate (Btu/hr/ ft^3)	Coal Residence Time (sec.)	Single or Twin Furnace	CO limit	Potential NOx Reductions Over Baseline	Potential NOx Limits with Stated Technology
Tristate G and T	Craig- C1	15.94	1.36	350,000	12,200	2	S			
	Craig- C2	15.94	1.36	350,000	12,200	2	S			
	Craig- C3	15.94	1.36	350,000	12,200	2	S			
	Escalante-1	15.45	0.89	183,500	13,540	2	S			
Arizona Elec. Power	Apache-2	22.21	1.04	115,300	15,040	6	S			
	Apache-3	22.21	1.04	115,300	15,040	6	S			
Southern California Edison	Mohave-1	52	0.55	416,000	20,000	1.1	S	1,364.5 TPY to not trigger PSD		
	Mohave-2	52	0.55	416,000	20,000	1.1	S	1,364.5 TPY to not trigger PSD		
Xcel	Arapahoe	26.8	0.69	41,900	13,900	2.65	S			
	Arapahoe	26.8	0.69	81,320	13,900	2.65	S			
	Cameo	10.21	1.3	30,000	16,250	2.27	S			
	Cherokee	9.34	1.59	238,000			T			
	Cherokee	9.34	1.59	91,320	16,030	2.3	T			
	Cherokee	9.34	1.59	79,160	14,300	2.57	T			
	Cherokee	9.34	1.59	79,160	14,300	2.57	T			
	Comanche	29.35	0.8	238,000			S			
	Comanche	29.35	0.8	268,000	13,400	2.75	S			
	Valmont	12.8	1.08				S			
	Hayden	12.92	1.34				T			
	Hayden	12.92	1.34	171,500			?			
	Pawnee	30.39	0.7	559,100			T			
Tucscon Electric Power	Irvington	9.6	1.51	66,420	14,600	2.3	S	none		
	Springerville 1	13.94	0.91	313,760	11,663	Vendor Considers	S	none		
	Springerville 2	13.94	0.91	313,760	11,273	Proprietary	S	none		
Arizona Public Service	NO REPLY RECEIVED									
Public Service of NM	NO REPLY RECEIVED									

Utilities	Plant-Unit	Fuel		Combustor						
		Moisture %	Nitrogen (% as received)**	Volume (ft^3)	Heat Release Rate (Btu/hr/ ft^3)	Coal Residence Time (sec.)	Single or Twin Furnace	CO limit	Potential NOx Reductions Over Baseline	Potential NOx Limits with Stated Technology
Pacificorp	Carbon	8.8	1.51	45,000	16,000	Vendor Considers Proprietary	S	none	28%	0.31 - LNB - LVL II
	Carbon	8.8	1.51	67,400	14,900	Vendor Considers Proprietary	S	none	28%	0.31 - LNB - LVL II
	Hunter	10	1.2	319,000	11,910	Vendor Considers Proprietary	S	none	33%	0.26 - LNB - SOFA
	Hunter	10	1.2	319,000	11,910	Vendor Considers Proprietary	S	none	28%	0.26 - LNB - SOFA
	Hunter	10	1.2	382,800	10,300	Vendor Considers Proprietary	S	none	23%	0.30 - LNB,OFA
	Huntington	9	1.4	319,000	12,100	Vendor Considers Proprietary	S	none	24%	0.26 - LNB - SOFA
	Huntington	9	1.4	319,000	12,100	Vendor Considers Proprietary	S	none	28%	0.26 - LNB - SOFA
	Dave Johnston	29.9	0.97	136,250	14,550	Vendor Considers Proprietary	S	none	39%	0.31 - LNB,OFA
	Dave Johnston	29.9	0.97	284,500	10,940	Vendor Considers Proprietary	S	none	58%	0.17 - LNB - SOFA
	Dave Johnston	29.9	0.97	81,930	11,400	Vendor Considers Proprietary	S	none	38%	0.28 - LNB + OFA
	Dave Johnston	29.9	0.97	81,930	11,400	Vendor Considers Proprietary	S	none	36%	0.28 - LNB + OFA
	Naughton	20.8	1.3	115,500	12,750	Vendor Considers Proprietary	S	none	49%	0.26 - LNB LVL II

