United States Department of the Interior

NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

IN REPLY REFER TO:

August 29, 2008

N3615 (2350)

Shelley Kaderly
Air Division Administrator
Nebraska Department of Environmental Quality
1200 "N" Street, Suite 400
P.O. Box 98922
Lincoln, Nebraska 68509

Dear Ms. Kaderly:

Thank you for inviting us to provide comments on the Best Available Retrofit Technology (BART) analyses and draft permits provided by the Nebraska Department of Environmental Quality (NDEQ) for Gerald Gentleman Station (GGS) Units #1 & #2 and Nebraska City Station (NCS) Unit #1. Our interest in this action stems from our obligation to protect visibility at Badlands, Wind Cave, and Rocky Mountain National Parks, and Wichita Mountains and Mingo Wildernesses. We have summarized our major comments in this letter and provide detailed comments in the enclosure.

GGS is located 300 km from the nearest Class I areas (Badlands) and NCS is located 500 km from the nearest Class I area (Hercules Glades). The air quality modeling performed to date and reported in your assessment of BART and the Fact Sheets indicate that the GGS "causes" visibility impairment at Badlands, Wind Cave, and Rocky Mountain National Parks and Wichita Mountains Wilderness, and "contributes" to visibility impairment at Mingo and Hercules Glades Wildernesses. NCS "contributes" to visibility impairment at Hercules Glades Wilderness.

GGS is a greater than 750 megawatt power plant and is therefore subject to EPA's determination of presumptive BART emissions limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) found in Sections IV.E.4 and IV.E.5, Appendix Y of Part 51 in the Code of Federal Regulations. NCS has one operating unit and another unit under construction that total more than 750 megawatts. Therefore, the NCS Unit 1 is subject to the same presumptive BART emissions limits. For GGS, the State's draft permit requires the presumptive NO_X limit at Unit 1 and slightly above presumptive at Unit 2. The State draft permit rejects presumptive limits for SO_2 and establishes BART as no control for SO_2. For NCS, the State draft permit requires presumptive NO_X limit at Unit 1 and rejects the presumptive limit for SO_2, proposing BART for SO_2 as no control.

Based on the information we have received from the State, and our knowledge of similar sources in other states, the emissions control costs are in line with EPA's BART guidance assumptions. Given the lack of detailed information regarding the methods used by the source's contractors when they developed cost estimates, we can not determine if costs at these facilities are significantly higher (as the sources claim) than those used to develop the EPA presumptive. Citing costs higher than those cited by EPA due to inflationary pressures does not remove these sources from being subject to EPA's established BART controls. To have a limit less stringent than EPA's established BART levels, the State would need to establish that the source would face exceptional costs, due to the source's configuration or other plant specific features, compared to the costs of other sources subject to presumptive BART emissions limits. The current information that we have does not support this position.

Calculation of Visibility Improvement

We believe that it is appropriate to consider both the degree of visibility improvement in a given Class I area, as well as the cumulative—not average—effects of improving visibility across all of the Class I areas affected. It is not appropriate to use the same metric to evaluate the effects of reducing emissions from a BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas. The information on costs per unit of improved visibility for GGC and NCS was based solely on the effect at one Class I area. For GCS similar improvements would likely occur at Wind Cave NP perhaps halving the dollar per deciview numbers cited by the source. There are also additional benefits at other Class I areas. There is not sufficient information for us to apply a complete summing calculation and we would request that the State conduct such an assessment before taking final action.

In addition, for SO_2, it appears that using flue gas desulfurization would achieve an emission rate substantially below the presumptive rate since the coal used at GGS and NCS has much lower sulfur content than most utility coal. The decision by the State to set BART at "no control" is based on the sources' evaluations that visibility improvement gained by installation of FGD for the costs involved is not in the range of effect and cost that EPA required in development of BART limits. We find significant problems with the sources' analyses. Two major problems are the use of the presumptive emission limit to represent the emission that would result from application of SO_2 controls at GGS and NCS, and the lack of a clear methodology to estimate costs equivalent to the methodology provided in the OAQPS Control Cost Manual.

Consideration of Post Combustion NO_X Control

Given the modeled importance of nitrate there is also reason to believe that selective non-catalytic reduction or selective catalytic reduction controls may be just as cost effective as SO_2 reductions in improving visibility. However, because of the manner in which the sources' contractor developed cost effectiveness (focusing on incremental costs alone), it is not possible to independently compare options for NO_X control.

Visibility Improvement Metrics

The BART Guidelines represent an attempt to create a workable approach to estimating visibility impairment. As such, they require several assumptions, simplifications, and shortcuts about when visibility is impaired in a Class I area, and how much impairment is occurring. The Guidelines do not attempt to address the geographic extent of the impairment, but assume that all Class I areas are created equal, and that there is no difference between widespread impacts in a

Class I area and isolated impacts in a Class I area. To address the problem of geographic extent, we have been looking at the cumulative impacts of a source on all Class I areas affected, as well as the cumulative benefits from reducing emissions. While there are certainly more sophisticated approaches to this problem, we believe that this is the most practical, especially when considering the modeling techniques and information available. Therefore, until we can develop a second-level, more refined analysis, we continue to believe that our "simple summing" approach fills a void left by NDEQ in cases of power plants having significant impacts upon two or more Class I areas.

Summary

In summary, we do not believe that the information supplied to date adequately supports the emission limits presented as BART in the draft permits. At this time, we see no reason to support any conclusion other than presumptive BART, or better, emissions limits for SO_2 and NO_X being required at both facilities. We look forward to working with NDEQ and EPA as this process advances. We believe that good communication and sharing of information will help expedite this consensus, and suggest that you contact Bruce Polkowsky--NPS (bruce_polkowsky@nps.gov, 303-987-6944), or Tim Allen--FWS (tim_allen@fws.gov, 303-914-3802) if you have any questions or comments.

Sincerely,

Christine L. Shaver
Chief, Air Resources Division
National Park Service

Sincerely,

Sandra V. Silva

Sandra V. Silva
Chief, Branch of Air Quality
U.S. Fish and Wildlife Service

Enclosure:
National Park Service (NPS) and U.S. Fish and Wildlife Service (FWS) Source-Specific Comments on Nebraska Department of Environmental Quality Proposed BART Permits with Appendices

cc:

Rebecca Weber
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901 N 5th Street
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Mingo Refuge Manager
Wichita Mountains Refuge Manager
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National Park Service (NPS) and U.S. Fish and Wildlife Service (FWS) Source-Specific Comments on Nebraska Department of Environmental Quality Proposed BART Permits

August 29, 2008

Nebraska Public Power District (NPPD)
Gerald Gentleman Station (GGS) Units #1 and #2

NPPD operates the GGS, which includes two Electric Generating Units (EGUs), near Sutherland, Nebraska. Modeling analyses have shown that GGS causes visibility impairment in NPS-administered Badlands National Park (NP), Wind Cave NP, and Rocky Mountain NP Class I areas and the FWS-administered Wichita Mountains Wilderness Class I area. GGS also contributes to visibility impairment at the Hercules Glades (U.S. Forest Service-administered) and Mingo (FWS-administered) Class I areas. The GGS includes two BART-eligible boilers which burn pulverized Powder River Basin (PRB) sub-bituminous coal (8,576 Btu/lb; 0.30% sulfur; 4.69% ash in 2001). Historic emissions, based upon data from EPA's Clean Air Markets (CAM) database, are illustrated in the attached charts (Figures 1.a. – 1.d.).

Unit #1 is a dry-bottom, wall-fired boiler rated at 665 MW (net). Unit #1 is equipped with a fabric filter to control particulate matter (PM_{10}). It appears that Low-NO_x Burners (LNB) and Over-Fire Air (OFA) were installed 2005 – 2006 to reduce nitrogen oxides (NO_x) from about 0.45 pounds per million Btu (lb/mmBtu) and 12,000 – 14,000 tons per year (tpy) to about 0.2 lb/mmBtu and about 6,000 tpy. There are no controls for sulfur dioxide (SO_2), which typically is emitted at 0.5 – 0.6 lb/mmBtu and 14,000 – 16,000 tpy.

Unit #2 is a dry-bottom, wall-fired boiler rated at 700 MW (net). Unit #2 is equipped with a fabric filter to control particulate matter (PM_{10}). There are no controls for SO_2, which typically is emitted at 0.5 – 0.6 lb/mmBtu and 14,000 – 16,000 tpy. There are no controls for NO_x, which typically is emitted at 0.30 – 0.35 lb/mmBtu and 8,000 – 10,000 tpy.

On June 19, 2008, we were notified that NPPD's BART analyses were available on the Nebraska Department of Environmental Quality (NDEQ) website. The following are our comments and questions regarding those documents.

<u>Cost-Effectiveness Metrics</u>

NPPD has presented extensive information to support its contention that costs of pollution controls are increasing, and that this should be taken into account in these cost analyses. NPPD appears to have used cost escalation as its rationale to present a mix of costing techniques that borrow from the OAQPS Control Cost Manual (Cost Manual), and NPPD's consultant's proprietary methods. We agree with NPPD that inflation should be a factor in these cost analyses. In fact, we included just such a factor in our own analyses that we discuss later in this document. However, we do not agree that NPPD, or any source, should be able to pick and choose bits and pieces from among the various methods for estimating pollution control costs. The BART analysis is based upon judgments as to the reasonableness of costs and benefits of reducing emissions from a specific source relative to costs borne by similar sources and the benefits of reducing emissions at those sources. EPA guidance states:

> The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the OAQPS Control Cost Manual). In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible.

NPPD should follow this guidance.

Our contention that the Cost Manual should be the primary source for developing cost analyses that are consistent across the nation and provide a common means for assessing costs is further supported by this November 7, 2007, statement from EPA Region 8 to the North Dakota Department of Health:

> The SO_2 and PM cost analyses were completed using the CUECost model. According to the BART Guidelines, in order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual. Therefore, these analyses should be revised to adhere to the Cost Manual methodology.

We believe that this guidance from EPA reaffirms our comments and that NPPD should revise its cost analyses to reflect a more consistent use of the Cost Manual.

Much of NPPD's argument against installing pollution controls at GGS centers on the increasing worldwide costs of pollution controls in general. If this argument is carried to its logical conclusion, then no EGU should be required to install any pollution control equipment that involves a large capital expenditure. Instead, we believe that pollution control is an inherent cost of doing business, and that NPPD must show why the GGS plant would experience uniquely higher costs for pollution controls than would normally be considered reasonable.

Finally, BART is not necessarily the most cost-effective solution. Instead, it represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors.

Visibility Improvement Metrics

We continue to believe that it is appropriate to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected. It is not appropriate to use the same metric to evaluate the effects of reducing emissions from a BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas. And, it also is not appropriate to evaluate impacts at one Class I area, while ignoring others that are similarly significantly impaired. If emissions from GGS are reduced, the benefits will be spread well beyond only the most-impacted Class I area. The State should consider all benefits when establishing BART limits. While NPPD presented data describing improvements to visibility at Badlands NP that would result from the various control scenarios it investigated, NPPD still has not explained how it incorporated this information on impacts upon all Class I areas into its BART decision. For example, the Oregon Department of Environmental Quality (OR DEQ) has recently posted on its website[1] a proposal to require under the BART program that the Boardman power plant install a dry scrubber and Selective Catalytic Reduction (SCR). As part of its BART determination, OR DEQ evaluated the benefits of various control strategies on all 14 of the Class I areas within 300 km of the plant. The following is an excerpt from comments we sent to OR DEQ in January:

> The BART Guidelines represent an attempt to create a workable approach to estimating visibility impairment. As such, they require several assumptions, simplifications, and shortcuts about when visibility is impaired in a Class I area, and how much impairment is occurring. The Guidelines do not attempt to address the geographic extent of the impairment, but assume that all Class I areas are created equal, and that there is no difference between widespread impacts in a Class I area and isolated impacts in a Class I area. To address the problem of geographic extent, we have been looking at the cumulative impacts of a source on all Class I areas affected, as well as the cumulative benefits from reducing emissions. While there are certainly more sophisticated approaches to this problem, we believe that this is the most practical, especially when considering the modeling techniques and information available. In this case, we applied this cumulative approach to the Boardman analysis and found that the cumulative impact from the baseline condition on visibility in the 14 Class I areas is 29.7 dv, with a total of 2,367 "days" of impaired visibility across the 14 Class I areas.

We understand that OR DEQ used a similar approach in its analyses.

NPPD has effectively ignored the other Class I areas where GGS is also causing or contributing to visibility impairment. We would be pleased to work with NDEQ to further develop this approach.

NO_x BART[2]

NPPD has proposed only LNB and OFA as NO_x controls (They have already been installed on Unit #1.) to meet the presumptive BART limit.

NPPD has eliminated Selective Non-Catalytic Reduction (SNCR) from consideration without sufficient justification.

