



Technical Memorandum #2

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Subject: Estimation of Costs and Impacts of NO_x Control Technologies Applied to the PGE Boardman Plant

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INTRODUCTION

In response to the U.S. EPA final rule on Regional Haze and Best Available Retrofit Technology (BART) determinations, and at the request of the Oregon Department of Environmental Quality (DEQ), Portland General Electric Company (PGE) submitted their proposed BART analysis for the Boardman Plant (PGE Proposal) on November 5, 2007. The PGE proposal was prepared by Black & Veatch (B&V) and CH2M Hill.

In December 2007, Eastern Research Group, Inc. (ERG) was engaged by the DEQ to assist in the evaluation of the PGE Proposal and to conduct an independent feasibility assessment of select options for control of nitrogen oxides (NO_x) from the coal-fired Boardman Plant. ERG's scope of work (SOW), as contained in Contract 055-08, includes the following tasks:

- Task 1: Participate in a kick-off meeting in Portland with PGE, DEQ, and key stakeholder groups
- Task 2: Participate in a site visit to the Boardman Plant
- Task 3: Submit a trip report documenting the results of Tasks 1 and 2
- Task 4: Evaluate the PGE Proposal and submit memo of findings (Memo #1)
- Tasks 5 and 6: Evaluate NO_x control technologies (i.e., low NO_x burners with overfire air and selective noncatalytic reduction, low NO_x burners with overfire air and selective catalytic reduction, and other control options as identified by DEQ), and submit a memo of findings (Memo #2)
- Task 7: Participate in a meeting to discuss findings of Memos #1 and #2 with DEQ, PGE, and other stakeholder groups
- Tasks 8, 9, and 10: Prepare outline of draft report, submit draft report, and meet with DEQ, PGE, and stakeholder groups to discuss draft report
- Task 11: Participate in meeting with DEQ's BART rulemaking Advisory Committee
- Task 12: Submit final report
- Task 13: Provide "as needed" assistance to DEQ within the constraints of the project budget

Tasks 1 and 2 were completed on February 4 and 5, 2008, and the Task 3 trip report was submitted to DEQ on February 15, 2008. The Task 4 preliminary evaluation of the PGE Proposal (Memo #1) was submitted to DEQ on February 25, 2008. This evaluation focused on the NO_x control technologies that were examined by B&V for the Boardman Plant; however, the evaluation was considered preliminary because answers to most of the questions asked of PGE and B&V at the February meetings had not as yet been provided. The memo cited selective catalytic reduction (SCR) installed costs as the major issue to be resolved and most other comments were fairly minor (i.e., not likely to substantially change the BART determination).

This Task 6 memorandum (Memo #2) documents the results of ERG's complete evaluation of the PGE Proposal, as well as our own feasibility assessment of select technologies for controlling NO_x at the Boardman Plant (Task 5). Memo #2 is organized as follows:

- **Summary of Methods and Findings:** This section contains a brief overview of the method used by ERG to evaluate the PGE Proposal and assess the various characteristics of each NO_x control technology (i.e., performance, energy and non-air quality impacts, and cost).
- **Section 1.0, Control Technologies Selected for Analysis:** This section lists and describes the NO_x control technologies reviewed by ERG and contained in the PGE Proposal for the Boardman Plant. Also, the impact of the NO_x controls on the DEQ's requirements pertaining to mercury for Boardman is discussed.
- **Section 2.0, ERG's Cost Estimation Methodology:** This section describes the inputs and outputs of the cost estimates developed by ERG using the CUECost model. Conclusions are presented regarding the appropriateness of this method for use on Boardman's NO_x control retrofit options.
- **Section 3.0, Comparison of PGE Proposed Costs and ERG Costs Estimates for NO_x Control:** This section compares the results contained in the PGE Proposal for the range of NO_x controls, to ERG's estimates. This section addresses the significant issue of how best to estimate SCR installed costs for the Boardman Plant in view of widely varying costs that results from various approaches.
- **Section 4.0, Conclusions:** This section provides ERG's findings with regard to the PGE Proposal for the Boardman Plant's NO_x and mercury control technologies.

SUMMARY OF METHODS AND FINDINGS

Based on the experience of ERG's NO_x control expert and relevant literature, ERG evaluated the performance and energy and non-air quality impacts of the NO_x control technologies identified by DEQ for this analysis, and evaluated in the PGE Proposal for the Boardman Plant, including (combinations of): new low NO_x burners (NLNB), advanced overfire air (AOFA), selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR). Our findings are as follows:

- With regard to the performance of NLNB with AOFA, ERG acknowledges that the unusual furnace internals at the Boardman Plant (i.e., wing or division walls extending well below the boiler nose) will limit the effectiveness of these controls in reducing NO_x, and finds that the B&V estimate of 0.28 lb/MMBtu does not seem unreasonable.