Utilities	Plant-Unit	Fuel		Combustor						
		Moisture %	Nitrogen (% as received)**	Volume (ft^3)	Heat Release Rate (Btu/hr/ ft^3)	Coal Residence Time (sec.)	Single or Twin Furnace	CO limit	Potential NOx Reductions Over Baseline	Potential NOx Limits with Stated Technology
Pacificorp	Naughton	20.8	1.3	156,000	13,100	Vendor Considers Proprietary	S	none	51%	0.26 - LNB LVL II
	Naughton	21.1	1.3	235,000	13,000	Vendor Considers Proprietary	S	none	0%	0.37 - LNB LVL II
	Wyodak	30.9	0.91	293,280	11,300	Vendor Considers Proprietary	S	none	11%	0.24 - LNB +OFA
	Jim Bridger	18.2	1.4	437,900	11,120	Vendor Considers Proprietary	S	none	32%	0.26 - LNB - SOFA
	Jim Bridger	18.2	1.4	437,900	11,120	Vendor Considers Proprietary	S	none	32%	0.26 - LNB - SOFA
	Jim Bridger	18.2	1.4	437,900	11,120	Vendor Considers Proprietary	S	none	30%	0.26 - LNB - SOFA
	Jim Bridger	18.2	1.4	437,900	11,120	Vendor Considers Proprietary	S	none	35%	0.26 - LNB - SOFA
Deseret G&T	NO REPLY RECEIVED									
Intermountain Power Project	Intermountain Power Project 1SGA	8.39	1.33	not available	not available	not available	S	1390 lb/hr monthly average	0.33-0.37	
	Intermountain Power Project 2SGA	8.39	1.33	not available	not available	not available	S		0.33-0.37	
Portland GE	NO REPLY RECEIVED									

Appendix C – Summary of Cost and Scaling Factors for Control Options

NOx Control Action	TCI Scaling Factor	Min TCI ($/kW)	Max TCI ($/kW)	Curve Fit Value of Vendor Single Value TCI ($/kW)	Variable O&M Scaling Factor	Variable O&M - mills/kW-hr	Fixed O&M Scaling Factor	Fixed O&M $/kW	Note
									A
LNC2	(300/nameplate MW)^ 0.359			14.4		0.03	(300/nameplate MW)^ 0.359		B
upgrade to LNC3	(300/nameplate MW)^ 0.359			16.45 - 10.31		.03 - 0.0	(300/nameplate MW)^ 0.359	0.25 - 0.16	B,C
LNC3	(300/nameplate MW)^ 0.359			16.45		0.03	(300/nameplate MW)^ 0.359	0.25	B
ROFA	none	17	25			0.02	(300/nameplate MW)^ 0.359	0.21	D
ULNC4	none	24	36			0.02	(300/nameplate MW)^ 0.359	0.21	E
LNB	(300/nameplate MW)^ 0.359	5	11	19.56		0.06	(300/nameplate MW)^ 0.359	0.29	F
ULNB		6	15			0.06	(300/nameplate MW)^ 0.359	0.29	G
AOFA (assuming CAMD curve-fits)	(300/nameplate MW)^ 0.359			26.55-19.56		.08 - .06	(300/nameplate MW)^ 0.359	0.41 - 0.29	B,H
AOFA (assuming vendor data)	none			8.8		.08 - .06	(300/nameplate MW)^ 0.359	0.41 - 0.29	I
ULNBO	none	10	20			0.08	(300/nameplate MW)^ 0.359	0.41	J
OEC	none	20	30			0.14	(300/nameplate MW)^ 0.359	0.35	K
Coal reburning	(300/nameplate MW)^ 0.553			82.33	(300/nameplate MW)^0.553	0.29	(300/nameplate MW)^0.553	1.25	B
Micronized Reburn	none			81.69	(300/nameplate MW)^0.553	0.29	(300/nameplate MW)^0.553	1.25	L
Non-plug-in Combustion Controls for Cell burners	(300/nameplate MW)^ 0.315			26.55	(300/nameplate MW)^0.553	0.08	(300/nameplate MW)^0.553	0.4	B
ULNCB	none			10.82	none	0.06	(300/G2) ^0.315	0.29	M
LNB for Vertically Fired	(300/nameplate MW)^0.553			19.56	(300/nameplate MW)^0.553	0.06	(300/nameplate MW)^0.553	0.29	N
SCR	(242/nameplate MW)^0.27			113	(242/Nameplate MW)^0.11	0.68	(242/nameplate MW)^0.27	0.75	O