This has occurred on the basis that it is not technically feasible because of high temperatures measured in a similar boiler. However, it appears from the CAM data plotted in Figure 1.c. that NO_x emissions from the two "similar" boilers at GGS are significantly different. Therefore, we question not only NPPD's assumption that it can eliminate SNCR on the basis of temperature characteristics at a distant boiler, but also whether it can assume that the two boilers at GGS are so similar that they can be evaluated in combination, not individually. (This same concern applies to the rest of NPPD's analyses of NO_x controls.) Thus, NPPD should show, with data specific to the GGS boilers, that this is the case at the GGS facility also.

NPPD rejected Selective Catalytic Reduction (SCR) as too expensive on a cost-per-ton-of-pollutant-removed ($/ton) and cost-per-deciview-improvement ($/dv) basis. Table 1

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[1] http://www.deq.state.or.us/aq/haze/pge.htm

[2] Presumptive BART for these wall-fired boilers burning sub-bituminous coal is 0.23 lb/mmBtu.

below uses company data and estimates that it would cost about \$2,300/ton to improve visibility by 1.15 dv at Badlands NP. NPPD did not evaluate the cumulative benefits of improving visibility at the other Class I areas.

Table 1. Nebraska Public Power--
Gerald Gentleman—NPPD estimates **LNB+SCR burning PRB sub-bituminous**

Unit	#1	Source	#2
Rating (MW Net) each	665	company report	700
Rating (mmBtu/hr)	7,538	company report	7,538
Current Emissions (tpy)	13,408	2001 - 2003CAM data	8,894
Current Emissions (lb/mmBtu)	0.46	2001 - 2003CAM data	0.32
Current Uncontrolled Emissions (tpy)	13,408	2001 - 2003CAM data	8,894
Current Control Efficiency	47%	calculated	0%
Company Cost-benefit Analysis			
Future Uncontrolled Emissions (tpy)	15,122	company report	15,122
Controlled Emissions (lb/mmBtu)	0.08	company report	0.08
Overall Control Efficiency	83%	calculated	75%
Controlled emissions (tpy)	2,659	calculated	2,659
Emission Reductions (tpy)	12,463	company report	12,463
Capital Cost	\$ 257,540,500	company report	\$ 257,540,500
Capital Cost (\$/kW)	\$ 387	calculated	\$ 368
O&M Cost			
Annualized Cost	\$ 28,625,500	company report	\$ 28,625,500
Cost-Effectiveness (\$/ton)	\$ 2,297	company report	\$ 2,297

A significant reason for the poor cost-effectiveness of this option is the low (75% - 83%) NO_x control efficiency assumed for a technology that should be able to achieve 90% control.[3] And, NPPD's almost \$400/kW capital cost is much higher than the \$40 - \$50/kW range estimated for SCR at this facility by EPA's Cost Tool database.

<u>NPPD has underestimated the ability of modern NO_x control systems.</u>
NPPD estimates that addition of SCR can reduce NO_x by 75% - 83% to 0.08 lb/mmBtu. SCR has been retrofitted to many wall-fired eastern PC boilers that are now achieving 0.05 lb/mmBtu on a 30-day rolling average basis. We have found at least 16 examples (Please see enclosed Table 2.) in EPA's Clean Air Markets (CAM) database of boilers similar to those at GGS that have been retrofitted with SCR and are achieving annual[4] emission rates well below NPPD's "target" for SCR. We were able to find 2006 hourly emissions in EPA's CAM database for 14 of those EGUs, and charts showing those emissions are included in Appendix A. It appears that the majority of those retrofit SCR systems are able to achieve 0.05 lb/mmBtu when in use during the eastern ozone season.[5]

[3] NPPD has combined these two boilers for its analysis, even though NO_x emissions from these boilers differ substantially. Separate analyses are preferable.
[4] While it is likely that 30-day rolling average emission rates would be somewhat higher, it is unlikely that they would exceed the NPPD target.
[5] For example, we recently received a proposal from a major SCR vendor to install its system on a wall-fired boiler burning PRB coal and reduce NO_x emissions to 0.05 lb/mmBtu.

It is likely that many of these EGUs are burning eastern bituminous coals with higher fuel-bound nitrogen than that burned at GGS. Because "fuel nitrogen can account for up to 80 percent of total NO_x from coal combustion,"[6] it should be easier for GGS to achieve lower NO_x emissions than an EGU burning coal with higher fuel-bound nitrogen. If SCR is capable of reducing emissions below NPPD's target, then the amount of the reductions and consequent visibility improvements will increase.

NPPD's NO_x & SCR costs are overestimated.
We applied the procedures described in Section 4, Chapter 2 of the Cost Manual to the GGS boilers.[7] Because modern SCR systems are typically designed to achieve 90+% NO_x reductions, we used 0.05 lb/mmBtu as our target. Using most of the NPPD information and estimates, we estimated a Total Annual Cost of $12 million, and produced cost-effectiveness estimates of less than $1,000/ton. (Please see Table 3. below.)

Table 3. NPS estimates for SCR at NPPD–Gerald Gentleman **LNB+SCR burning PRB sub-bituminous**

Unit	#1		#2
Rating (MW Gross) each	665	company report	700
Rating (mmBtu/hr)	7,538	company report	7,538
Current Emissions (tpy)	13,408	2001 - 2003CAM data	8,894
Current Emissions (lb/mmBtu)	0.46	2001 - 2003CAM data	0.32
Current Uncontrolled Emissions (tpy)	13,408	2001 - 2003CAM data	8,894
Current Control Efficiency	47%	calculated	0%
NPS Cost-benefit Analysis			
Future Uncontrolled Emissions (tpy)	15,122	company report	15,122
Controlled Emissions (lb/mmBtu)	0.05	NPS estimate	0.05
Overall Control Efficiency	89%	calculated	84%
Controlled emissions (tpy)	1,633	calculated	2,358
Emission Reductions (tpy)	13,489	calculated	12,764
Capital Cost	$ 44,424,446	NPS estimate	$ 44,424,446
Capital Cost ($/kW)	$ 67	calculated	$ 63
O&M Cost	$ 2,942,821	NPS estimate	$ 2,794,842
Annualized Cost	$ 12,072,668	NPS estimate	$ 11,924,689
Cost-Effectiveness ($/ton)	$ 895	NPS estimate	$ 934

We estimate that SCR would improve visibility by 1.21 dv at Badlands NP, but we did not have sufficient data to evaluate the cumulative benefits of improving visibility at the other Class I areas.

NO_x BART Conclusions:
Use of EPA guidance and data results in cost-effectiveness values for combustion modifications plus SCR of less than $1,000/ton. This cost-effectiveness appears reasonable, given the magnitude and extent of GGS' impacts upon visibility.

[6] EPA "Compilation of Air Pollutant Emission Factors" (AP-42), section 1.1.3.3.
[7] Our calculations are contained in the attached Excel workbook and in Appendix B.

We submitted similar comments to OR DEQ in January 2008, and OR DEQ responded by determining that the Boardman power plant should install SCR and achieve 0.07 lb/mmBtu by July 1, 2017, at a cost of $2,583 per ton of NO_x removed. We recommend that NDEQ consider the actions of OR DEQ and re-evaluate SCR at GGS in that context.

NPPD should re-do its SCR analysis in the format presented by the OAQPS Control Cost Manual[8] and model the effects on all Class I areas of reducing NO_x to not greater than 0.07 lb/mmBtu and provide the information to develop the "fifth factor" in the BART process.

<u>SO_2 BART[9]</u>

NPPD has proposed no additional controls for BART for SO_2. NPPD estimates that wet and dry scrubbers can only achieve 0.15 lb/mmBtu on a 30-day rolling average, and has rejected them as too expensive.

<u>NPPD has underestimated the ability of modern SO_2 control systems.</u>
Unlike the retrofittng of NO_x controls that is highly dependent upon the existing boiler configuration, the SO_2 controls that could be added at GGS would be completely new, and should therefore be capable of performing as well as at a greenfield facility.

It is easier to achieve a higher SO_2 control efficiency on coals with higher inherent, uncontrolled emissions. And, as uncontrolled emissions increase, controlled emissions will also tend to increase despite the increasing SO_2 control efficiency. It follows that it is harder to achieve a higher control efficiency on a gas stream with a lower inlet SO_2 concentration, but easier to achieve a lower outlet concentration. So, if one can achieve lower emission rate on a "dirtier" gas stream, it would indicate a higher degree of scrubbing success. All of this must be considered when determining the level of SO_2 control that is feasible for a given coal.[10]
Inspection of Table 4.a. (below) reveals that wet FGD systems are achieving (e.g., Navajo Generating Station, Intermountain Power) or being proposed/permitted at 0.04 – 0.09 lb/mmBtu on coals with much higher uncontrolled emissions than currently seen at GGS. Based upon these data and considering GGS' cleaner coal quality, we believe that a new wet FGD at GGS should be able to achieve 0.04 lb/mmBtu[11] (or lower) on a 30-day rolling average.

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[8] It would be very helpful if NPPD would provide vendor quotes and supporting documentation for major cost items.
[9] EPA's presumptive SO_2 BART limit for similar boilers is 95% control or 0.15 lb/mmBtu.
[10] For the sake of consistency, it is assumed that the SO_2 emission factor is dependent upon the coal type, but independent of the boiler type. The natural process of retention of sulfur in the ash is just as fundamental a characteristic of the coal burned as its sulfur content and its heating value. So, bituminous coals would emit 95% of their sulfur content as SO_2, while sub-bituminous coals would emit 87.5%, and lignites 75%.
[11] For example, EPA has proposed to permit the Desert Rock power plant at 0.06 lb/mmBtu (24-hour average) despite coal with almost three times the uncontrolled emissions as at GGS.

Table 4.a. Wet Scrubber SO_2 Rankings (30-day rolling averaging period)

SO2				Coal Quality			Capacity	Emissions or Limits	Control
Facility Name	Unit	Status	Permit #	%S	(Btu/lb)	(lb/mmBtu)	MW	(lb/mmBtu)	(%)
NPPD-GGS	1&2	operating	NE	0.30	8576	0.555	1365	0.040*	92.8%*
Colstrip	4	operating	MT	0.75	8487	1.546	778	0.093	94.4%
Colstrip	4	operating	MT	0.75	8487	1.546	778	0.091	94.5%
Intermountain Pwr	3	issued	UT-0065	0.75	11193	1.273	950	0.090	92.9%
Navajo	1	operating	AZ	0.53	10919	0.922	803	0.072	92.9%
Navajo	3	operating	AZ	0.53	10919	0.922	803	0.064	93.2%
Sithe-Desert Rock		pending	EPA	0.82	8910	1.611	1500	0.060	96.3%
Sithe-Toquop		application	NV	1.4	8215	2.982	750	0.060	98.0%
Mustang		application	NM	1.56	8647	3.157	300	0.060	98.1%
Intermountain Pwr	2	operating	UT	0.48	11817	0.772	820	0.059	92.4%
Navajo	2	operating	AZ	0.53	10919	0.922	803	0.044	95.5%
FPL-Glades		application	FL	1.98	12324	3.053	2x980	0.040	98.7%
Taylor		application	FL	3.46	7475	8.100	800	0.040	99.5%

*Recommended as BART by NPS / FWS

Inspection of Table 4.b. (below) reveals that semi-dry FGD systems are being proposed/permitted at 0.06 – 0.09 lb/mmBtu on coals with much higher uncontrolled emissions than currently used at GGS. Based upon these data and considering GGS' even cleaner coal quality, we believe that a new semi-dry FGD at GGS should be able to achieve 0.06 lb/mmBtu (or lower) on a 30-day rolling average.

Table 4.b. Dry Scrubber SO2 Rankings (30-day rolling averaging period)

SO2				Coal Quality			Capacity	Emissions or Limits	Control
Facility Name	Unit	Status	Permit #	%S	(Btu/lb)	(lb/mmBtu)	MW	(lb/mmBtu)	(%)
NPPD-Gerald Gentleman	1&2	operating	NE	0.30	8576	0.555	1365	0.060*	89.2%*
LS Pwr--High Plains	1	application	CO	0.66	8200	1.409	600	0.090	93.6%
Black Hills Pwr-WYGEN 3		issued	WY	1.20	7950	2.642	100	0.090	96.6%
LS Power-White Pine		draft permit	NV	0.66	8200	1.409	3x530	0.089	93.7%
Basin Electric--Dry Fork		permit	WY	0.47	7800	1.054	385	0.075	92.9%
Newmont Nevada		issued	NV-0036	0.45	8400	0.938	200	0.065	93.1%
LS Power-White Pine		draft permit	NV	0.3	8200	0.640	3x530	0.065	89.8%
LS Pwr--High Plains	1	application	CO	0.46	8200	0.982	600	0.065	93.4%
Sierra Pacific-Ely		application	NV	0.8	8100	1.728	2x750	0.060	96.5%

*Recommended as BART by NPS/FWS

NPPD's FGD costs are overestimated

Dry Scrubber: NPPD has estimated that it would cost over $2,700/ton to control SO_2 using a dry scrubber at GGS. While much of this cost is due to extensive baghouse modifications to accommodate the additional particulate generated in the dry scrubber, the over-$700 capital cost per kilowatt hour (kWh) appears unusually high, especially when compared to the $423/kWh that Great River Energy proposes to spend to add a dry scrubber to its Stanton Unit #1 in North Dakota.