- With regard to the performance of existing low NO_x burners (LNB) with overfire air (OFA) and SCR, reductions of 70 to more than 90 percent have been documented from recent installations; however, these are based on units that operate mainly during the ozone season and that have substantial opportunity for off-season maintenance and catalyst cleaning. The impact of existing LNB with OFA and SCR at the Boardman Plant under year-round operation would need to be considered in selecting a permit level.
- With regard to SNCR performance, although SNCR installations on boilers have been demonstrated to achieve between 25 and 50 percent reduction in NO_x, very large boilers (>300 MW) generally are limited to lower SNCR removal efficiencies. The Boardman Plant is large and has division walls, noted above, that limit upper furnace mixing. In Memo #1, ERG expressed concern that SNCR might not achieve the 20 to 25 percent that B&V was predicting for Boardman. B&V has since requested a more detailed assessment of the unit by Fuel Tech, the country's leading SNCR vendor and has reduced the estimated performance to 18 percent to be conservative.
- With regard to energy and non-air quality impacts, ERG finds that there are no significant impacts from existing/new LNB, AOFA, or SNCR. In general, ERG agrees with the PGE Proposal that SCR has three (potential) adverse impacts as compared to SNCR: an SCR unit requires at least 36 times as much electricity to operate as SNCR; disposal of spent catalysts create hazardous waste (although ERG believes evolving catalyst management practices may minimize this impact); and anhydrous ammonia releases create an additional accidental release hazard. In some cases, utilities have chosen to avoid this hazard by generating ammonia "on demand" from urea, although this involves added capital and operating expense.

ERG's method for evaluating cost of the NO_x control technologies included use of the CUECost estimation program. The CUECost program is widely accepted and used by the utility industry and government agencies for estimating costs for controls applied to coal-fired power plants. While ERG believes that CUECost is appropriate for estimating cost for relatively small construction projects (e.g. NLNB, AOFA and SNCR retrofits for coal-fired power plants), we do not believe that CUECost accurately reflects installed costs for major construction projects, such as SCR and flue gas desulfurization (FGD), for reasons that evolved through this study. These findings are described below.

From the outset, the majority of ERG's attention and effort focused on the probable installed cost of SCR at the Boardman Plant. In our preliminary evaluation (Memo #1), ERG believed that the SCR installed cost estimate provided on page D-9 of the PGE Proposal overstated the likely cost (2007 cost-basis), possibly by as much as a factor of two. We focused on the SCR installed cost because:

- SCR is widely and successfully applied on Powder River Basin (PRB) coal units throughout the country;
- SCR is effective in reducing NO_x to very low levels; and
- SCR represents a substantial increase in installed cost as compared to SNCR (which is the BART technology proposed by PGE).

For quite some time, the power plant NO_x control community has used \$100/kW as a rule-of-thumb installed cost for SCR installed on coal-fired power plants. This was based on costs

reported for some early installations in the 1990s and early cost studies by the U.S. Environmental Protection Agency (U.S. EPA) and others. As we started this analysis of the PGE Proposal, ERG was aware of three literature papers that addressed SCR installed costs (Hoskins, 2003; Cichanowicz, 2004; Marano and Sharp, 2006) with cost-basis years of 2002, 2003 and 2005, respectively. These papers provided evidence that the \$100/kW rule-of-thumb did not correspond to the costs being experienced by utilities installing SCR in the 2002–2005 timeframe. In an initial conference call with DEQ personnel, ERG expressed an opinion that SCR installed costs for Boardman may be on the order of \$150/kW or about one half the \$309/kW that was contained in the PGE Proposal.

Section 3.0 of this memo contains a discussion of three avenues of analysis that ERG has pursued to evaluate the probable installed cost of SCR at Boardman. These are:

- Bottom-Up installed cost using the CUECost Model with the Chemical Engineering Construction Cost Index for 2007 applied.
- Top-Down literature values obtained from the SCR installed costs as reported in various Internet and subscription sources.
- A current B&V “real” project cost that ERG was permitted to examine (under terms of a confidentiality agreement) in the B&V offices in Overland Park, Kansas.

ERG supplemented these cost sources with literature papers and relevant study findings concerning the general escalation in heavy construction cost resulting from the world-wide commodities bubble and construction labor shortages.

The CUECost program generates an installed cost of \$70/kW to \$130/kW; however, we feel this does not represent the probable cost of SCR applied to the Boardman Plant.

The top-down literature values analysis is based on a large number of data points including 33 SCR project installed costs provided by PGE and B&V in an April 6, 2008 submission to DEQ. Although there are many data points in this dataset, the quality of the individual points is difficult, and in some cases impossible, to assess. Nonetheless, all of these sources do point to a rapid escalation in SCR installed costs since 2004. ERG analyzed the 2007 cost-basis data by eliminating the three highest and three lowest cost projects and one project that was known to be very dissimilar to the Boardman Plant characteristics. The remaining nine projects range from \$207/kW to \$267/kW, with an average of \$227/kW. ERG believes that this is a reasonable representation of 2007 costs of large SCR installations under normal retrofit conditions.

ERG examined the actual cost data (i.e., both the bid cost developed for the project proposal and the actuals from the B&V project accounting system) for a recent SCR project performed by B&V. The total installed cost for this project was \$221/kW on a 2007 cost-basis. This project cost falls near the middle of the costs resulting from the analysis of the 2007 top-down literature values described above and thus provides confirmation that the range of \$207/kW to \$267/kW is reasonable.