Notes	
A	All CAMD costs were adjusted from $1999 dollars to $2004 dollars, vendor costs were given in current year dollars.
B	Costs source is CAMD
C	The subtraction represents the incremental costs of creating a LNC3 system by improving upon an existing LNC1 system. Since an LNC1 already has the CCOFA component of a LNC3 only the costs associated with adding the SOFA component of the LNC3 are analyzed here.
D	The costs for ROFA were given in three different size ranges and applied accordingly to the WRAP units: $17/kW for units between 500 and 1000 MW; $20/kW for units between 200 and 500 MW and $25/kW for units between 50 and 200 MW. The fixed and variable factors are assumed to be an average of the factors for an LNC1 and LNC3
E	The costs for a ULNC4 were given by Alstom and represent the costs for a 200 MW unit.
F	The minimum capital investment costs for a LNB are represented by the upper bound of the 5-11 $/kW value given from Foster Wheeler data on its CF/SF burner and a NOx combustion control report by MPR associates. These costs do not use the scaling factor that is applied to the maximum capital investment costs which represent the curve-fit cost data from CAMD.
G	There costs for a SOTA ULNB reflect the costs of a DRB-4z burner based on Babcock and Wilcox data for units ranging between 530 MW and 675 MW firing both sub-bituminous and bituminous coals.
H	The subtraction represents the incremental costs between a LNB and a LNBO system based on the CAMD cost source.
I	The costs for the SOTA AOFA was given by Foster Wheeler and it is representative of an installation on a 500 MW unit in Georgia. The variable and fixed rates are assumed to be the same as the AOFA option for CAMD, an incremental difference between a LNBO and LNB.
J	The costs for the SOTA AOFA and ULNBO was given by Foster Wheeler and it is representative of an installation on a 500 MW unit in Georgia. The fixed and variable costs were assumed to be the same as the CAMD LNBO.
K	Costs for OEC were provided by Praxair.
L	Costs for Micronized reburn are based on a single test at the Kodak facility in New York. This information was provided by the Clean Coal Technology Program.
M	Costs represent the performance of the dual air zone CCV burner.
N	Costs represent the performance of the dual air zone CCV burner.
O	The scaling factor for SCR only applies to units up to 600 MW

Appendix D – Summary of Emission Reduction Parameters and Calculations

Variables	Definition
X	The average pre-control NOx emission rate (lb/mmBtu), column I in the spreadsheet
Y	The pre-control NOx emission rate, column H in the spreadsheet
Z	The 2003 NOx emission rate based on CEMS data and reported to CAMD; also listed in column J in the CAMD spreadsheet
Z_{bar}	The 2001 to 2003 average annual NOx emission rate based on CEMS data; calculated by averaging the values from the three years of data reported to CAMD.
HI_{bar}	HI_{bar} is the 2001 to 2003 average of annual mmBtu operation for the unit

Baseline Control	Generation of Baseline Control	NOx Control Action	Min Efficiency (A%)	Max Efficiency (B%)	Average or Single Value for Efficiency (C%)	Lowest Achievable Limit (lb/mmBtu) (D)	Vendor Avg. Installed Limit (lb/mmBtu) (D2)	Vendor Avg. Installed Limit (lb/mmBtu) (D3)	Limit Achieved According to efficiencies (lb/mmBtu) (E)
Bin 1a Option 1									
none									
OFA	1st								
LNC1		upgrade to LNC3	0.35+0.717*Max(X,Y)	20%		0.24			
LNC1	since 1997	upgrade to LNC3	0.35+0.717*Max(X,Y)	20%		0.24			
LNC3									
LNC3	since 1997								
Other									
Bin 1a Option 2									
none		LNC2	0.35+0.717*Z	47%		0.24			(1-MIN(A%, B%))*Z
OFA	1st	LNC2	0.35+0.717*Max(X,Y)	47%		0.24			(1-MIN(A%, B%))*MAX(X,Y)
LNC1		upgrade to LNC3	0.35+0.717*Max(X,Y)	20%		0.24			
LNC1	since 1997	upgrade to LNC3	0.35+0.717*Max(X,Y)	20%		0.24			
LNC3		none							
LNC3	since 1997	none							
Other		LNC2	0.35+0.717*Max(X,Y)	47%		0.24			(1-MIN(A%, B%))*MAX(X,Y)
Bin 1a Option 3									
none		LNC3	0.35+0.717*Z	62%		0.24			(1-MIN(A%, B%))*Z
OFA	1st	LNC3	0.35+0.717*Max(X,Y)	62%		0.24			(1-MIN(A%, B%))*MAX(X,Y)
LNC1		LNC3	0.35+0.717*Max(X,Y)	62%		0.24			(1-MIN(A%, B%))*MAX(X,Y)
LNC1	since 1997	LNC3	0.35+0.717*Max(X,Y)	62%		0.24			(1-MIN(A%, B%))*MAX(X,Y)
LNC3		LNC3	0.35+0.717*Max(X,Y)	62%		0.24			(1-MIN(A%, B%))*MAX(X,Y)
LNC3	since 1997	LNC3	0.35+0.717*Max(X,Y)	62%		0.24			(1-MIN(A%, B%))*MAX(X,Y)
Other		LNC3	0.35+0.717*Z	62%		0.24			(1-MIN(A%, B%))*Z
Bin 1a Option 4									
none		ROFA	53%	63%	60%	0.21	0.29		Average(((1-Average(A%,B%,C%)*Zbar),D2)
OFA	1st	ROFA	53%	63%	60%	0.21	0.29		Average(((1-Average(A%,B%,C%)*X),D2)
LNC 1	all	ROFA			59%	0.21	0.26		Average(((1-C%)*Zbar),D2)
LNC 3	all	ROFA			59%	0.21	0.26		Average(((1-C%)*Zbar),D2)
Other		ROFA	53%	63%	60%	0.21	0.29		Average(((1-Average(A%,B%,C%)*Zbar),D2)
Bin 1a Option 5									