Table 5.a. Gerald Gentleman — NPPD estimates **Dry FGD addition burning PRB sub-bituminous**

Unit	#1	Source	#2
Rating (MW Gross) each	665	company report	700
Rating (mmBtu/hr)	7,538	company report	7,538
Current Emissions (tpy)	16,329	2001 - 2003CAM data	15,183
Current Emissions (lb/mmBtu)	0.57	2001 - 2003CAM data	0.56
Current Uncontrolled Emissions (tpy)	16,329	2001 - 2003CAM data	15,183
Current Control Efficiency	0%	company report	0%
Company Cost-benefit Analysis			
Future Uncontrolled Emissions (tpy)	24,893	company report	24,893
Controlled Emissions (lb/mmBtu)	0.15	company report	0.15
Overall Control Efficiency (FGD)	74%	calculated	73%
Controlled emissions (tpy)	4,985	calculated	4,985
Emission Reductions (tpy)	19,908	company report	19,908
Capital Cost	$ 490,796,000	company report	$ 490,796,000
Capital Cost ($/kW)	$ 738	calculated	$ 701
O&M Cost			
Annualized Cost	$ 54,258,500	company report	$ 54,258,500
Cost-Effectiveness ($/ton)	$ 2,726	company report	$ 2,726

Although we were unable to estimate operating costs, and thus total annual costs and cost-per-ton, due to a lack of information from NPPD, we were able to estimate capital costs based upon Section 5 of the Cost Manual.[12]

[12] Our calculations are contained in the attached Excel workbook and in Appendix C.

Table 5.b. Gerald Gentleman — NPS estimates **Dry FGD addition burning PRB sub-bituminous**

Unit	#1	Source	#2
Rating (MW Gross) each	665	company report	700
Rating (mmBtu/hr)	7,538	company report	7,538
Current Emissions (tpy)	16,329	2001 - 2003CAM data	15,183
Current Emissions (lb/mmBtu)	0.57	2001 - 2003CAM data	0.56
Current Uncontrolled Emissions (tpy)	16,329	2001 - 2003CAM data	15,183
Current Control Efficiency	0%	company report	0%
NPS Cost-benefit Analysis			
Future Uncontrolled Emissions (tpy)	24,893	2001 - 2003CAM data	24,893
Controlled Emissions (lb/mmBtu)	0.06	calculated	0.06
Overall Control Efficiency (FGD)	90%	NPS estimate	90%
Controlled emissions (tpy)	2,489	calculated	2,489
Emission Reductions (tpy)	22,403	calculated	22,403
Capital Cost	$ 261,514,440	calculated	$ 261,514,440
Capital Cost ($/kW)	$ 393	calculated	$ 374

Even when we include NPPD's high costs for ductwork, stack, and baghouse modifications, our estimates of $374 - $393/kWh appear much more reasonable than those of NPPD.

We estimate that a 90% reduction in SO_2 at GGS would improve visibility by 0.88 dv at Badlands NP, but we did not have sufficient data to evaluate the cumulative benefits of improving visibility at the other Class I areas.

Wet Scrubber: As shown in Table 6.a. (below), NPPD has estimated that it would cost over $2,700/ton to control SO_2 using a wet scrubber at GGS. Once again, NPPD estimates a capital cost/kWh of over $700. And, again, this appears unusually high, especially when compared to the $335 - $496/kWh that Basin Electric Power proposes to spend to add wet scrubbers to its Leland Olds Units #1 & #2 in North Dakota. Also in North Dakota, Minnkota Power is proposing to add a wet scrubber to its M.R. Young Unit #1 at a capital cost of $435/kWh.

Table 6.a. GGS —NPPD estimates **Wet FGD addition burning PRB sub-bituminous**

Unit	#1	Source	#2
Rating (MW Gross) each	665	company report	700
Rating (mmBtu/hr)	7,538	company report	7,538
Current Emissions (tpy)	16,329	2001 - 2003CAM data	15,183
Current Emissions (lb/mmBtu)	0.57	2001 - 2003CAM data	0.56
Current Uncontrolled Emissions (tpy)	16,329	2001 - 2003CAM data	15,183
Current Control Efficiency	0%	company report	0%
Company Cost-benefit Analysis			
Future Uncontrolled Emissions (tpy)	24,893	company report	24,893
Controlled Emissions (lb/mmBtu)	0.15	company report	0.15
Overall Control Efficiency (FGD)	74%	calculated	73%
Controlled emissions (tpy)	4,985	calculated	4,985
Emission Reductions (tpy)	19,908	company report	19,908
Capital Cost	$ 514,909,500	company report	$ 514,909,500
Capital Cost ($/kW)	$ 774	calculated	$ 736
O&M Cost			
Annualized Cost	$ 54,225,000	company report	$ 54,225,000
Cost-Effectiveness ($/ton)	$ 2,724	company report	$ 2,724

Although we were again unable to estimate operating costs, and thus total annual costs and cost-per-ton, due to a lack of information from NPPD, we were able to estimate capital costs based upon Section 5 of the Cost Manual.[13]

Table 6.b. GGS —NPS estimates **Wet FGD addition burning PRB sub-bituminous**

Unit	#1	Source	#2
Rating (MW Gross) each	665	company report	700
Rating (mmBtu/hr)	7,538	company report	7,538
Current Emissions (tpy)	16,329	2001 - 2003CAM data	15,183
Current Emissions (lb/mmBtu)	0.57	2001 - 2003CAM data	0.56
Current Uncontrolled Emissions (tpy)	16,329	2001 - 2003CAM data	15,183
Current Control Efficiency	0%	company report	0%
NPS Cost-benefit Analysis			
Future Uncontrolled Emissions (tpy)	24,893	2001 - 2003CAM data	24,893
Controlled Emissions (lb/mmBtu)	0.04	NPS estimate	0.04
Overall Control Efficiency (FGD)	93.6%	NPS estimate	93.6%
Controlled emissions (tpy)	1,591	NPS estimate	1,591
Emission Reductions (tpy)	23,302	NPS estimate	23,302
Capital Cost	$ 257,765,112	NPS estimate	$ 257,765,112
Capital Cost ($/kW)	$ 388	NPS estimate	$ 368

[13] Our calculations are contained in the attached Excel workbook and in Appendix C.

Our capital cost estimates of \$368 - \$388/kWh appear much more reasonable than those of NPPD.

We estimate that a 93.6% reduction in SO_2 at GGS would improve visibility by 0.91 dv at Badlands NP, but we did not have sufficient data to evaluate the cumulative benefits of improving visibility at the other Class I areas.

SO_2 BART Conclusions:

Use of EPA guidance and data results in capital cost estimates that are significantly lower than those presented by NPPD. NPPD should re-do its scrubbing analyses in the format presented by the OAQPS Control Cost Manual[14] and model the effects on all Class I areas of reducing SO_2 to 0.04 – 0.06 lb/mmBtu to provide the information to develop the "fifth factor" in the BART process.

We have presented information showing that several EGUs are operating at, or have been proposed or permitted with much lower SO_2 limits than evaluated by NPPD. NPPD should evaluate a SO_2 limit that reflects the capabilities of modern scrubbers. For example, we submitted similar comments to OR DEQ in January 2008 and OR DEQ responded by determining that the Boardman power plant should install a dry scrubber and achieve 0.12 lb/mmBtu by January 1, 2015, at a cost of \$3,055 per ton of SO_2 removed. We recommend that NDEQ consider the actions of OR DEQ and re-evaluate scrubbing at GGS in that context.

[14] It would be very helpful if NPPD would provide vendor quotes and supporting documentation for major cost items.

Omaha Public Power District (OPPD)
Nebraska City Station Unit #1 (NCS)

This facility contains one operating 650 MW coal-fired (Powder River Basin coal) boiler with a second 660 MW coal-fired boiler currently under construction. It appears that facility, as now permitted, is considered a 750 MW or greater power plant and is required to meet the presumptive emission limits for emission units found in the BART Guidelines[1]. The status of the plant capacity should be resolved by communication between the State and U.S. EPA.

OPPD proposes to meet the NO_x presumptive emission limit of 0.23 lb/MMBtu by installing retrofitted Low Nitrogen Oxide (Low- NO_x) combustion control technology "as necessary" to complement the existing overfire air system at an estimated cost of $166/ton (see OPPD Table 5) and $5.4 million/deciview (see OPPD Table 9). OPPD proposes no additional NOx, or SO_2 or PM BART controls. Respectively, the reasons for no additional controls were excessive cost per deciview for SCR for NO_x, excessive cost per deciview for spray dryer absorber (SDA) scrubber for SO_2 and "negligible impact" for particulate matter.

In section 2.1.3, OPPD states that the cost of materials is rising so rapidly that cost estimates may be too low. It seems that they attempted to reflect this in Appendix A where project costs are outlined, by adding an arbitrary "contingency" cost of 25% to the calculated costs. This adjustment was not explained or justified and seemed to unreasonably expand estimated costs. For example, the OPPD cost estimate for an SDA scrubber and filter baghouse is $1,759/ton, but without the 25% contingency the cost may be closer to $1,319/ton. Either cost falls within a reasonable BART range.

Page 7 indicates that cost estimates were developed following guidance provided in the January 2002 OAQPS Control Cost Manual, using "limited vendor data obtained from various vendors in 2003" and then "scaled-up" to the present. In an effort to make OPPD's results for a SDA scrubber comparable to the universe of other companies' BART determinations it would be instructive to recalculate the numbers based strictly on use of the OAQPS Control Cost Manual.

Section 2.2.1 correctly states that all of the flue gas desulfurization technologies can achieve SO_2 removal efficiencies of 90 to 95%. However, in costing the selected SO_2 control technology, an SDA scrubber, a removal efficiency of only 81.6% was used (see Table 2). The discrepancy should be explained or a more realistic removal efficiency should be used. In addition, several regenerative FGD processes are identified in Section 2.2.1, but none were subjected to BART steps 2 (technical feasibility) or 3 (evaluating control effectiveness). Each of these control technologies must be evaluated.

Section 2.5 evaluates visibility impacts by incrementally adding emission controls to arrive at an additive deciview impact as each pollutant is added. However, the visibility improvement of *each* pollutant control should be evaluated individually so that the cost of visibility improvement (e.g., cost per deciview improvement) from a given control technology can be compared to the universe of similar controls in all other BART analyses (as OPPD did in Table 10) in an effort to judge reasonableness. OPPD should evaluate the visibility improvement efficiency of SDA for SO_2 and SCR for NO_x separately.

Section 3.1 attempts to make a case that certain visibility improvements are "well below the minimum perceptible dV change". It is incorrect to dismiss a control strategy on the basis that the resulting improvement is not perceptible or significant. EPA states in the preamble to its BART Guidelines[2] that, "Even though the visibility improvement from an individual source may not be perceptible, it should still be considered in setting BART because the contribution to haze may be significant relative to other source contributions in the Class I areas. Thus, we disagree that the degree of impairment should be contingent upon perceptibility. Failing to consider less-than-perceptible contributions to visibility impairment would ignore the CAA's intent to have BART requirements apply to sources that contribute to, as well as cause, such impairment." However, it is recognized that a minimal deciview change can lead to objective documentation of excessive cost per deciview of visibility improvement which is a legitimate argument.

Taking into account the results obtained (particularly for a SDA scrubber for SO_2 control) by reflecting the above procedural changes in the OPPD BART determination may result in a reasonable cost per deciview improvement in addition to the already-acceptable cost per ton for SO_2 control.

Particulate matter controls were dismissed on the basis of "negligible impact" of PM. However, relatively inexpensive improvements/upgrades on the existing electrostatic precipitator should have been considered and only dismissed upon a showing of excessive cost.

[1] See 40 CFR Part 51, Appendix Y. The U.S. Environmental Protection Agency finalized it's BART Guidelines on June 15, 2005, and published the preamble and final rule text in the Federal Register on July 6, 2005. The rulemaking action added Appendix Y to Part 51, titled "Guidelines for BART Determinations Under the Regional Haze Rule." See Section IV.E.5.

[2] Ibid, see Preamble, 70FR30129, middle column.