Certain retrofit conditions at the Boardman plant tend to increase the installed cost, and others tend to reduce costs. The fact that some boiler modifications will be needed (due to the high

flue gas temperature at the economizer outlet) that are not typical of SCR retrofit projects, tends to offset some of the cost-lowering factors present at the Boardman Plant. With all of these factors taken into consideration, ERG concludes that the Boardman Plant SCR installed cost would be at the high end of the \$207/kW to \$267/kW range cited above (a detailed analysis of this finding is in Section 3.4 of this memo). However, since no detailed design of the Boardman Plant SCR has been carried out, there is a fairly broad uncertainty band associated with all of these cost estimates.

Table 1 of this memo provides a side-by-side comparison of the costs for all NO_x control technologies evaluated in the PGE Proposal, and by ERG using the research and methods described above. Differences in costs range from less than 1 percent (for NLNB) to 100 percent for existing LNB with OFA and SNCR. Differences between PGE and ERG cost estimates for SCR range from 24 percent (SCR with existing LNB and OFA) to 27% (SCR with NLNB and AOFA).

1.0 CONTROL TECHNOLOGIES SELECTED FOR ANALYSIS

DEQ directed ERG to review several specific NO_x controls for potential use at the Boardman Plant. These controls, listed below, were also contained in the PGE Proposal and initially reviewed by ERG in Memo #1 (submitted to the Oregon DEQ on February 25, 2008):

- New low NO_x burners (NLNB)
- NLNB with advanced overfire air (AOFA)
- Existing LNB with OFA and selective catalytic reduction (SCR)
- Existing LNB with OFA and selective noncatalytic reduction (SNCR)
- NLNB with AOFA and SCR
- NLNB with AOFA and SNCR

The remainder of this section discusses the performance (i.e., percent reductions and emission rates in pounds per million BTU [lbs/MMBtu]) and energy and non-air quality environmental impacts for each of the NO_x controls. Also, the potential impacts of each NO_x control on DEQ's existing mercury control requirement for the Boardman Plant are discussed.

1.1 Performance of NO_x Controls

New Low NO_x Burners

Improvements to LNB design since development of the first generation of LNBs have achieved an additional 20 to 40% reduction in NO_x in comparison to first generation LNBs. The PGE Proposal indicates that the Boardman Plant was issued a construction permit in 1977. As part of the permit, PGE utilized first generation low NO_x burners (LNB) in combination with overfire air (OFA) to reduce NO_x emissions. This combination of controls is discussed below.

New Low NO_x Burners with Advanced Overfire Air

Since the early to mid-1990s, boosted overfire air systems (referred to as advanced overfire air or AOFA) began to be operated. This OFA system can be installed over the existing wind

boxes for retrofit installations. Advanced OFA systems add air ports to several walls of the furnace, in addition to just the burner walls. Due to fan systems and extra air ports, more flow can be diverted than in the original OFA system. The extensive placement of ports in the AOFA system also allows air to be diverted to a greater area of the furnace interior. The NO_x removal efficiency of the AOFA system ranges from 15 to 25 percent compared to the baseline case. New LNBS in combination with AOFA systems have been demonstrated to achieve NO_x emission levels as low as 0.15 lbs/MMBtu for some wall-fired boilers firing PRB coal. However, for reasons discussed below, ERG does not believe that 0.15 lbs/MMBtu is achievable at the Boardman Plant.

There are a number of instances of NLNB/AOFA retrofits on units that burn PRB coal where the resulting NO_x emission level is reported to be 0.15 lbs/MMBtu. An examination of the individual units involved shows that all but one of the units are tangential-fired with very low pre-retrofit NO_x emission levels. The single wall-fired unit is discussed in a paper prepared by the vendor, Riley Power (Penterson, 2003). The specific unit is not identified in the paper, nor is the owning utility identified. The paper does discuss some characteristics of the unit which are not typical of most wall-fired boilers. Specifically, when the unit was originally started up, it was determined that it could not be fired at its intended full rating. Sixteen of the original burners were removed resulting in a substantial derating and a very low initial NO_x of 0.30 lbs/MMBtu. The initial NO_x at Boardman (0.43 lbs/MMBtu) is more than 40 percent higher than the unit described in the Penterson paper and the achievement of 0.15 lbs/MMBtu at Boardman Plant by retrofitting NLNB and AOFA does not appear feasible.

Also, the furnace internals at the Boardman Plant appear to be rather unusual in that the wing (or division) walls extend well below the boiler nose. More typically, in-furnace pendant pressure parts would extend down to the nose. The Boardman Plant upper furnace has wing-walls that suspend from the furnace roof to about midway down to the furnace floor. They appear also to extend from the front wall to about midway to the back wall and will present problems both in getting good mixing of the AOFA and possible rapid tube corrosion due to the strongly reducing flue gas conditions, if deep-staging is attempted in the Boardman furnace.