Baseline Control	Generation of Baseline Control	NOx Control Action	Min Efficiency (A%)	Max Efficiency (B%)	Average or Single Value for Efficiency (C%)	Lowest Achievable Limit (lb/mmBtu) (D)	Vendor Avg. Installed Limit (lb/mmBtu) (D2)	Vendor Avg. Installed Limit (lb/mmBtu) (D3)	Limit Achieved According to efficiencies (lb/mmBtu) (E)
none		ULNC4	69%	51%	52%	0.18	0.22	0.20	Average(((1-Average(A%,B%,C%)*Zbar),D2,D3)
OFA	1st	ULNC4			65%	0.18	0.22	0.20	Average(((1-C%)*Zbar),D2,D3)
LNC 1	all	ULNC4	69%	51%	52%	0.18	0.22	0.20	Average(((1-Average(A%,B%,C%)*Zbar),D2,D3)
LNC 3	all	ULNC4			15%	0.18	0.22	0.20	Average(((1-C%)*Zbar),D2,D3)
Other		ULNC4	69%	51%	52%	0.18	0.22	0.20	Average(((1-Average(A%,B%,C%)*Zbar),D2,D3)

Variables	Definition
X	The average pre-control NOx emission rate (lb/mmBtu), column I in the spreadsheet
Y	The pre-control NOx emission rate, column H in the spreadsheet
Z	The 2003 NOx emission rate based on CEMS data and reported to CAMD; also listed in column J in the CAMD spreadsheet
Z_{bar}	three years of data reported to CAMD.
HI_{bar}	HI_{bar} is the 2001 to 2003 average of annual mmBtu operation for the unit

Baseline Control	Generation of Baseline Control	NOx Control Action	Min Efficiency (A%)	Max Efficiency (B%)	Average or Single Value for Efficiency (C%)	Lowest Achievable Limit (lb/mmBtu) (D)	Vendor Avg. Installed Limit (lb/mmBtu) (D2)	Vendor Avg. Installed Limit (lb/mmBtu) (D3)	Limit Achieved According to efficiencies (lb/mmBtu) (E)
Bin 1b Option 1									
none		LNC2	0.25+(0.717*Z)	61%		0.12			(1-MIN(A%, B%))*Z
AOFA	since 1997	none							
LNB		none							
LNC1		none							
LNC1	since 1997	none							
LNC2	since 1997	none							
LNC3	since 1997	none							
Bin 1b Option 2									
none		LNC2	0.25+(0.717*Z)	61%		0.12			(1-MIN(A%, B%))*Z
AOFA	since 1997								
LNB									
LNC1		upgrade to	0.35+0.717*Max(X,Y)	15%		0.12 or 0.17			(1-MIN(A%, B%))*Max(X,Y)
LNC1	since 1997	upgrade to	0.35+0.717*Max(X,Y)	15%		0.12 or 0.17			(1-MIN(A%, B%))*Max(X,Y)
LNC2	since 1997	upgrade to	0.35+0.717*Max(X,Y)	15%					(1-MIN(A%, B%))*Max(X,Y)
LNC3	since 1997								
Bin 1b Option 3									
none		LNC3	0.35+0.717*Max(X,Y)	71%		0.12 or 0.17			(1-MIN(A%, B%))*Z
AOFA	since 1997	LNC3	0.35+0.717*Max(X,Y)	71%		0.12 or 0.17			(1-MIN(A%, B%))*Max(X,Y)
LNB		LNC3	0.35+0.717*Max(X,Y)	71%		0.12 or 0.17			(1-MIN(A%, B%))*Max(X,Y)
LNC1		LNC3	0.35+0.717*Max(X,Y)	71%		0.12 or 0.17			(1-MIN(A%, B%))*Max(X,Y)
LNC1	since 1997	LNC3	0.35+0.717*Max(X,Y)	71%		0.12 or 0.17			(1-MIN(A%, B%))*Max(X,Y)
LNC2	since 1997	LNC3	0.35+0.717*Max(X,Y)	71%		0.12 or 0.17			(1-MIN(A%, B%))*Max(X,Y)
LNC3	since 1997	LNC3	0.35+0.717*Max(X,Y)	71%		0.12 or 0.17			(1-MIN(A%, B%))*Max(X,Y)
Bin 1b Option 4									
none		ROFA	53%	63%	60%	.12 or .17			(1-Average(A%,B%,C%))*Zbar)
AOFA	since 1997	ROFA	53%	63%	60%	.12 or .17			(1-Average(A%,B%,C%))*Max(X,Y))
LNB		ROFA			59%	.12 or .17			(1-C%)*Zbar
LNC1	all	ROFA			59%	.12 or .17			(1-C%)*Zbar
LNC2	all	ROFA			59%	.12 or .17			(1-C%)*Zbar