Figure 1.a. NPPD-Gerald Gentleman SO2 Rate

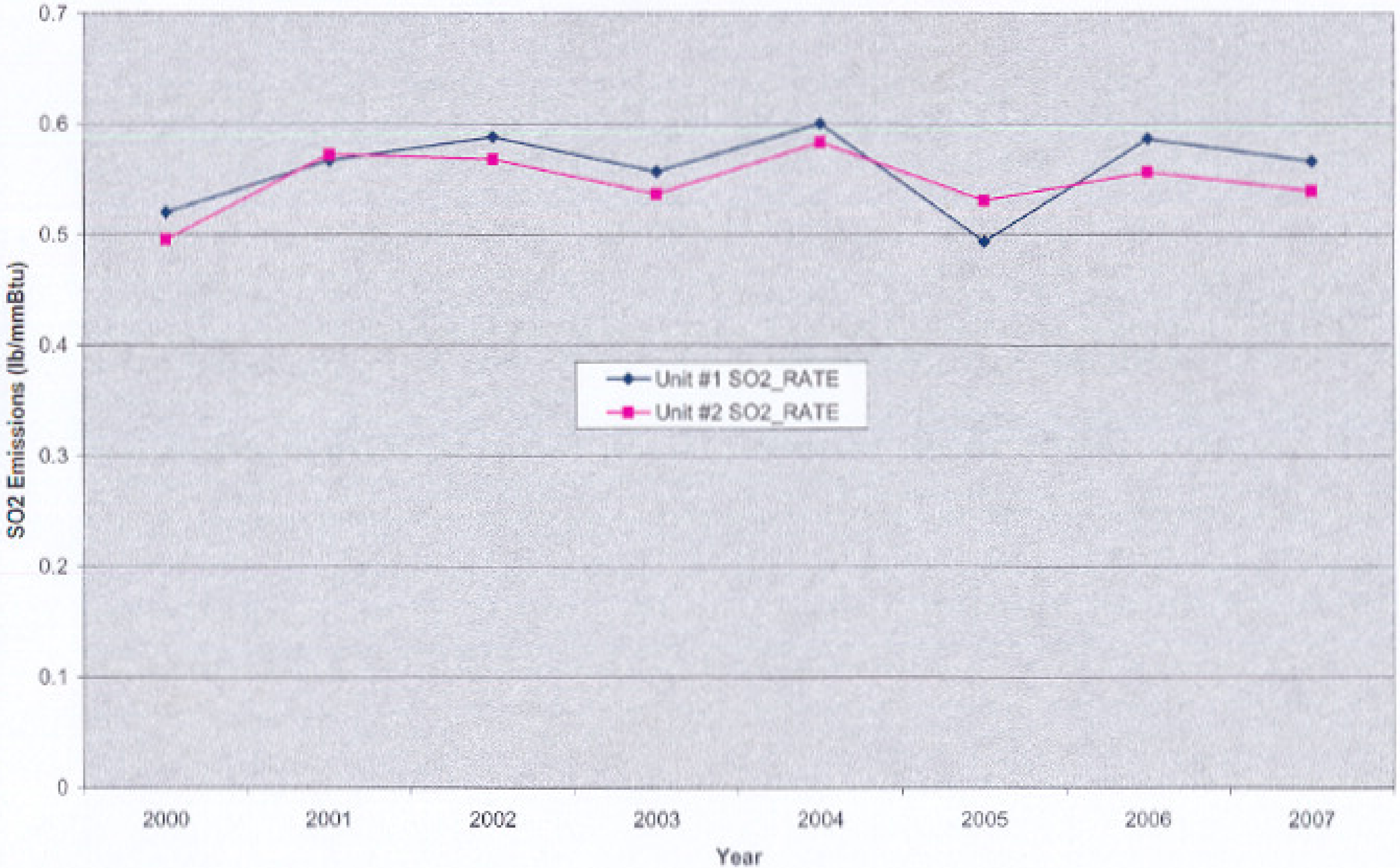


Figure 1.b. NPPD-Gerald Gentleman SO2 Mass

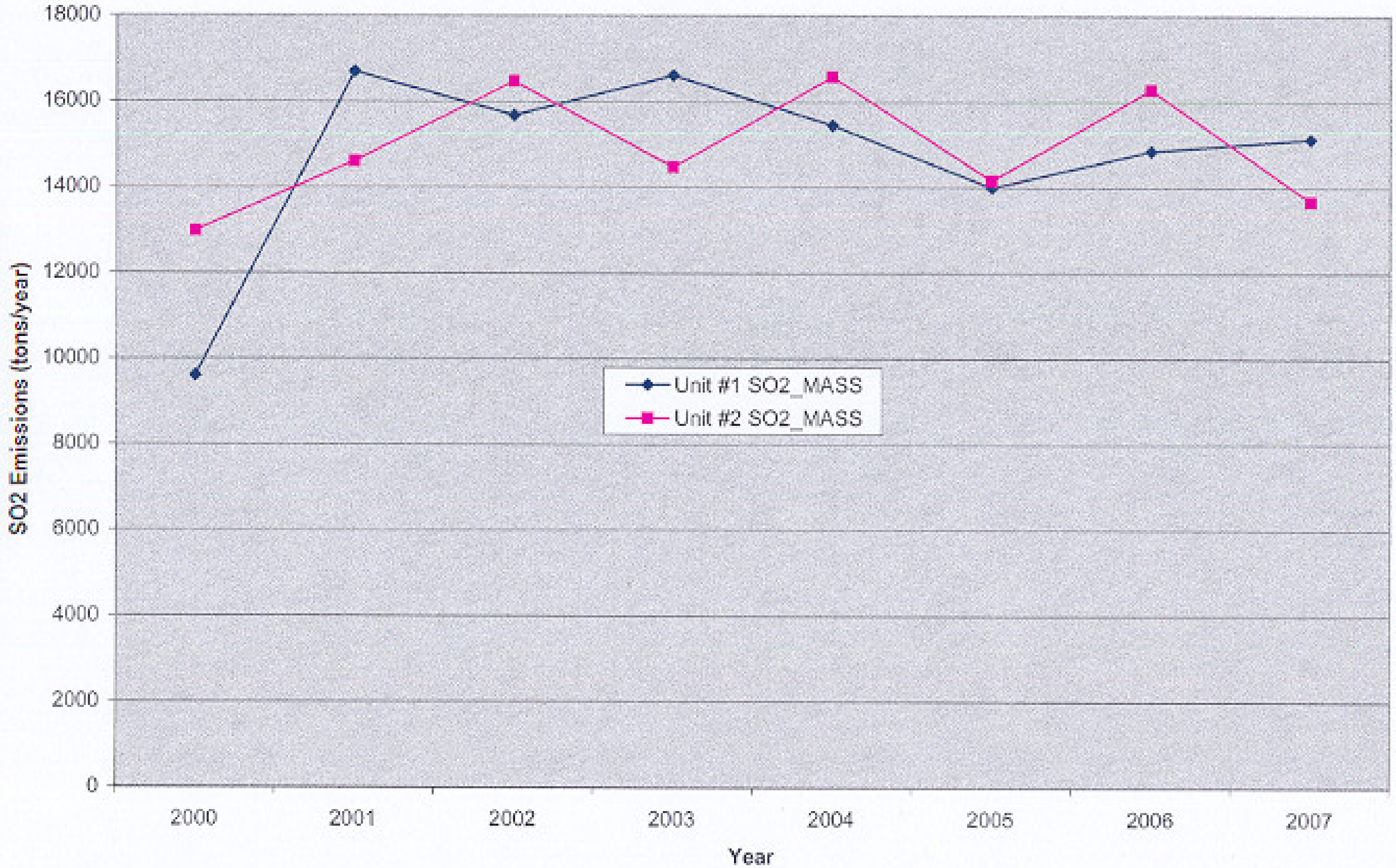


Figure 1.c. NPPD-Gerald Gentleman NOx Rate

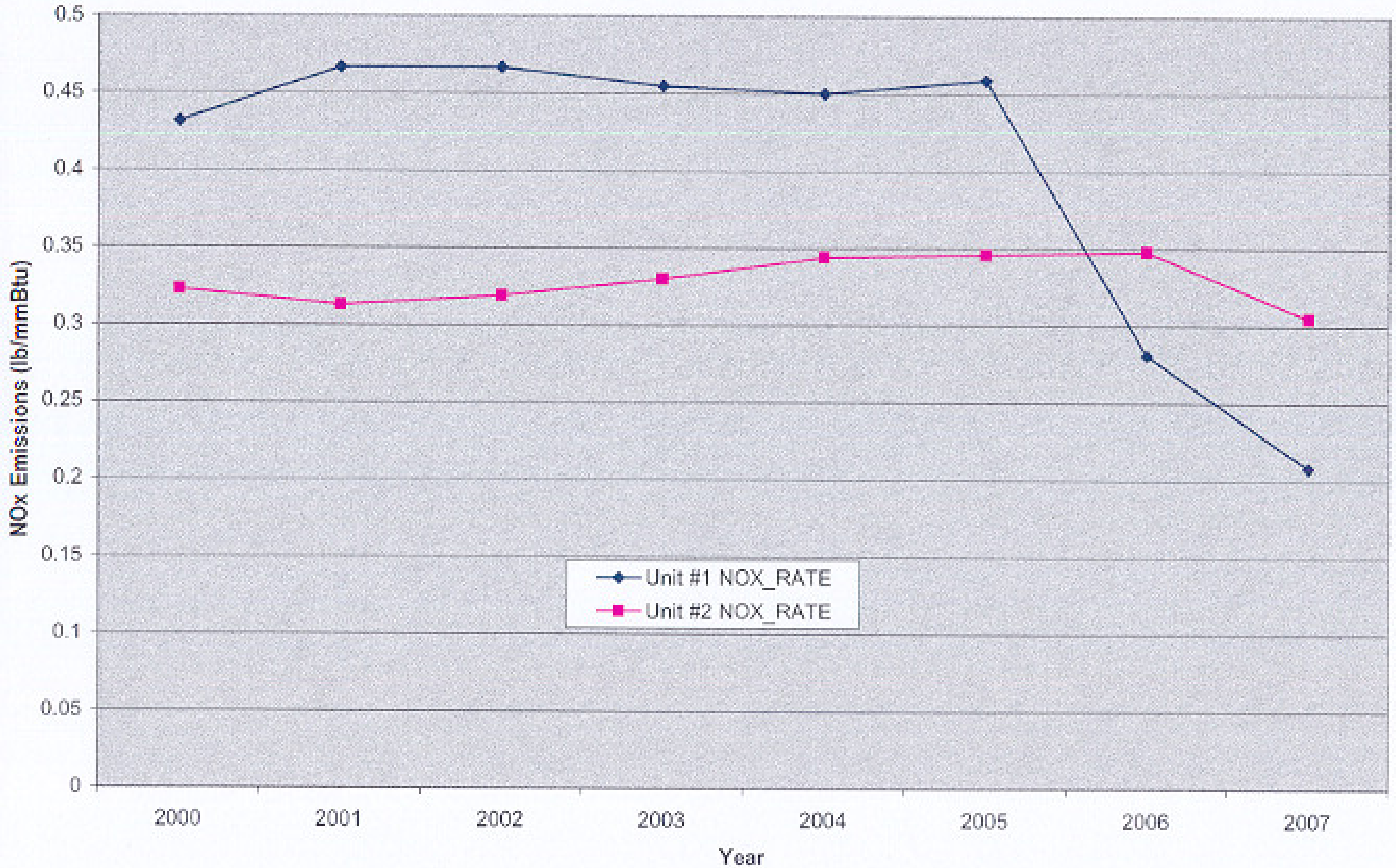


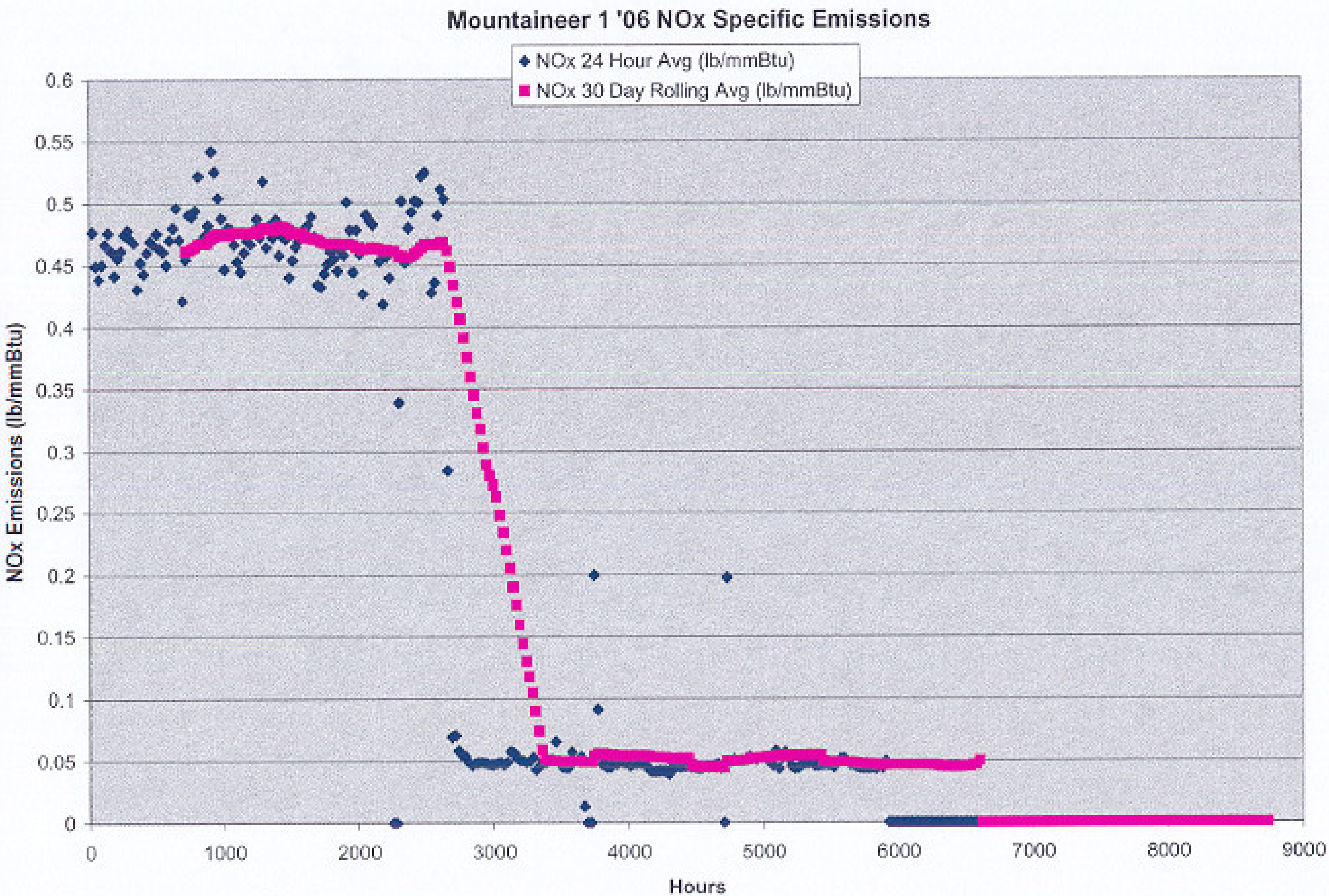
Figure 1.d. NPPD-Gerald Gentleman NOx Mass