The non-typical situation at Boardman Plant will, in the opinion of ERG, limit the effectiveness of NLNB and AOFA in reducing NO_x. Determining exactly how much reduction could be achieved would require detailed computational fluid dynamics (CFD) modeling; however, the B&V prediction of 0.28 lb/MMBtu does not seem unreasonable.

Low NO_x Burners with Overfire Air and Selective Catalytic Reduction

Recent installations on utility boilers have shown that SCR can achieve 70 to more than 90 percent efficiency, and NO_x emission levels as low as 0.05 lbs/MMBtu. Similarly, SCR in combination with LNB with OFA or NLNB with AOFA have been demonstrated to achieve NO_x emissions as low as 0.05 lbs/MMBtu. Most of this experience is with ozone-season units that have a substantial opportunity for off-season maintenance and catalyst cleaning; therefore, the impact of year-round operation would have to be considered in selecting a permit level for the Boardman Plant.

Low NO_x Burners with Overfire Air and Selective Noncatalytic Reduction

SNCR installations in combination with LNB with OFA or NLNB with AOFA on utility boilers have been demonstrated to achieve between 25 and 50 percent reduction. The reduction percentage that can be achieved is extremely unit-specific and fairly large units generally achieve reductions at the low end of the range. ERG has expressed concern that high upper furnace temperatures at the Boardman Plant, and the effect of the wing walls on upper furnace mixing mentioned earlier, might severely limit reductions achievable at the plant. During a meeting at B&V offices in Kansas on April 24, 2008, B&V indicated that they have had Fuel Tech (a leading SNCR vendor) conduct further examination of the Boardman unit. Fuel Tech confirmed that there was an appropriate injection location (in the upper backpass, rather than the usual upper furnace location), and that 25 percent reduction is feasible. B&V said that they were assuming 18 percent in their estimates to be conservative.

1.2 Energy and Non-Air Quality Environmental Impacts

Existing/New Low NO_x Burners, Existing/Advanced Overfire Air, Selective Noncatalytic Reduction

There are no significant energy or non-air quality environmental impacts from use of existing or NLNB, existing or AOFA, or SNCR.

Selective Catalytic Reduction

The PGE Proposal cites three energy and non-air quality environmental impacts for which SCR is disadvantaged when compared to SNCR:

- B&V calculates that the SCR unit will require 36 times as much electric power as SNCR, due to the additional fan power needed to overcome the catalyst bed pressure drop. ERG believes that this figure may be low. CUECost generates a differential of about 100 times for the same SCR-to-SNCR comparison.
- The PGE Proposal cites the disposal of spent catalyst as a hazardous waste as being a non-air quality environmental impact. This may be of little significance, based on evolving catalyst management practices. Catalyst regeneration processes potentially allow for reuse of the catalyst modules for several cycles, making the disposal cost and environmental impact much less than earlier industry estimates.
- The PGE Proposal cites the additional accidental release hazard associated with anhydrous ammonia (for SCR) versus urea solution for SNCR. Although the remote location of Boardman makes this less of an issue when compared to urban and suburban power plants, nevertheless, there is added hazard for plant personnel and the few people that may live or be present in the path of an ammonia plume from the plant. This hazard can be remedied for a price. Today, there are commercially available systems that convert urea to ammonia “on demand”, with no significant ammonia inventory present at the facility at any time. As noted, this is an additional capital and operating cost for the SCR installation. It should also be noted that ammonia is a fairly common industrial chemical and refrigerant and there are established safeguards and procedures for its handling and storage.

In general, ERG agrees with the PGE Proposal assessment of these impacts, at least qualitatively.

1.3 Mercury Control Technologies

Additionally, the effect of the NO_x controls on reducing mercury emissions was also evaluated. PGE proposes to retrofit a fabric filter downstream of the existing electrostatic precipitator (ESP) to enhance the control of particulate matter at the Boardman Plant. The PGE Proposal states that this technology selection was driven, in part, by the future need to control mercury emissions with dry sorbent injection. This approach is consistent with the approach taken throughout the industry for power plants burning PRB coal. Because mercury contained in PRB coal flue gas is not readily oxidized by SCR catalysts for subsequent collection in a flue gas desulfurization (FGD) system, virtually all near-term mercury control for PRB units will be through the use of activated carbon injection (or injection of enhanced activated carbon). In a very recent study by The Shaw Group (Wedig et al., 2008) published in the May 2008 issue of Power Magazine, the authors identified a total of 51 PRB plants (8 new and 43 retrofit) that have committed to mercury control, all proposing activated carbon injection.

None of the other NO_x controls considered (i.e., NLNB, AOFA, SNCR) would have any impact on the Boardman baseline mercury emissions. Also, for reasons stated in the previous paragraph, capture of mercury in an FGD system (wet, dry, or semi-dry, would be very small and Boardman, like other PRB coal-fired units, will need to rely on some form of carbon injection for mercury control.