Baseline Control	Generation of Baseline Control	NOx Control Action	Min Efficiency (A%)	Max Efficiency (B%)	Average or Single Value for Efficiency (C%)	Lowest Achievable Limit (lb/mmBtu) (D)	Vendor Avg. Installed Limit (lb/mmBtu) (D2)	Vendor Avg. Installed Limit (lb/mmBtu) (D3)	Limit Achieved According to efficiencies (lb/mmBtu) (E)
LNC3	all	ROFA			59%	.12 or .17			(1-C%)*Zbar
Bin 1b Option 5									
none		ULNC4			65%	.11 or .17	0.16/none given	0.14/none given	Average(((1-C%)*Zbar),D2,D3)
OFA	since 1997	ULNC4			65%	.11 or .17	0.16/none given	0.14/none given	Average(((1-C%)*Max(X,Y)),D2,D3)
LNB		ULNC4			65%	.11 or .17	0.16/none given	0.14/none given	Average(((1-C%)*Zbar),D2,D3)
LNC1		ULNC4			65%	.11 or .17	0.16/none given	0.14/none given	Average(((1-C%)*Zbar),D2,D3)
LNC1	since 1997	ULNC4			65%	.11 or .17	0.16/none given	0.14/none given	Average(((1-C%)*Zbar),D2,D3)
LNC2	since 1997	ULNC4			65%	.11 or .17	0.16/none given	0.14/none given	Average(((1-C%)*Zbar),D2,D3)
LNC3	since 1997	ULNC4			15%	.11 or .17	0.16/none given	0.14/none given	Average(((1-C%)*Zbar),D2,D3)

Variables	Definition
X	The average pre-control NOx emission rate (lb/mmBtu), column I in the spreadsheet
Y	The pre-control NOx emission rate, column H in the spreadsheet
Z	The 2003 NOx emission rate based on CEMS data and reported to CAMD; also listed in column J in the CAMD spreadsheet
Z_{bar}	The 2001 to 2003 average annual NOx emission rate based on CEMS data; calculated by averaging the values from the three years of data reported to CAMD.
HI_{bar}	HI_{bar} is the 2001 to 2003 average of annual mmBtu operation for the unit

Baseline Control	Generation of Baseline Control	NOx Control Action	Min Efficiency (A%)	Max Efficiency (B%)	Average or Single Value for Efficiency (C%)	Lowest Achievable Limit (lb/mmBtu) (D)	Limit Achieved According to efficiencies (lb/mmBtu) (E)
Bin 2 Option 1							
none	--	none					
OFA	2nd	none					
OFA	since 1997	none					
LNB	1st	AOFA	0.285+0.541*MAX(X,MAX(Y,Z))	15%		0.32	(1-MIN(A%, B%))*MAX(X,Y)
LNB	2nd	AOFA	0.285+0.541*MAX(X,MAX(Y,Z))	15%		0.32	(1-MIN(A%, B%))*MAX(X,Y)
LNB	since 1997	AOFA	0.285+0.541*MAX(X,MAX(Y,Z))	15%		0.32	(1-MIN(A%, B%))*MAX(X,Y)
LNBO	1st	none					
LNBO	2nd	none					
LNBO	since 1997	none					
Bin 2 Option 2							
none	--	state of the art LNB	0.135+(0.541*Z)	57%		0.32	(1-MIN(A%, B%)*MAX(X,MAX(Y,Z))
O (other)	--	none					
OFA	2nd	state of the art LNB	0.135+(0.541*MAX(X,MAX(Y,Z))	57%		0.32	(1-MIN(A%, B%)*MAX(X,MAX(Y,Z))
LNB	1st	AOFA	0.285+0.541*MAX(X,MAX(Y,Z))	15%		0.32	
LNB	2nd	AOFA	0.285+0.541*MAX(X,MAX(Y,Z))	15%		0.32	
LNB	since 1997	AOFA	0.285+0.541*MAX(X,MAX(Y,Z))	15%		0.32	
LNBO	1st	none					