Table 2. 2006 CAM Data

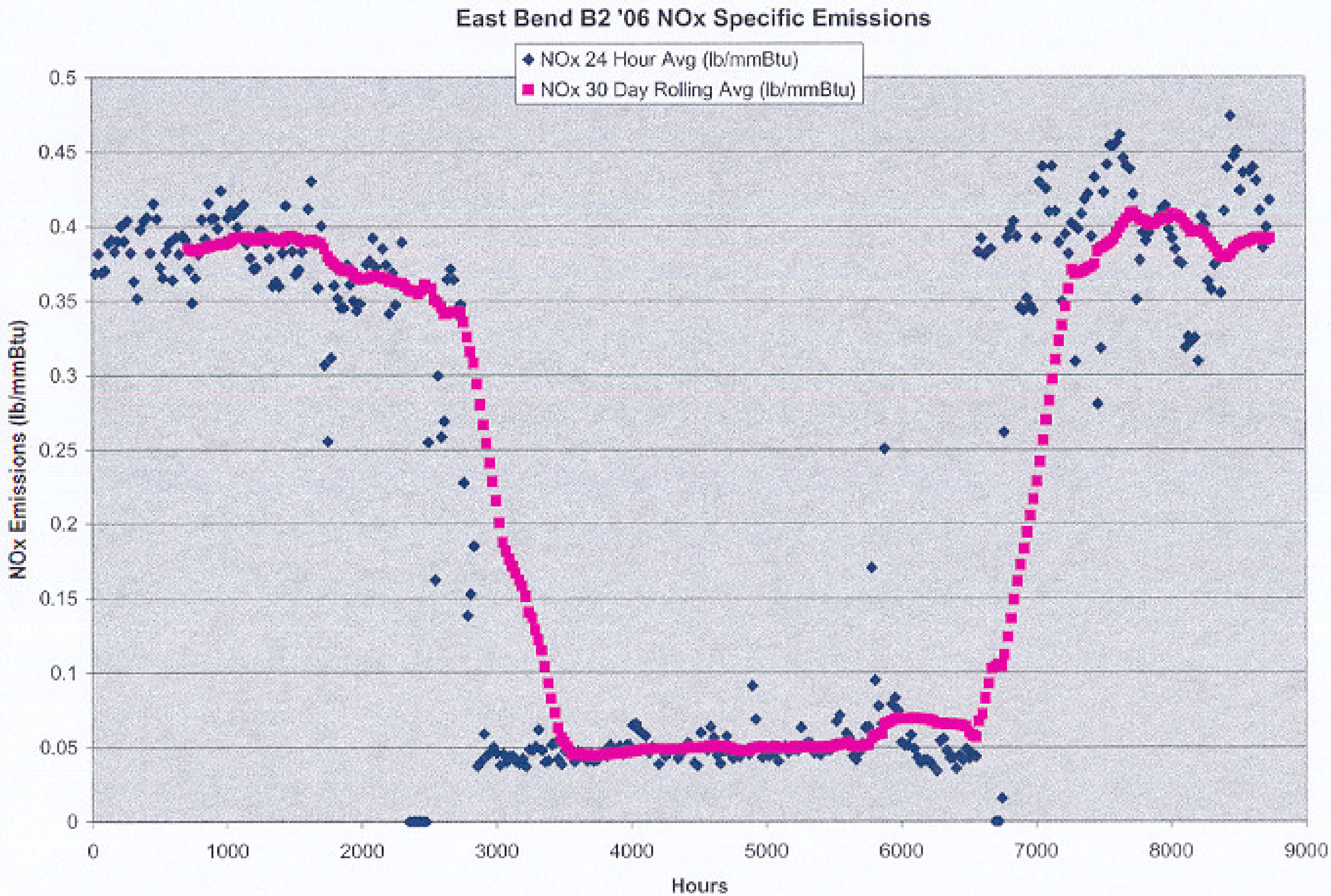
STATE	FACILITY NAME	ORISPL CODE	UNIT ID	UNIT_TYPE_INFO	PRIMARY FUEL	SO2 CONTROL	NOX_CONTROL_INFO	NOX RATE	NOX MASS	HEAT INPUT
OH	Cardinal	2828	1	Cell burner boiler	Coal		Low NOx Cell Burner Selective Non-catalytic Reduction Selective Catalytic Reduction	0.045	125	5,659,992
OH	Cardinal	2828	2	Cell burner boiler	Coal		Low NOx Cell Burner Selective Catalytic Reduction	0.045	134	6,005,564
OH	Miami Fort Generating Station	2832	7	Cell burner boiler	Coal		Low NOx Cell Burner Selective Catalytic Reduction	0.046	393	18,716,545
NC	Belews Creek	8042	2	Cell burner boiler	Coal		Low NOx Cell Burner Overfire Air Selective Catalytic Reduction	0.059	459	16,087,057
IL	Baldwin Energy Complex	889	1	Cyclone boiler	Coal		Overfire Air Selective Catalytic Reduction	0.041	262	13,236,566
IL	Baldwin Energy Complex	889	2	Cyclone boiler	Coal		Overfire Air Selective Catalytic Reduction	0.041	206	13,671,694
TN	Allen	3393	1	Cyclone boiler	Coal		Overfire Air Selective Catalytic Reduction	0.051	740	29,264,079
AL	Colbert	47	5	Dry bottom wall-fired boiler	Coal		Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction	0.031	186	12,802,812
KY	Ghent	1356	3	Dry bottom wall-fired boiler	Coal		Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction	0.043	599	28,256,121
KY	Ghent	1356	4	Dry bottom wall-fired boiler	Coal		Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction	0.043	180	9,120,737
KY	Mill Creek	1364	3	Dry bottom wall-fired boiler	Coal	Wet Limestone	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction	0.044	321	15,651,164
KY	Mill Creek	1364	4	Dry bottom wall-fired boiler	Coal	Wet Limestone	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction	0.045	345	15,970,885
OH	Cardinal	2828	3	Dry bottom wall-fired boiler	Coal		Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction	0.045	135	6,082,829
OH	Miami Fort Generating Station	2832	8	Dry bottom wall-fired boiler	Coal		Selective Catalytic Reduction Low NOx Burner Technology (Dry Bottom only)	0.048	284	12,815,966
SC	Wateree	3297	WAT2	Dry bottom wall-fired boiler	Coal		Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction	0.050	788	32,484,784
VA	Chesapeake Energy Center	3803	3	Dry bottom wall-fired boiler	Coal		Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction	0.055	805	29,501,356
WV	John E Amos	3935	1	Dry bottom wall-fired boiler	Coal		Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction	0.056	493	18,784,984
WV	John E Amos	3935	2	Dry bottom wall-fired boiler	Coal		Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction	0.056	365	13,024,438
WV	Pleasants Power Station	6004	1	Dry bottom wall-fired boiler	Coal	Wet Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction	0.056	791	31,461,836
WV	Pleasants Power Station	6004	2	Dry bottom wall-fired boiler	Coal	Wet Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction	0.057	337	12,620,473
KY	East Bend	6018	2	Dry bottom wall-fired boiler	Coal	Wet Lime FGD	Selective Catalytic Reduction Overfire Air	0.057	247	8,884,727
WV	Mountaineer (1301)	6264	1	Dry bottom wall-fired boiler	Coal		Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction	0.058	555	19,891,173
KY	D B Wilson	6823	W1	Dry bottom wall-fired boiler	Coal	Wet Limestone	Selective Catalytic Reduction Low NOx Burner Technology (Dry Bottom only)	0.058	565	20,449,998
AL	Widows Creek	50	8	Tangentially-fired	Coal	Wet Limestone	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction	0.031	73	4,687,571
GA	Bowen	703	1BLR	Tangentially-fired	Coal		Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction	0.031	301	20,051,368
GA	Bowen	703	2BLR	Tangentially-fired	Coal		Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction	0.032	206	13,757,234
GA	Bowen	703	3BLR	Tangentially-fired	Coal		Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction	0.032	353	22,577,145
GA	Bowen	703	4BLR	Tangentially-fired	Coal		Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction	0.033	295	19,843,875
KY	Ghent	1356	1	Tangentially-fired	Coal	Wet Limestone	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction	0.042	102	6,056,137
NC	Cliffside	2721	5	Tangentially-fired	Coal		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction	0.045	136	6,093,102
PA	Keystone	3136	1	Tangentially-fired	Coal		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction	0.048	344	15,017,671
PA	Montour	3149	1	Tangentially-fired	Coal		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction	0.049	320	14,435,985
PA	Montour	3149	2	Tangentially-fired	Coal		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction	0.049	406	17,282,517
TN	Kingston	3407	1	Tangentially-fired	Coal		Selective Catalytic Reduction	0.052	110	4,257,135
TN	Kingston	3407	2	Tangentially-fired	Coal		Selective Catalytic Reduction	0.052	103	4,435,192
TN	Kingston	3407	3	Tangentially-fired	Coal		Selective Catalytic Reduction	0.052	510	19,752,267
TN	Kingston	3407	4	Tangentially-fired	Coal		Selective Catalytic Reduction	0.052	746	29,102,510
TN	Kingston	3407	5	Tangentially-fired	Coal		Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction	0.053	288	13,354,017
TN	Kingston	3407	6	Tangentially-fired	Coal		Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction	0.053	116	4,392,810
TN	Kingston	3407	7	Tangentially-fired	Coal		Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction	0.053	116	4,372,272
TN	Kingston	3407	8	Tangentially-fired	Coal		Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction	0.053	122	4,645,364
TN	Kingston	3407	9	Tangentially-fired	Coal		Selective Catalytic Reduction	0.053	160	6,131,719
VA	Chesterfield Power Station	3797	4	Tangentially-fired	Coal		Selective Catalytic Reduction Other	0.054	621	23,017,172
VA	Chesterfield Power Station	3797	5	Tangentially-fired	Coal		Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction	0.054	254	9,742,832
VA	Chesterfield Power Station	3797	6	Tangentially-fired	Coal		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction	0.055	577	21,181,336
VA	Chesapeake Energy Center	3803	4	Tangentially-fired	Coal		Selective Catalytic Reduction	0.055	435	16,635,433
GA	Wansley (6052)	6052	1	Tangentially-fired	Coal		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction	0.058	798	28,192,896
GA	Wansley (6052)	6052	2	Tangentially-fired	Coal		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction	0.058	428	16,403,068