2.0 ERG'S COST ESTIMATION METHODOLOGY

The U.S. EPA's BART guidance (www.epa.gov/air/visibility/pdfs/guidelines_2005_6_24.pdf) recommends: "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, Fifth Edition, February 1996, EPA 453/B-96-001)." Consequently, ERG reviewed the procedures in the available cost estimation methodologies, the OAQPS Cost Manual, and also the CUECost estimation program to determine the most appropriate methodology for providing capital and annual costs. Initially, ERG decided that the CUECost estimation program was more appropriate because it provided costs separated into elements which could be compared to the specific cost elements used by B&V in developing the PGE Proposal. Also, the CUECost program is widely accepted and used by the utility industry and government agencies to provide cost estimates, and it is tailored to air pollution controls applied to coal-fired power plants.

The remainder of this section describes the CUECost input data used by ERG, and provides our conclusions related to CUECost's ability to predict "real world" costs for projects requiring major heavy construction (e.g., SCR) as compared to smaller projects (e.g., NLNB, AOFA, and SNCR) that do not require major structural work or large process equipment. Based on our conclusions, we deviate from a CUECost approach when preparing an independent estimate for SCR installed cost; this is explained in detail below in Section 3.4 of this memo.

2.1 Cost Algorithm Inputs

The CUECost program provides cost estimates for new LNB, SCR, and SNCR. The cost factors for AOFA provided in an earlier analysis conducted by ERG for the Western Regional Air Partnership (WRAP) were used to calculate the capital costs. The WRAP report indicates that in 2005, the installed capital cost for AOFA was \$8.80/kW. The total capital investment for the combinations of NO_x controls using AOFA were calculated by adding the AOFA capital costs.

Attachment A lists the inputs necessary to run the CUECost program for NO_x control technologies, and the rationale for use of the different inputs. The attachment also provides the inputs used in the analysis and the source of the input data. After reviewing the PGE Proposal CUECost inputs, ERG concludes that most of the inputs that were used for PGE's CUECost runs were appropriate for the analysis. Consequently, where possible, we used inputs provided by PGE for our assessment. Attachment B contains detailed cost outputs from CUECost for NLNB, AOFA, SNCR, and SCR. Attachment C shows a detailed comparison of the PGE and ERG CUECost estimates for total capital investment of SCR, which is a main area of disagreement (see Section 3.4 for more details on this comparison).

The CUECost program was last updated in 2002. For the outputs to be relevant, ERG escalated the costs to 2007 using Chemical Engineering magazine cost factors.

2.2 Conclusions Regarding the Use of CUECost for the Boardman Analysis

As discussed later in detail in Section 3.4 of this memo, ERG's investigation of SCR installed costs for the 2007 cost-basis year has led us to the conclusion that CUECost does not provide "real world" costs for SCR in the current environment for major construction projects. Similarly, based on a study prepared for the National Lime Association (Sargent and Lundy, 2007) and a study by Cichanowicz for the Utility Air Regulatory Group (Cichanowicz, 2007), there is good evidence that FGD (i.e., another technology requiring heavy construction) installed costs have escalated at an unprecedented rate since about 2004. CUECost, even when inflation-adjusted by applying the current Chemical Engineering Construction Cost Index, appears to produce installed costs that are well below those that appear in the recent literature. However, for relatively "smaller" projects, such as LNB, AOFA, and SNCR retrofits, we believe that estimates developed using CUECost are reasonable.

ERG was not able to determine why CUECost seems unable to generate costs corresponding to current experience; however, Cichanowicz, et al. (Cichanowicz et al., 2006), speculated that early SCR installations may have been misleading due to under-design (that resulted in failure to meet performance objectives) and selection of favorable retrofit units for early installations. Also, some features now considered more or less standard (e.g., large pitch catalyst, popcorn ash screens, static mixers, and provision of a great deal of sootblower capability) were not part of early system designs. Finally, vendors were clearly positioning for the surge of installations in 2002, 2003 and 2004, and substantial cost overruns may have been absorbed by the vendors and constructors, and would not necessarily be reported by the utilities or appear in the literature. In the recent worldwide high-demand environment for industrial construction

services and equipment, the opposite effect may be taking place, where engineering firms, constructors and equipment manufactures are bidding with high profit margins and large contingency factors, driving up installed costs.

Although ERG is convinced that CUECost fails to provide “real world” installed costs for major construction projects such as SCR retrofits, we are not able to necessarily extend this to projects that do not require extensive “construction” (e.g., extensive foundations and structural works, ductwork modifications, etc.) and projects where retrofit issues do not heavily influence installed costs. For smaller projects such as NLNB, AOFA and SNCR, largely because we have no evidence to the contrary, we have used CUECost results escalated to 2007 by applying the 2007 Chemical Engineering Construction Cost Index.

3.0 COMPARISON OF PGE PROPOSED COSTS AND ERG COST ESTIMATES FOR NO_x CONTROL

This section compares the PGE proposed costs with the ERG costs for the NO_x control technologies selected for this analysis. Table 1 summarizes the total capital cost in units of \$/kW from the PGE Proposal and as estimated by ERG for each NO_x control technology. A discussion of each of the comparisons is provided below for NLNB (Section 3.1), NLNB with AOFA (Section 3.2), SNCR (Section 3.3), and SCR (Section 3.4).