Baseline Control	Generation of Baseline Control	NOx Control Action	Min Efficiency (A%)	Max Efficiency (B%)	Average or Single Value for Efficiency (C%)	Lowest Achievable Limit (lb/mmBtu) (D)	Limit Achieved According to efficiencies (lb/mmBtu) (E)
LNBO	2nd	none					
LNBO	since 1997	none					
Bin 2 Option 3							
none	--	AOFA			24%	0.32	$(1\text{-}C\%)*Z_{bar}$
OFA	2nd	none					
LNB	1st	AOFA			22%	0.32	$(1\text{-}C\%)*Z_{bar}$
LNB	2nd	AOFA			22%	0.32	$(1\text{-}C\%)*Z_{bar}$
LNB	since 1997	AOFA			22%	0.27	$(1\text{-}C\%)*Z_{bar}$
LNBO	1st	upgrade to AOFA			22%	0.32	$(1\text{-}C\%)*Z_{bar}$
LNBO	2nd	none					
LNBO	since 1997	none					
Bin 2 Option 4							
none	--	ULNB	59%	74%	62.5%	0.32	$(1\text{-Average}(A\%,B\%, C\%))*Z_{bar}$
OFA	2nd	ULNB	59%	74%	62.5%	0.27	(1-Average(A%,B%, C%))*Y
LNB	1st	ULNB	26%	36%	33%	0.32	$(1\text{-Average}(A\%, B\%, C\%)*Z_{bar}$
LNB	2nd	ULNB			11%	0.32	$(1\text{-}C\%)*Z_{bar}$
LNB	since 1997	none					
LNBO	1st	ULNB	26%	36%	33%	0.27	$(1\text{-Average}(A\%, B\%, C\%)*Z_{bar}$
LNBO	2nd	ULNB			11%	0.27	$(1\text{-}C\%)*Z_{bar}$
LNBO	since 1997	none					
Bin 2 Option 5							
none	--	ULNBO	59%	74%	68%	0.27	$(1\text{-Average}(A\%,B\%, C\%))*Z_{bar}$
OFA	2nd	ULNBO	59%	74%	68%	0.27	(1-Average(A%,B%, C%))*Y
LNB	1st	ULNBO	26%	36%	33%	0.27	$(1\text{-Average}(A\%, B\%, C\%)*Z_{bar}$
LNB	2nd	ULNBO			32%	0.27	$(1\text{-}C\%)*Z_{bar}$
LNB	since 1997	AOFA			22%	0.27	$(1\text{-}C\%)*Z_{bar}$
LNBO	1st	ULNBO	26%	36%	33%	0.27	$(1\text{-Average}(A\%, B\%, C\%)*Z_{bar}$