Appendix A

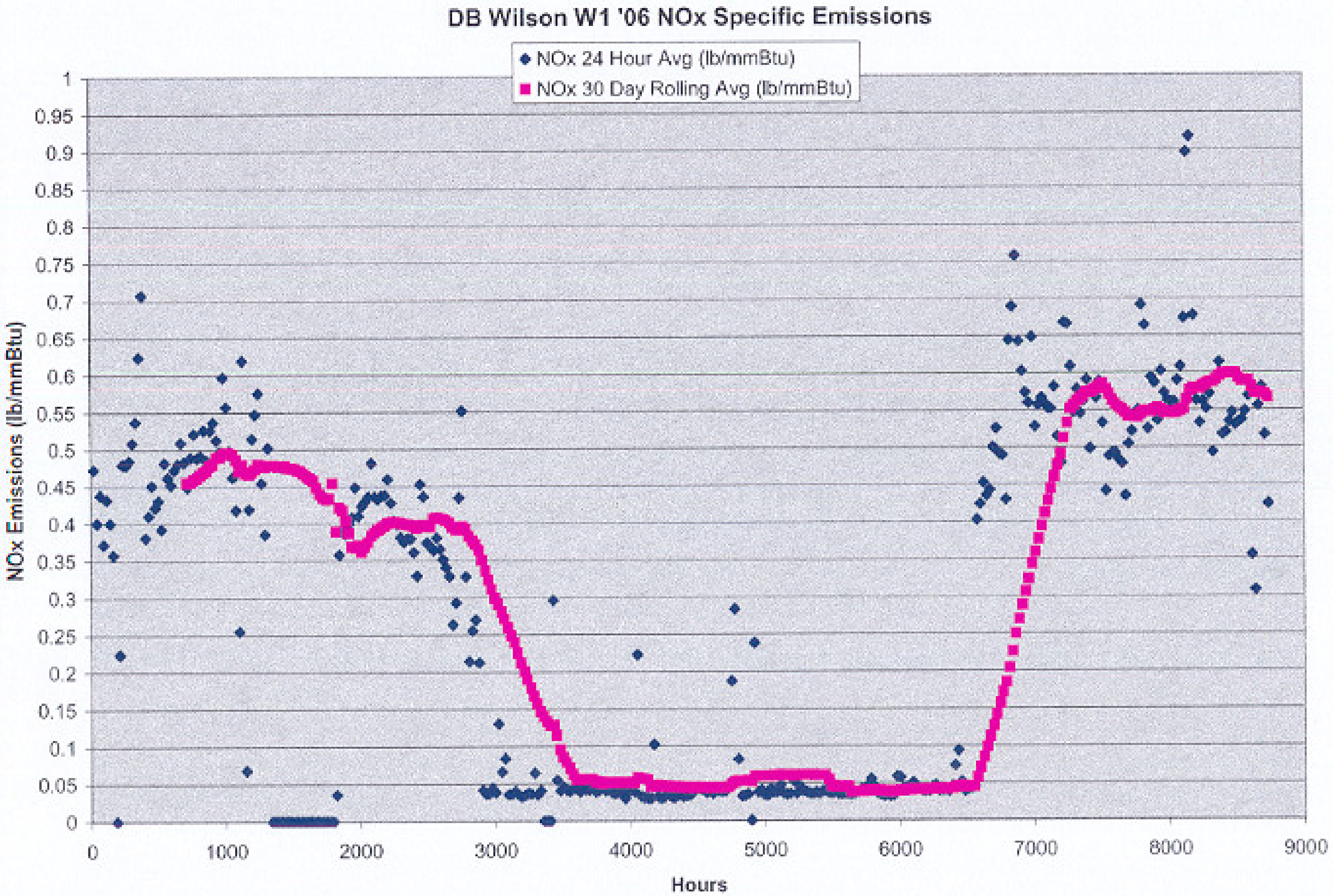
Eastern EGUs with SCR



Mountaineer 1 '06 NOx Specific Emissions
NOx 24 Hour Avg (lb/mmBtu)
NOx 30 Day Rolling Avg (lb/mmBtu)
NOx Emissions (lb/mmBtu)
0.6
0.55
0.5
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
Hours



East Bend B2 '06 NOx Specific Emissions
NOx 24 Hour Avg (lb/mmBtu)
NOx 30 Day Rolling Avg (lb/mmBtu)
NOx Emissions (lb/mmBtu)
0.5
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
Hours



DB Wilson W1 '06 NOx Specific Emissions
NOx 24 Hour Avg (lb/mmBtu)
NOx 30 Day Rolling Avg (lb/mmBtu)
NOx Emissions (lb/mmBtu)
1
0.95
0.9
0.85
0.8
0.75
0.7
0.65
0.6
0.55
0.5
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
Hours

Appendix B

NPS Version of OAQPS Cost Manual for SCR for GGS Unit # 1

Given/Assumptions

New or Retrofit?	Retrofit	
Generation capacity (MW)	665	
SCR bypass included?	No	
Fuel High Heating Value (Btu/lb)	**8,576**	**from EIA 2001**
Maximum Fuel Consumption Rate (lb/hr)	6.5E+05	**NPS estimate**
Average Annual Fuel Consumption (lb)	**5.71E+09**	**from EIA 2001**
Number of SCR Operating Days	365	
Plant Capacity Factor	69%	**Cost Tool**
Uncontrolled NOx Concentration (lb/mmBtu)	**0.46**	**annual average from CAM data**
Uncontrolled NOx Emissions (tpy)	**15,122**	**company report**
LNB + OFA Total Capital Cost	**$ 18,465,000**	**company report**
LNB + OFA Total Annual Cost	**$ 1,480,000**	**company report**
LNB outlet = SCR inlet NOx Concentration (lb/mmBtu)	**0.23**	**presumptive BART**
Required Controlled NOx Concentration (lb/mmBtu)	**0.05**	**NPS estimate**
Acceptable Ammonia Slip (ppm)	2.0	OAQPS Control Cost Manual
Fuel Volume Flow Rate (ft3/min/mmBtu/hr)	547	OAQPS Control Cost Manual
Fuel Heating Value (Btu/lb)	**8,576**	**from EIA 2001**
Fuel Sulfur Content	**0.30%**	**from EIA 2001**
Fuel Ash Content	**4.69%**	**from EIA 2001**
Number of SCR reactor chambers	1	OAQPS Control Cost Manual
ASR	1.05	OAQPS Control Cost Manual
Stored Ammonia Concentration	29%	OAQPS Control Cost Manual
Reagent Molecular Weight (g/mole)	17.03	OAQPS Control Cost Manual
Reagent Density (lb/ft3 @ 60F)	56.0	OAQPS Control Cost Manual
Reagent Specific Volume (gal/ft3)	7.481	OAQPS Control Cost Manual
NOx Molecular Weight (g/mole)	46.01	OAQPS Control Cost Manual
Number of Days of Storage for Ammonia	14	OAQPS Control Cost Manual
Pressure Drop for SCR Ductwork H2O")	3	OAQPS Control Cost Manual
Pressure Drop for each Catalyst Layer (H2O")	1	OAQPS Control Cost Manual
Temperature at SCR Inlet (degrees F)	650	OAQPS Control Cost Manual
Equipment Life (years)	20	OAQPS Control Cost Manual
Annual Interest Rate	7%	OAQPS Control Cost Manual
Inflation Since 1998	1.28	CPI
Catalyst Cost, Initial ($/ft3)	240	OAQPS Control Cost Manual
Catalyst Cost, Replacement ($/ft3)	290	OAQPS Control Cost Manual
Electrical Power Cost ($/kWh)	0.05	OAQPS Control Cost Manual
29% Ammonia Solution Cost ($/lb)	0.101	OAQPS Control Cost Manual
Operating Life of Catalyst (hours)	24,000	OAQPS Control Cost Manual

Uncontrolled NOx emissions (tpy) **15,122**

LNB Control Efficiency = (Inlet Conc - Outlet Conc)/Inlet conc

(0.46 - 0.23)/ 0.46 = 50%

Boiler Calculations

2.3 $Q_B = HVm\text{-}dot_{fuel}$

QB = 8576 Btu/lb * 651,484 lb/hr

QB = **5,587** mmBtu/hr

2.7 CF_{Plant} = actual m_{fuel}/maximum m_{fuel}

CFPlant = 5.71E+09 lb/yr / 8760 hr/yr / 651,484 lb/hr

CFPlant = 100%

2.8 $CF_{SCR} = t_{SCR}/365$ days

CFSCR = 365 days/ 365 days

CFSCR = 100%

$CF_{Total} = CF_{Plant} \times CF_{SCR}$

CFTotal = 100% * 100%

CFTotal = 69% from Given/Assume

2.12 $q_{fluegas} = q_{fuel}Q_B(460+T)/(460+700^{o}F)n_{SCR}$

qfluegas = 547 ft3/min/(mmBtu/hr)* 5587 mmBtu/hr*(460 + 650)/(460 + 700)* 1

qfluegas = 2,924,427 acfm

2.9 $\eta_{NOx} = (NOx_{in} - NOx_{out}) / NOx_{in}$

ηNOx = (0.23 lb/mmBtu - 0.05 lb/mmBtu)/ 0.23 lb/mmBtu

ηNOx = **78%** **Modern NOx controls can achieve 90% NOx reduction.**

Overall Control Efficiency = (Inlet Conc - Outlet Conc)/Inlet conc

(0.46 - 0.05)/ 0.46 = 89%

NOx removed = 13,489 tpy

Controlled NOx emissions (tpy) = 1,633 tpy

SCR Reactor Calculations

2.19 $Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NOx_{adj} \times S_{adj} \times T_{adj}/N_{SCR}$

Volcatalyst = 2.81 * 5587 = 15700

2.2 $\eta_{adj} = 0.2869 + (1.058 \times \eta)$

ηadj = 0.2869 +(1.058 * 0.78)
ηadj = 1.115

2.22 $Slip_{adj} = 1.2835 - (0.0567 \times Slip)$

Slipadj = 1.2835 - (0.057 * 2)
Slipadj = 1.170

2.21 $NOx_{adj} = 0.8524 + (0.3208 \times NOx_{in})$

NOxadj = 0.8524 + (0.321 * 0.23)
NOxadj = 0.926

2.23 $S_{adj} = 0.9636 + (0.0455 \times S)$

Sadj = 0.9636 + (0.046 * 0.3)
Sadj = 0.977

2.24 $T_{adj} = 15.16 - (0.03937 \times T) + (2.74 \times 10^{-5} \times T^2)$

Tadj = 15.16 - (0.039 * 650) + 2.74E-05 * 422500
Tadj = 1.146

Volcatalyst = 21,244 ft3

2.25 $A_{catalyst} = q_{fluegas}/(16 \text{ ft/sec} \times 60 \text{ sec/min})$

Acatalyst = 2924427 /(16 * 60)
Acatalyst = 3046 ft2

2.26 $A_{SCR} = 1.15 \times A_{catalyst}$

ASCR = 1.15 * 3046
ASCR = 3503 ft2

2.27 $l = w = A_{SCR}^{1/2}$

l = w = 59.2 ft

2.28 $n_{layer} = Vol_{catalyst}/(h'_{layer} \times A_{catalyst})$

nlayer = 21244 /(3.1 * 3046)
nlayer = 2.0

2.29 $h_{layer} = [Vol_{catalyst}/(n_{layer} \times A_{catalyst})] + 1$

hlayer = 21244 /(3 * 3046) + 1
hlayer = 3.3

2.3 $n_{total} = n_{layer} + n_{empty}$

ntotal = 2 + 1
ntotal = 3

2.31 $h_{SCR} = n_{total}(c_1 + h_{layer}r) + c_2$

hSCR = 3 * (7 + 3.3) + 9
hSCR = 40 ft

Reagent Calculations

2.32 $\dot{m}$-dot: $\text{m-dot}_{reagent} = NOx_{in} Q_B ASR \eta_{NOx} M_{reagent} / M_{NOx}$

m-dotreagent =	0.23 *	5587 *	1.05 *	**78%** *	17.03 /	46.01
m-dotreagent =	391 lb/hr					

2.33 $\text{m-dot}_{sol} = \text{m-dot}_{reagent} / C_{sol}$

m-dotsol =	391 /	0.29
m-dotsol =	1348 lb/hr	

2.34 $q_{sol} = (\text{m-dot}_{vol} / \rho_{sol}) V_{sol}$

qsol =	1348 *	7.481 /	56
qsol =	180 gph		

2.35 $\text{Tank Volume} = q_{sol} t$

Tank Volume =	180 *	14 *	24
Tank Volume =	60,496 gal		

Direct Capital Cost

2.36 $DC = Q_B[(\$3380/MMBtu/hr) + f(h_{SCR}) + f(NH_3rate) + f(new) + f(bypass)](3500/Q_B)^{0.35} + f(Vol_{catalyst})$

DC = 5587 (($ 3,380 +

2.37 $f(h_{SCR}) = \{[\$612/(ft\text{-}mmBtu/hr)]h_{SCR}\} - \$187.9/(mmBtu/hr)$

f(hSCR) = 6.12 * 40 - 187.9

f(hSCR) = $ 57 /mmBtu/hr

2.38 $f(NH_3rate) = [(\$411/lb/hr)(m\text{-}dot_{reagent}/Q_B)] - \$473/(mmBtu/hr)$

f(NH3rate) = 411 * 391 / 5587 - 47.3

f(NH3rate) = $ (19) /mmBtu/hr

2.39 f(new) = $0/(mmBtu/hr) for retrofit

f(new) = $ -

2.41 f(bypass) = $0/(mmBtu/hr) for no bypass

f(bypass) = $ - /mmBtu/hr

2.43 $f(Vol_{catalyst}) = Vol_{catalyst}CCinitial$

f(Volcatalyst) = 21244 * 240

f(Volcatalyst) = $ 5,098,619

DC = 5587 * ($ 3,380 + $ 57 + $ (19) + $ - + $ -)*(3500 / 1000)^ 0.35 + $ 5,098,619

DC = $ 34,706,599

Inflation Adjustment = 1.28

DC = $ 44,424,446

Indirect Capital Costs

Total Direct Capital Costs, A						$ 44,424,446
Indirect Installation Costs						
General Facilities			0.05 A			$2,221,222
Engineering and Home Office Fees			0.10 A			$4,442,445
Process Contingencies			0.05 A			$2,221,222
Total Indirect Installation Costs, B			0.20 A			$8,884,889
Project Contingency, C =			0.15 (A+B)			$7,996,400
Total Plant Cost D =			A+B+C			$61,305,736
Allowance for Funds During Construction, E =			0			$0
Royalty Allowance, F =			0			$0
Preproduction Cost, G =			0.02 (D+E)			$1,226,115
Inventory Capital, H =	0.101 /lb *	1348 lb/r *	24 hr/day *	14 days =		$45,738
Initial Catalyst and Chemicals, I =						$ -
Total Capital Investment TCI = D+G+H			+D+E+F+G+H+I			$62,577,589
Total Capital Investment TCI including LNB + OFA =						$81,042,589