3.1 NLNB Comparison

The capital cost estimates for NLNB from ERG’s CUECost run differs by less than 1% of the estimate provided by PGE. This difference was not considered significant and, therefore, not analyzed further.

3.2 NLNB with AOFA Comparison

The difference in total capital cost of NLNB with AOFA between the PGE Proposal and ERG’s estimates is due to PGE’s use of handling and erection cost factors that are higher than those in CUECost to estimate direct installation costs. The handling and erection factor (50 percent of the purchased equipment cost) is approximately 20 to 30 percent higher than cost factors used in CUECost and in EPA’s OAQPS Cost Manual. These additional costs then propagate further when calculating Indirect Costs and Total Capital Investment. The PGE Proposal included costs for the following ancillary equipment: neural network system, NO_x monitoring equipment, water cannon, and modulating orifice for burners. These additional cost items add approximately \$8/kW to the total installed cost.

ERG agrees that certain upgrades such as neural networks and burner air controls are part of general system upgrades that allow NLNB with AOFA to achieve and maintain optimum performance. Also, PGE reported that slagging has been a recurring problem when the current OFA system is operated continuously. Water cannons have been used extensively for PRB units throughout the country. ERG’s cost is based on a combination of the CUECost result (\$28/kW) and the cost of the ancillary equipment noted above (\$8/kW) for a total of \$36/kW. The PGE Proposal cost is \$53/kW, or about 47% higher.

Table 1. Comparison of PGE Proposed Costs and ERG Costs for NO_x Control at the Boardman Plant

Control Technology	Cost Estimate in \$/kW		% Difference	Notes
	PGE	ERG		
NLNB	18	18	< 1%	CUECost and PGE estimates are essentially the same.
NLNB with AOFA	53	36	47%	PGE cost is much higher than CUECost results. PGE added equipment items not included in CUECost. ERG agrees that these items are warranted and that the probable cost is about \$8/kW. This cost was added to the CUECost result to arrive at the ERG estimate.
Existing LNB with OFA + SNCR	28	14	100%	ERG cost is based on CUECost and confirmed by leading SNCR vendor public statement. ERG does not know the basis of PGE's estimate and cannot duplicate it.
NLNB with AOFA + SNCR	81	50	62%	Cost is based on adding the NLNB with AOFA cost to the SNCR cost, above.
Existing LNB with OFA + SCR	309	250	24%	ERG cost is based on the high end of the range of costs (\$207/kW to \$267/kW) that ERG found to be reasonable based in the analysis described in Section 3.4 of this memo.
NLNB with AOFA + SCR	362	286	27%	Costs are based on summing the cost of "stand-alone" SCR with the cost of NLNB/AOFA. Probably costs should be slightly lower because of reduced inlet NO _x .

ERG does not have information that would support the higher erection factor used by PGE as compared to the CUECost default values. However, we do note again that there has been rapid escalation in construction costs in recent years for SCR that does not seem to be captured by CUECost using the Chemical Engineering Cost index.

3.3 SNCR Comparison

For the option of using the existing LNB with OFA along with a new SNCR, PGE's Proposal indicated that CUECost was used to calculate costs of the SNCR system. However, PGE's CUECost outputs could not be duplicated using the inputs provided in the PGE Proposal. Insufficient information was provided to fully assess the reason for the differences. The costs estimated by PGE for reagent storage, handling, injection and controls were \$5,100,000 compared to the CUECost output of \$1,730,000. Air heater modifications calculated by PGE were \$2,835,000 compared to the CUECost output of \$1,400,000. These additional costs then propagate further when calculating indirect costs and total capital investment.

Fuel Tech's Dr. Bill Sun, a longtime expert on SNCR, recently placed SNCR installed costs at \$5 to \$20/kW (Sun, 2007). The CUECost estimate of \$14/kW falls comfortably within the range indicated by Fuel Tech. This cost would apply to both the existing LNB with OFA and NLNB with AOFA, as SNCR capital costs are relatively insensitive to initial NO_x emissions levels. The PGE Proposal contains an installed cost of \$28/kW for SNCR (which we cannot reproduce); this is at least 50 percent higher than the CUECost estimate for SNCR.

3.4 SCR Comparison

ERG reviewed the SCR installed cost contained in the PGE Proposal. The review has involved a number of information-gathering steps and discussions with DEQ, PGE and B&V. The following activities have taken place since the start of the project in January 2008:

- January 18 - After a brief review of the BART Proposal, ERG and DEQ conducted a conference call to plan initial steps. During this call ERG gave its initial reaction to the PGE Proposal and cited the SCR installed costs as, in our opinion, well above costs appearing in the literature.
- February 4 - ERG attended the Stakeholder Meeting at Stoel Rives LLP. B&V presented the main points of the BART Proposal and ERG provided 14 questions in writing. These questions were combined with dozens of other questions raised by the stakeholders attending the meeting.
- February 5 - ERG attended a tour of the Boardman Plant.
- February 15 - ERG submitted a trip report covering the February 4 meeting and the February 5 plant tour.
- February 15 - ERG received and reviewed the B&V response to ERG question #2, which asked for the plant, economic, and NO_x inputs used for the CUECost model runs that were used in the PGE Proposal. In some ways, the response confused these issues rather than clarifying them, since the data and discussion in the response did not correspond to the discussion in the PGE Proposal (i.e., different inlet NO_x, different percent removal).
- February 25 - ERG submitted Memo #1 to DEQ, discussing the ERG review of the PGE Proposal. SCR installed cost was identified as the primary concern. Most other comments were relatively minor.
- March 23 - ERG received and reviewed the PGE/B&V responses to 101 questions that were recorded at the February 4 and 5 meetings.
- April 6 - ERG received and reviewed a B&V discussion of current and historical SCR installed costs. This submission included installed costs for 33 SCR projects (both single unit and multiple unit projects) with the cost-basis year, unit size, and installation year. These were obtained from the open literature and subscription sources. Both actual completed projects and future (estimated cost) installations are included.
- April 24 - ERG attended a meeting and discussion at B&V offices in Kansas. At this meeting, B&V presented a detailed cost estimate for a current SCR project that is similar enough in size as to be relevant to the potential Boardman installed cost.

The primary issue is: *How to estimate SCR installed cost for the Boardman Plant in view of widely varying costs that result from various sources and approaches?*

We examined three fundamentally different costing approaches to address this issue:

- Bottom-up installed cost using the CUECost Model
- Top-down literature values
- B&V “real” project cost

In addition, we examined the general escalation of construction costs due to the commodities bubble and labor shortages. These approaches and the general escalation of construction costs as related to SCR are discussed in detail below.

Bottom-Up Installed Cost Using the CUECost Model

CUECost is a widely-used, U.S. EPA-developed cost model for air pollution controls applied to coal-fired power plants. When the model is run with Boardman-specific technical inputs, the default economic inputs, a “difficult” retrofit factor and escalated to 2007 dollars, the result for Boardman is about \$100/kW. Since the developers of CUECost specifically caution that the level of detail involved results in a plus-or-minus 30 percent estimate, the CUECost estimate for the Boardman Plant would actually be \$70/kW to \$130/kW. However, a number of recent studies of actual installed costs for completed installations and estimates for near-term future installations call into question the direct use of CUECost in today’s construction environment. For reasons noted below, it is ERG’s opinion that the CUECost model does not generate “real world” SCR installed cost estimates.

Top-Down Literature Values

There are three fairly recent literature papers that address SCR installed costs (Hoskins, 2003; Cichanowicz, 2004; Marano and Sharp, 2006). In a paper prepared for the Utility Air Regulatory Group, Cichanowicz compiled SCR installed costs from the same three papers (Cichanowicz, 2007). Also, Internet searches produced a number of other anecdotal examples of recent plant-specific costs. Although there are many data points in this dataset, the quality of the individual points is difficult, and in some cases impossible, to assess. Nonetheless, all of these sources do point to a rapid escalation in SCR installed costs since 2004.

In their April 6 submission, B&V compiled installed costs for 33 SCR projects, including both single unit and multiple unit installations. The average SCR installed cost for the 2007 projects was \$242/kW, and B&V concluded that these data are consistent with their Boardman Plant estimate of \$309/kW when the proposed Boardman boiler modifications, at \$65/kW, are added. (Note: the Boardman Proposal [at page D-9] includes the cost of NLNB and AOFA along with the SCR cost, resulting in a total of \$362/kW for the combined technologies.)

ERG examined the 33 individual data points (installed cost, cost-basis year) and determined that several of the critical (2007 cost-basis) data points are skewed somewhat to the high side. For example, 6 of the data points for 2006 represent projects at Progress Energy’s Ancolote and Crystal River plants. The data for cost-basis year 2007 contains these same projects, escalated by 70 percent based on a blanket statement by a Progress Energy official that the cost of new air pollution controls have “jumped 70% from their 2006 submission” (to the Florida Public Service Commission). An examination of the source document shows that the 2006 submission actually contained estimates with a 2005 cost-basis. Also, the implied 70 percent

escalation from 2006 to 2007 is in conflict with a statement by Kentucky Utilities (before the Kentucky Public Services Commission) that the installed cost estimate of SCR for Ghent Unit 2 had increased by 21 percent from 2006 to 2007. The 70 percent escalation figure is also inconsistent with a number of other papers (see below) that address the general cost escalation for various types of utility construction in the current environment.

Two of the critical 2007 cost-basis data points were contained in the BART proposals for Gerald Gentleman Units 1 and 2 (\$334/kW) and Nebraska City Unit 1 (\$376/kW). In both cases, the estimate was provided by architectural and engineering firm HDR. The estimates were described as based on 2002 vendor quotes for major equipment, adjusted for capacity (the quotes were not for the specific plants involved), escalated to 2007 (by applying a 68 percent escalation factor), doubled to account for construction costs, and multiplied by a 25 percent contingency factor. ERG does not accept that these very crudely developed costs represent useful data in evaluating cost of the Boardman Plant retrofit.