Baseline Control	Generation of Baseline Control	NOx Control Action	Min Efficiency (A%)	Max Efficiency (B%)	Average or Single Value for Efficiency (C%)	Lowest Achievable Limit (lb/mmBtu) (D)	Limit Achieved According to efficiencies (lb/mmBtu) (E)
LNBO	2nd	ULNBO			11%	0.27	$(1-C\%)*Z_{bar}$
LNBO	since 1997	none					
Bin 2 Option 6							
none	--	ULNBO	59%	74%	68%	0.27	$(1-Average(A\%,B\%, C\%))*Z_{bar}$
OFA	2nd	ULNBO	59%	74%	68%	0.27	(1-Average(A%,B%, C%))*Y
LNB	1st	ULNBO	26%	36%	33%	0.27	$(1-Average(A\%, B\%, C\%)*Z_{bar}$
LNB	2nd	ULNBO			32%	0.27	$(1-C\%)*Z_{bar}$
LNB	since 1997	AOFA			22%	0.27	$(1-C\%)*Z_{bar}$
LNBO (0 to 300 MW)	1st	OEC	20%	60%	44%	0.18	$(1-Average(A\%, B\%, C\%)*Z_{bar}$
LNBO (0 to 300 MW)	2nd	OEC	20%	60%	44%	0.18	$(1-Average(A\%, B\%, C\%)*Z_{bar}$
LNBO (0 to 300 MW)	since 1997	OEC	20%	60%	44%	0.18	$(1-Average(A\%, B\%, C\%)*Z_{bar}$
LNBO (greater than 300 MW)	1st	ULNBO	26%	36%	33%	0.27	$(1-Average(A\%, B\%, C\%)*Z_{bar}$
LNBO (greater than 300 MW)	2nd	ULNBO			11%	0.27	$(1-C\%)*Z_{bar}$
LNBO (greater than 300 MW)	since 1997	none					
Bin 2 Option 7							
none	--	ROFA	39%	49%	45%	0.25	$(1-Average(A\%,B\%, C\%))*Z_{bar}$
OFA	all	ROFA	39%	49%	45%	0.25	(1-Average(A%,B%, C%))*Y

Baseline Control	Generation of Baseline Control	NOx Control Action	Min Efficiency (A%)	Max Efficiency (B%)	Average or Single Value for Efficiency (C%)	Lowest Achievable Limit (lb/mmBtu) (D)	Limit Achieved According to efficiencies (lb/mmBtu) (E)
LNB	all	ROFA	33%	55%	45%	0.21	(1-Average(A%, B%, C%)*Z_{bar}
LNBO	all	ROFA	33%	55%	45%	0.21	(1-Average(A%, B%, C%)*Z_{bar}

Variables	Definition
X	The average pre-control NOx emission rate (lb/mmBtu), column I in the spreadsheet
Y	The pre-control NOx emission rate, column H in the spreadsheet
Z	The 2003 NOx emission rate based on CEMS data and reported to CAMD; also listed in column J in the CAMD spreadsheet
Z_{bar}	the values from the three years of data reported to CAMD.
HI_{bar}	HI_{bar} is the 2001 to 2003 average of annual mmBtu operation for the unit

Baseline Control	Generation of Baseline Control	NOx Control Action	Min Efficiency (A%)	Max Efficiency (B%)	Average or Single Value for Efficiency (C%)	Lowest Achievable Limit (D)	Vendor Max Installed Limit (D2)	Vendor Avg. Installed Limit (D3)	Limit Achieved According to efficiencies (E)
Bin 3 Option 1									
none	--	none							
OFA	1st	none							
LNB	1st	add state of the art OFA	0.285+0.541*Z	15%		0.32			(1-MIN(A%, B%))*Z
LNB	2nd	add state of the art OFA	0.285+0.541*Z	15%		0.32			(1-MIN(A%, B%))*Z
LNB	since 1997	add state of the art OFA	0.285+0.541*Z	15%		0.32			(1-MIN(A%, B%))*Z
LNBO	2nd	none							
LNBO	since 1997	none							
SCR	since 1997	none							
Bin 3 Option 2									
none	--	add state of the art burner	0.135+0.541*Z	15%		0.18			(1-MIN(A%, B%))*Z
OFA	1st	add state of the art burner	0.135+0.541*MAX(X,Y)	15%		0.18			(1-MIN(A%, B%))*MAX(X,Y)
LNB	1st	add state of the art OFA	0.285+0.541*Z	15%		0.32			(1-MIN(A%, B%))*Z
LNB	2nd	add state of the art OFA	0.285+0.541*Z	15%		0.32			(1-MIN(A%, B%))*Z
LNB	since 1997	add state of the art OFA	0.285+0.541*Z	15%		0.32			(1-MIN(A%, B%))*Z
LNBO	2nd	none							
LNBO	since 1997	none							
SCR	since 1997	none							
Bin 3 Option 3									
none	--	add AOFA			24%	0.18			$(1-C\%)*Z_{bar}$
OFA	1st	upgrade to AOFA			24%	0.18			(1-C%)*X
LNB	1st	add AOFA			22%	0.18			$(1-C\%)*Z_{bar}$
LNB	2nd	add AOFA			22%	0.18			$(1-C\%)*Z_{bar}$
LNB	since 1997	add AOFA			22%	0.18			$(1-C\%)*Z_{bar}$
LNBO	2nd	none							
LNBO	since 1997	none							
SCR	since 1997	none							
Bin 3 Option 4									
none	--	add ULNB	59%	74%	62.5%	0.18			$(1-Average(A\%,B\%, C\%))*Z_{bar}$
OFA	1st	add ULNB	59%	74%	62.5%	0.18			(1-Average(A%,B%, C%))*Y
LNB	1st	upgrade to ULNB	43%	51%	48%	0.18			$(1-Average(A\%, B\%, C\%)*Z_{bar}$
LNB	2nd	upgrade to ULNB			25%	0.18			$(1-C\%)*Z_{bar}$