Annual Costs

2.45 DAC = Annual Maintenance Cost + Annual Reagent Cost + Annual Electricity Cost + Annual Water Cost + Annual Catalyst Cost

2.46 Annual Maintenance Cost = 0.015 TCI

Annual Maintenance Cost = 0.015 * $ 62,577,589

Annual Maintenance Cost = $ 938,664

2.47 Annual Reagent Cost = $q_{reagent}Cost_{reagent}t_{op}$

2.47a $t_{op} = CF_{total}8760hr/yr$

top = **69%** * 8760

top = **6044**

Annual Reagent Cost = 1348 * **6044** * 0.101

Annual Reagent Cost = $ 822,791 **SRP estimate frm table E-1 $ 936,000**

2.49 Annual Electricity Cost = Power $(Cost_{elect})t_{op}$

2.48 **Power = $0.105Q_B[NOx_{in}\eta NOxCFtotal + 0.5(\Delta P_{duct} + n_{total}\Delta P_{catalyst})]$**

Power = 0.105 * 5587 *(0.463 * 78% * 69% + 0.5 *(3 + **2** * 1))

Power = 1613 kW

Annual Electricity Cost = 1613 * **6044** * 0.05

Annual Electricity Cost = $ 487,570

2.51 Annual Catalyst Replacement Cost = (Catalyst Replacement Cost)FWF

2.5 Catalyst Replacement Cost = $n_{SCR}Vol_{catalyst}CC_{replace}/R_{layer}$

Catalyst Replacement Cost = 1 * 21244 * 290 / 2

Catalyst Replacement Cost = $ 3,080,416

2.52 FWF = $i\{1/[(1+i)^Y-1]\}$

2.53 Y = $h_{catalyst}/h_{year}$

Y = 24000 / **6044**

Y = 4

FWF = 0.07 *(1 /(1 + 0.07)^ 4.00 - 1)

FWF = 0.23

Annual Catalyst Cost = $ 693,796

DAC = **$ 2,942,821**

2.55 CRF = $i(1+i)^n/[(1+i)^n-1]$

CRF = 0.07 *(1 + 0.07)^ 20 /((1 + 0.07)^ 20 - 1)

CRF = 0.0944

Indirect Annual Cost = CFR * TCI

Indirect Annual Cost = 0.0944 * $ 81,042,589

Indirect Annual Cost = **$ 7,649,847**

2.56 Total Annual Cost = Direct Annual Cost + Indirect Annual Cost

Total Annual Cost = $ 2,942,821 + $ 7,649,847

Total Annual Cost = $ 10,592,668 + $ 1,480,000 for LNB+OFA

Total Annual Cost = $ 12,072,668

2.57 NOx Removed = $NOx_{in}\eta_{NOx}Q_Bt_{op}$

NOx Removed = 0.46 * 89% * 5587 * **6044** / 2000

NOx Removed = 13,489 data from CAM

2.58 Cost effectiveness = TAC/NOx removed

Cost effectiveness = $ 895 / ton

Cost effectiveness = / dv

Appendix B

NPS Version of OAQPS Cost Manual SCR for GGS Unit #2

NPPD - Gerald Gentleman Unit #2

Given/Assumptions

New or Retrofit?	Retrofit	
Generation capacity (MW)	700	
SCR bypass included?	No	
Fuel High Heating Value (Btu/lb)	**8,576**	**from EIA 2001**
Maximum Fuel Consumption Rate (lb/hr)	6.5E+05	**NPS estimate**
Average Annual Fuel Consumption (lb)	**5.71E+09**	**from EIA 2001**
Number of SCR Operating Days	365	
Plant Capacity Factor	62%	**Cost Tool**
Uncontrolled NOx Concentration (lb/mmBtu)	**0.32**	**annual average from CAM data**
Uncontrolled NOx Emissions (tpy)	**15,122**	**company report**
LNB + OFA Total Capital Cost	**$ 18,465,000**	**company report**
LNB + OFA Total Annual Cost	**$ 1,480,000**	**company report**
SCR inlet NOx Concentration (lb/mmBtu)	**0.23**	**presumptive BART**
Required Controlled NOx Concentration (lb/mmBtu)	**0.05**	**NPS estimate**
Acceptable Ammonia Slip (ppm)	2.0	OAQPS Control Cost Manual
Fuel Volume Flow Rate (ft3/min/mmBtu/hr)	547	OAQPS Control Cost Manual
Fuel Heating Value (Btu/lb)	**8,576**	**from EIA 2001**
Fuel Sulfur Content	**0.30%**	**from EIA 2001**
Fuel Ash Content	**4.69%**	**from EIA 2001**
Number of SCR reactor chambers	**1**	OAQPS Control Cost Manual
ASR	1.05	OAQPS Control Cost Manual
Stored Ammonia Concentration	29%	OAQPS Control Cost Manual
Reagent Molecular Weight (g/mole)	17.03	OAQPS Control Cost Manual
Reagent Density (lb/ft3 @ 60F)	56.0	OAQPS Control Cost Manual
Reagent Specific Volume (gal/ft3)	7.481	OAQPS Control Cost Manual
NOx Molecular Weight (g/mole)	46.01	OAQPS Control Cost Manual
Number of Days of Storage for Ammonia	14	OAQPS Control Cost Manual
Pressure Drop for SCR Ductwork H2O")	3	OAQPS Control Cost Manual
Pressure Drop for each Catalyst Layer (H2O")	1	OAQPS Control Cost Manual
Temperature at SCR Inlet (degrees F)	650	OAQPS Control Cost Manual
Equipment Life (years)	20	OAQPS Control Cost Manual
Annual Interest Rate	7%	OAQPS Control Cost Manual
Inflation Since 1998	1.28	CPI
Catalyst Cost, Initial ($/ft3)	240	OAQPS Control Cost Manual
Catalyst Cost, Replacement ($/ft3)	290	OAQPS Control Cost Manual
Electrical Power Cost ($/kWh)	0.05	OAQPS Control Cost Manual
29% Ammonia Solution Cost ($/lb)	0.101	OAQPS Control Cost Manual
Operating Life of Catalyst (hours)	24,000	OAQPS Control Cost Manual

Uncontrolled NOx emissions (tpy) **15,122**

LNB Control Efficiency = (Inlet Conc - Outlet Conc)/Inlet conc

(0.32 - 0.23)/ 0.32 = 28%

Boiler Calculations

2.3 $Q_B = HVm\text{-}dot_{fuel}$

QB =	8576	Btu/lb *	651,484	lb/hr
QB =	**5,587**	mmBtu/hr		

2.7 $CF_{Plant} = \text{actual } m_{fuel}/\text{maximum } m_{fuel}$

CFPlant =	5.71E+09	lb/yr /	8760	hr/yr /	651,484	lb/hr
CFPlant =	100%					

2.8 $CF_{SCR} = t_{SCR}/365 \text{ days}$

CFSCR =	365	days/	365 days
CFSCR =	100%		

$CF_{Total} = CF_{Plant} \times CF_{SCR}$

CFTotal =	100% *	100%
CFTotal =	**62% from Given/Assume**	

2.12 $q_{fluegas} = q_{fuel}Q_B(460+T)/(460+700^{\circ}F)n_{SCR}$

qfluegas = 547 ft3/min/(mmBtu/hr)* 5587 mmBtu/hr*(460 + 650)/(460 + 700)* 1

qfluegas = 2,924,427 acfm

2.9 $\eta_{NOx} = (NOx_{in} - NOx_{out}) / NOx_{in}$

ηNOx = (0.23 lb/mmBtu - 0.05 lb/mmBtu)/ 0.23 lb/mmBtu

ηNOx = **78%** **Modern NOx controls can achieve 90% NOx reduction.**

Overall Control Efficiency = (Inlet Conc - Outlet Conc)/Inlet conc

(0.32 - 0.05)/ 0.32 = 84%

NOx removed = 12,764 tpy

Controlled NOx emissions (tpy) = 2,358 tpy

SCR Reactor Calculations

2.19 $Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NOx_{adj} \times S_{adj} \times T_{adj}/N_{SCR}$

Volcatalyst = 2.81 * 5587 = 15700

2.2 $\eta_{adj} = 0.2869 + (1.058 \times \eta)$

ηadj = 0.2869 +(1.058 * 0.78)
ηadj = 1.115

2.22 $Slip_{adj} = 1.2835 - (0.0567 \times Slip)$

Slipadj = 1.2835 - (0.057 * 2)
Slipadj = 1.170

2.21 $NOx_{adj} = 0.8524 + (0.3208 \times NOx_{in})$

NOxadj = 0.8524 + (0.321 * 0.23)
NOxadj = 0.926

2.23 $S_{adj} = 0.9636 + (0.0455 \times S)$

Sadj = 0.9636 + (0.046 * 0.3)
Sadj = 0.977

2.24 $T_{adj} = 15.16 - (0.03937 \times T) + (2.74 \times 10^{-5} \times T^2)$

Tadj = 15.16 - (0.039 * 650) + 2.74E-05 * 422500
Tadj = 1.146

Volcatalyst = 21,244 ft3

2.25 $A_{catalyst} = q_{fluegas}/(16 \text{ ft/sec} \times 60 \text{ sec/min})$

Acatalyst = 2924427 /(16 * 60)
Acatalyst = 3046 ft2

2.26 $A_{SCR} = 1.15 \times A_{catalyst}$

ASCR = 1.15 * 3046
ASCR = 3503 ft2

2.27 $l = w = A_{SCR}^{1/2}$

l = w = 59.2 ft

2.28 $n_{layer} = Vol_{catalyst}/(h'_{layer} \times A_{catalyst})$

nlayer = 21244 /(3.1 * 3046)
nlayer = 2.0

2.29 $h_{layer} = [Vol_{catalyst}/(n_{layer} \times A_{catalyst})] + 1$

hlayer = 21244 /(3 * 3046) + 1
hlayer = 3.3

2.3 $n_{total} = n_{layer} + n_{empty}$

ntotal = 2 + 1
ntotal = 3

2.31 $h_{SCR} = n_{total}(c_1 + h_{layer}) + c_2$

hSCR = 3 * (7 + 3.3) + 9
hSCR = 40 ft

Reagent Calculations

2.32 $\dot{m}_{reagent} = NOx_{in} Q_B ASR \eta_{NOx} M_{reagent}/M_{NOx}$

m-dotreagent =	0.23 *	5587 *	1.05 *	**78%** *	17.03 /	46.01
m-dotreagent =	391 lb/hr					

2.33 $\dot{m}_{sol} = \dot{m}_{reagent}/C_{sol}$

m-dotsol =	391 /	0.29
m-dotsol =	1348 lb/hr	

2.34 $q_{sol} = (\dot{m}_{vol}/\rho_{sol})V_{sol}$

qsol =	1348 *	7.481 /	56
qsol =	180 gph		

2.35 Tank Volume $= q_{sol}t$

Tank Volume =	180 *	14 *	24
Tank Volume =	60,496 gal		

Direct Capital Cost

2.36 $DC = Q_B[(\$3380/MMBtu/hr) + f(h_{SCR}) + f(NH_3rate) + f(new) + f(bypass)](3500/Q_B)^{0.35} + f(Vol_{catalyst})$