Baseline Control	Generation of Baseline Control	NOx Control Action	Min Efficiency (A%)	Max Efficiency (B%)	Average or Single Value for Efficiency (C%)	Lowest Achievable Limit (D)	Vendor Max Installed Limit (D2)	Vendor Avg. Installed Limit (D3)	Limit Achieved According to efficiencies (E)
LNB	since 1997	none							
LNBO	2nd	upgrade to ULNB			25%	0.158	0.2	0.17	Average(((1-C%)*Zbar),D2,D3)
LNBO	since 1997	none							
SCR	since 1997	none							
Bin 3 Option 5									
none	--	add ULNBO			68%	0.158			(1-C%)*Z_{bar}
OFA	1st	add ULNBO			68%	0.158			(1-C%)*Y
LNB	1st	upgrade to ULNBO			33%	0.158			(1-C%)*Z_{bar}
LNB	2nd	upgrade to ULNBO			32%	0.158			(1-C%)*Z_{bar}
LNB	since 1997	add AOFA			22%	0.158			(1-C%)*Z_{bar}
LNBO	2nd	upgrade to ULNBO	26%	36%	33%	0.158			Average(((1-C%)*Zbar),D2,D3)
LNBO	since 1997	none							
SCR	since 1997	none							
Bin 3 Option 6									
none	--	add ROFA	39%	49%	45%				(1-Average(A%,B%, C%))*Z_{bar}
OFA	1st	add ROFA	39%	49%	45%				(1-Average(A%,B%, C%))*Y
LNB	all	add ROFA	33%	55%	45%				(1-Average(A%, B%, C%)*Z_{bar}
LNBO	all	add ROFA	33%	55%	45%				(1-Average(A%, B%, C%)*Z_{bar}
SCR	since 1997	none							

Variables	Definition
X	The average pre-control NOx emission rate (lb/mmBtu), column I in the spreadsheet
Y	The pre-control NOx emission rate, column H in the spreadsheet
Z	The 2003 NOx emission rate based on CEMS data and reported to CAMD; also listed in column J in the CAMD spreadsheet
Z_{bar}	reported to CAMD.
HI_{bar}	HI_{bar} is the 2001 to 2003 average of annual mmBtu operation for the unit

Baseline Control	Generation of Baseline Control	NOx Control Action	Min Efficiency (A%)	Max Efficiency (B%)	Average or Single Value for Efficiency (C%)	Lowest Achievable Limit (D)	Vendor Max Installed Limit (D2)	Limit Achieved According to efficiencies (E)
Bin 4 Option 1								
none	--	coal reburning	0.135+(0.541*Z)	50%				(1-MIN(A%, B%))*Z
OFA	since 1997	coal reburning	0.135+(0.541*MAX(X,Y)	50%				(1-MIN(A%, B%))*MAX(X,Y)
Bin 4 Option 2								
none	--	Micronized Reburning			57%			(1-C%)*(Max(X,Y)
OFA	since 1997	Micronized Reburning			57%			(1-C%)*Z
Bin 5 Option 1								
none	--	non-plug in combustion controls	0.135+0.541*Z	60%	60%			
LNCB	late 80s early 90s	non-plug in combustion controls	0.135+(0.541*MAX(Y,Z))	60%	60%			
Bin 5 Option 2								
none	--	a ULNCB	52%	64%	64%			(1-Average(A%,B%)*Zbar)
LNCB	late 80s early 90s	a ULNCB	52%	64%	64%	0.396	0.66	Average(((1-Average(A%,B%)*Max(X,Y)),D2)
Bin 7 Option 1								
none	--	a LNB for vertically-fired units	63%	69%	68%	0.12		(1-Average(A%,B%,C%))*Zbar
LNBO	2nd generation	none						
LNBO	since 1997	none						
OFA	since 1997	a LNB for vertically-fired units	63%	69%	68%	0.32		(1-Average(A%,B%,C%))*Max(X,Y)

Appendix E – Cost and Emissions Reduction for EGU's Per Option

[To be added]