DC = 5587 (($ 3,380 +

2.37 $f(h_{SCR}) = \{[\$612/(ft\text{-}mmBtu/hr)]h_{SCR}\} - \$187.9/(mmBtu/hr)$

f(hSCR) = 6.12 * 40 - 187.9

f(hSCR) = $ 57 /mmBtu/hr

2.38 $f(NH_3rate) = [(\$411/lb/hr)(m\text{-}dot_{reagent}/Q_B)] - \$473/(mmBtu/hr)$

f(NH3rate) = 411 * 391 / 5587 - 47.3

f(NH3rate) = $ (19) /mmBtu/hr

2.39 f(new) = \$0/(mmBtu/hr) for retrofit

f(new) = $ -

2.41 f(bypass) = \$0/(mmBtu/hr) for no bypass

f(bypass) = $ - /mmBtu/hr

2.43 $f(Vol_{catalyst}) = Vol_{catalyst}CCinitial$

f(Volcatalyst) = 21244 * 240

f(Volcatalyst) = $ 5,098,619

DC = 5587 * ($ 3,380 + $ 57 + $ (19) + $ - + $ -)*(3500 / 1000)^ 0.35 + $ 5,098,619

DC = $ 34,706,599

Inflation Adjustment = 1.28

DC = $ 44,424,446

<u>Indirect Capital Costs</u>

Total Direct Capital Costs, A						$ 44,424,446
Indirect Installation Costs						
General Facilities				0.05 A		$2,221,222
Engineering and Home Office Fees				0.10 A		$4,442,445
Process Contingencies				0.05 A		$2,221,222
Total Indirect Installation Costs, B				0.20 A		$8,884,889
Project Contingency, C =				0.15 (A+B)		$7,996,400
Total Plant Cost D =				A+B+C		$61,305,736
Allowance for Funds During Construction, E =				0		$0
Royalty Allowance, F =				0		$0
Preproduction Cost, G =				0.02 (D+E)		$1,226,115
Inventory Capital, H =	0.101 /lb *	1348 lb/r *	24 hr/day *		14 days =	$45,738
Initial Catalyst and Chemicals, I =						$ -
Total Capital Investment TCI = D+G+H				+D+E+F+G+H+I		$62,577,589
Total Capital Investment TCI including LNB + OFA =						$81,042,589

Annual Costs

2.45 DAC = Annual Maintenance Cost + Annual Reagent Cost + Annual Electricity Cost + Annual Water Cost + Annual Catalyst Cost

2.46 Annual Maintenance Cost = 0.015 TCI

Annual Maintenance Cost = 0.015 * $ 62,577,589

Annual Maintenance Cost = $ 938,664

2.47 Annual Reagent Cost = $q_{reagent}Cost_{reagent}t_{op}$

2.47a $t_{op} = CF_{total}8760hr/yr$

top = **62%** * 8760

top = **5431**

Annual Reagent Cost = 1348 * **5431** * 0.101

Annual Reagent Cost = $ 739,319 **SRP estimate frm table E-1 $ 936,000**

2.49 Annual Electricity Cost = Power $(Cost_{elect})t_{op}$

2.48 Power = $0.105Q_B[NOx_{In}\eta NOxCFtotal + 0.5(\Delta P_{duct} + n_{total}\Delta P_{catalyst})]$

Power = 0.105 * 5587 *(0.321 * 78% * 62% + 0.5 *(3 + 2 * 1))

Power = 1558 kW

Annual Electricity Cost = 1558 * **5431** * 0.05

Annual Electricity Cost = $ 423,063

2.51 Annual Catalyst Replacement Cost = (Catalyst Replacement Cost)FWF

2.5 Catalyst Replacement Cost = $n_{SCR}Vol_{catalyst}CC_{replace}/R_{layer}$

Catalyst Replacement Cost = 1 * 21244 * 290 / 2

Catalyst Replacement Cost = $ 3,080,416

2.52 FWF = $i\{1/[(1+i)^Y-1]\}$

2.53 Y = $h_{catalyst}/h_{year}$

Y = 24000 / **5431**

Y = **4**

FWF = 0.07 *(1 /(1 + 0.07)^ 4.00 - 1)

FWF = 0.23

Annual Catalyst Cost = $ 693,796

DAC = **$ 2,794,842**

2.55 CRF = $i(1+i)^n/[(1+i)^n-1]$

CRF = 0.07 *(1 + 0.07)^ 20 /((1 + 0.07)^ 20 - 1)

CRF = 0.0944

Indirect Annual Cost = CFR * TCI

Indirect Annual Cost = 0.0944 * $ 81,042,589

Indirect Annual Cost = **$ 7,649,847**

2.56 Total Annual Cost = Direct Annual Cost + Indirect Annual Cost

Total Annual Cost = $ 2,794,842 + $ 7,649,847

Total Annual Cost = $ 10,444,689 + $ 1,480,000 for LNB+OFA

Total Annual Cost = $ 11,924,689

2.57 NOx Removed = $NOx_{in}\eta_{NOx}Q_Bt_{op}$

NOx Removed = 0.32 * 84% * 5587 * **5431** / 2000

NOx Removed = 12,764 data from CAM

2.58 Cost effectiveness = TAC/NOx removed

Cost effectiveness = $ 934 / ton

Cost effectiveness = $ 6,179,528 / dv

Appendix C

Gerald Gentleman Dry Scrubber

Gerald Gentleman #1 Dry Scrubber

Given/Assumed		
Flow rate (acfm)		
Flue Gas Temperature (degrees F)		
Uncontrolled SO2 emissions (TPY)	24,893	2001 - 2003CAM data
Absorber +	$48,377,000	company report
ductwork	$48,404,000	company report
baghouse modifications	$13,284,000	company report
Retrofit factor	1.0	NPS estimate
SO2 Control efficiency	90%	NPS estimate
Control System Pressure Drop In. wc)		
Operating Hours per Year	8760	NPS estimate
Operating Hours per Shift	8	NPS estimate
Operating Shifts per Year	1095	NPS estimate
Operating Labor Cost ($/hr)	$ 40.60	company report
Maintenance Labor Cost ($/hr)		
Waste generation (lb/hr)		
Waste disposal cost ($/ton)	$ 5.00	company report
Solvent usage (gpm)		
Solvent cost ($/kgal)	$ 1.00	company report
Chemical usage (lb/hr)		
Chemical cost ($/ton)	$ 95.00	company report
Electrical Cost ($/kWh)		
Fan-Motor Efficiency (%)		
Equipment Life (yr)	15	OAQPS Control Cost Manual
Interest Rate (%)	7.00%	OAQPS Control Cost Manual

Gerald Gentleman #1 Dry Scrubber

Capital Cost factors for Gas Absorbers--OAQPS Control Cost Manual, Chap 9

Cost Item		Factor	Cost
Direct Costs			
Purchased equipment costs			
Absorber + auxiliary equipment, EC		A	$110,065,000
Instrumentation		0.10 A	
Sales taxes		0.03 A	$3,301,950
Freight		0.05 A	$5,503,250
Purchased equipment cost, PEC	B=	1.18 A	$118,870,200
Direct installation costs			
Foundations & supports		0.12 B	$14,264,424
Handling & erection		0.40 B	$47,548,080
Electrical		0.01 B	$1,188,702
Piping		0.30 B	$35,661,060
Insulation		0.01 B	$1,188,702
Painting		0.01 B	$1,188,702
Direct installation costs x	1 x	0.85 B	$101,039,670
Site preparation	As required, SP		
Buildings	As required, Bldg.		
Total Direct Costs, DC		1.85 B+SP+Bldg	$219,909,870
Indirect Costs (installation)			
Engineering		0.10 B	$11,887,020
Construction and field expenses		0.10 B	$11,887,020
Contractor fees		0.10 B	$11,887,020
Start-up		0.01 B	$1,188,702
Performance test		0.01 B	$1,188,702
Contingencies		0.03 B	$3,566,106
Total Indirect Costs, IC		0.35 B	$41,604,570
Total Capital Investment = DC + IC		2.20 B+SP+Bldg	$261,514,440

Gerald Gentleman #1 Dry Scrubber

Annual Cost factors for Gas Absorbers--OAQPS Control Cost Manual, Chap 5

Cost Item		Factor	Cost
Direct Annual Costs, DC			
Operating labor			
Operator		0.5 hr/shift	$22,229
Supervisor		15% of operator	$3,334
Operating materials			
Solvent	0 gpm *	$ 1.00 /kgal =	$0
Chemicals	0 lb/hr *	$ 95.00 /ton =	$0
Wastewater Disposal	0 lb/hr *	$ 5.00 /ton =	$0
Maintenance			
Labor		0.5 hr/shift	$0
Material		100.00% of maintenance	$0
Electricity	All electricity equal to:		
fan	0.000181 *	0 acfm* 0 in.wc*	
	8760 hr/yr *	0 unit cost =	
pump			$0
Total DC			$25,563
Indirect Annual Costs, IC			
Overhead		60% of total labor and material costs	$15,338
Administrative charges		2% of Total Capital Investment	$5,230,289
Property tax		1% of Total Capital Investment	$2,615,144
Insurance		1% of Total Capital Investment	$2,615,144
Capital recovery		0.1098 * Total Capital Investment	$28,712,880
Total IC			$39,188,795
Total Annual Cost		DC + IC	$39,214,358

Gerald Gentleman #1 Dry Scrubber

	SO2
Uncontrolled emissions (TPY)	24,893
Control efficiency (%)	90%
Emission reduction (TPY)	22,403
Controlled emissions (TPY)	2,489
Total annualized cost ($/yr)	$39,214,358
Cost/ton removed ($/T)	$1,750

Appendix C

Gerald Gentleman Wet Scrubber

Gerald Gentleman #1 Wet Scrubber

Given/Assumed		
Flow rate (acfm)		
Flue Gas Temperature (degrees F)		
Uncontrolled SO2 emissions (TPY)	24,893	2001 - 2003CAM data
Absorber +	$62,436,000	company report
ductwork	$46,051,000	company report
Retrofit factor	1.0	NPS estimate
SO2 Control efficiency	93.6%	NPS estimate
Control System Pressure Drop In. wc)		
Operating Hours per Year	8760	NPS estimate
Operating Hours per Shift	8	NPS estimate
Operating Shifts per Year	1095	NPS estimate
Operating Labor Cost ($/hr)	$ 40.60	company report
Maintenance Labor Cost ($/hr)		
Waste generation (lb/hr)		
Waste disposal cost ($/ton)	$ 5.00	company report
Solvent usage (gpm)		
Solvent cost ($/kgal)	$ 1.00	company report
Chemical usage (lb/hr)		
Chemical cost ($/ton)	$ 26.00	company report
Electrical Cost ($/kWh)		
Fan-Motor Efficiency (%)		
Equipment Life (yr)	15	OAQPS Control Cost Manual
Interest Rate (%)	7.00%	OAQPS Control Cost Manual

Gerald Gentleman #1 Wet Scrubber

Capital Cost factors for Gas Absorbers--OAQPS Control Cost Manual, Chap 9

Cost Item		Factor	Cost
Direct Costs			
Purchased equipment costs			
Absorber + auxiliary equipment, EC		A	$108,487,000
Instrumentation		0.10 A	
Sales taxes		0.03 A	$3,254,610
Freight		0.05 A	$5,424,350
Purchased equipment cost, PEC	B=	1.18 A	$117,165,960
Direct installation costs			
Foundations & supports		0.12 B	$14,059,915
Handling & erection		0.40 B	$46,866,384
Electrical		0.01 B	$1,171,660
Piping		0.30 B	$35,149,788
Insulation		0.01 B	$1,171,660
Painting		0.01 B	$1,171,660
Direct installation costs x	1 x	0.85 B	$99,591,066
Site preparation	As required, SP		
Buildings	As required, Bldg.		
Total Direct Costs, DC	1.85 B+SP+Bldg		$216,757,026
Indirect Costs (installation)			
Engineering		0.10 B	$11,716,596
Construction and field expenses		0.10 B	$11,716,596
Contractor fees		0.10 B	$11,716,596
Start-up		0.01 B	$1,171,660
Performance test		0.01 B	$1,171,660
Contingencies		0.03 B	$3,514,979
Total Indirect Costs, IC		0.35 B	$41,008,086
Total Capital Investment = DC + IC	2.20 B+SP+Bldg		$257,765,112

Gerald Gentleman #1 Wet Scrubber

Annual Cost factors for Gas Absorbers--OAQPS Control Cost Manual, Chap 5

Cost Item		Factor	Cost
Direct Annual Costs, DC			
Operating labor			
Operator		0.5 hr/shift	$22,229
Supervisor		15% of operator	$3,334
Operating materials			
Solvent	0 gpm *	$ 1.00 /kgal =	$0
Chemicals	0 lb/hr *	$ 26.00 /ton =	$0
Wastewater Disposal	0 lb/hr *	$ 5.00 /ton =	$0
Maintenance			
Labor		0.5 hr/shift	$0
Material		100.00% of maintenance	$0
Electricity	All electricity equal to:		
fan	0.000181 *	0 acfm* 0 in.wc*	
	8760 hr/yr *	0 unit cost =	
pump			$0
Total DC			$25,563
Indirect Annual Costs, IC			
Overhead	60% of total labor and material costs		$15,338
Administrative charges	2% of Total Capital Investment		$5,155,302
Property tax	1% of Total Capital Investment		$2,577,651
Insurance	1% of Total Capital Investment		$2,577,651
Capital recovery		0.1098 * Total Capital Investment	$28,301,224
Total IC			$38,627,166
Total Annual Cost		DC + IC	$38,652,729

Gerald Gentleman #1 Wet Scrubber

	SO2
Uncontrolled emissions (TPY)	24,893
Control efficiency (%)	94%
Emission reduction (TPY)	23,302
Controlled emissions (TPY)	1,591
Total annualized cost ($/yr)	$38,652,729
Cost/ton removed ($/T)	$1,659