Finally, an examination of the year-to-year escalation implied by the 33 data points provided by B&V calls into question the quantitative use of the data (though it is certainly useful in a qualitative sense.). For the B&V dataset, the year-to-year changes in historical average installed costs are:

- 2002 to 2003 = +80 percent
- 2003 to 2004 = +76 percent
- 2004 to 2005 = +25 percent
- 2005 to 2006 = -37 percent
- 2006 to 2007 = +62 percent

Obviously, these year-to-year variations, including a drop in cost of 37 percent from 2005 to 2006, are an indication that these data are not useful in any given year in a quantitative sense. They do, however, support the contention that the last several years have seen construction cost escalation that is significantly above the general consumer inflation rate in recent years.

To more closely examine these data in a quantitative sense, ERG eliminated the three highest (including the afore mentioned HDR estimates) and three lowest estimates contained in the 16 projects which make up the 2007 basis-year data. We also eliminated the WE Energies' Oak Creek Units 5 and 6 project since these are small, tail-end systems. The remaining nine projects are fairly tightly grouped, providing some comfort that they represent "typical" installations, rather than outliers. **These projects range from \$207/kW to \$267/kW, with an average of \$227/kW.** The fact that the average is very close to the B&V "real" project cost discussed below tends to confirm that this range (\$207/kW to \$267/kW) is a reasonable representation of 2007 costs of large SCR systems and normal retrofit conditions.

B&V "Real" Project Cost

At an April 24, 2008, meeting at the B&V offices, an ERG engineer was presented with detailed estimates for two very recent B&V SCR installations. After examining the "specifics" of one of the projects, ERG concluded that it was too different (i.e., much smaller, hot-side ESP, low-dust SCR) to provide a relevant data point for the Boardman Plant retrofit. The

second plant was sufficiently close in “specifics” to the Boardman Plant to be relevant. Clearly, the cost details were based on B&V actual costs, and were not prepared specifically for ERG’s visit. They correspond roughly to 2007 dollars since the project start was mid-2006 and it is now just wrapping up. B&V provided the estimate for this same unit, reformatted to correspond to the line items on page D-9 of the PGE Proposal.

The B&V “real” project cost of \$221/kW that was provided in the D-9 format exhibits some line-by-line differences when compared to the Boardman Plant SCR estimate prepared by B&V for PGE. These differences include higher total purchased equipment costs, lower total direct installation costs, and a much higher cost for site preparation and buildings at the Boardman Plant. The most significant difference the Boardman Plant estimate and the B&V “real” project cost is the \$65/kW added to account for boiler modifications to reduce the SCR flue gas inlet temperature. Also, the Boardman BART Proposal SCR estimate includes an additional \$53/kW for NLNB with AOFA. ERG believes that the benefit of the NLNB with AOFA system (i.e., lower SCR inlet NO_x) is not properly reflected in the PGE Proposal’s SCR cost estimate.

In spite of some of the differences cited above, ERG believes the “real” project cost data that were reviewed at the B&V offices on April 24, 2008, support the PGE/B&V position that CUECost, when run with default values and an escalation factor, does not generate “real world” SCR installed costs for a 2007 cost-basis year.

General Escalation of Construction Costs due to the Commodities Bubble and Labor Shortages

In addition to the three costing approaches described above, ERG considered a fourth factor in analyzing the Boardman Plant SCR estimate contained in the PGE Proposal. In their April 6, 2008 submission of historical SCR installed cost data, B&V included two recent articles that deal with rapidly escalating construction in the utility industry (Chupka and Basheda, 2007; Schimmoller, 2007). Although these articles do not address SCR specifically, they do give a clear sense that construction costs are escalating at a rate well above historical norms. In a report prepared for the National Lime Association, Sargent and Lundy pegged the recent escalation of FGD installed costs at 25 percent per year (Sargent and Lundy, 2007) (Note: FGD retrofits involve the same type of major structural work, large process equipment and retrofit issues that are present with SCR installations.). As noted earlier, Kentucky Utilities estimated an increase of 21 percent for the Ghent Unit 2 SCR cost from a 2006 to a 2007 cost basis. All of these are indications that the effect of world demand for construction materials, equipment, and labor are exerting a strong upward pressure that has impacted SCR installed costs in the U.S.

Summary of SCR Cost Analysis

It is ERG’s opinion, based on a distillation of the three cost approaches discussed above and the general rapid cost escalation environment, that the 2007 installed costs for SCR range from \$207/kW to \$267/kW, barring any extremely favorable or unfavorable site-specific conditions.

In the Boardman case, there are factors that would tend to push costs toward the high end of the range and other factors that would tend to reduce costs. Some of the factors that tend toward higher cost include:

- Use of PRB coal (as compared to bituminous coal);
- The Boardman Plant's remote location and its impact on labor availability and cost;
- The higher-than-normal structural bridge needed to span the ESP; and
- The boiler modifications needed to adjust inlet flue gas temperatures.

Some of the cost-reducing factors include:

- A unit size that is large enough to provide economy of scale, but small enough to fit the catalyst box between the unit and the stack;
- A single-unit plant with much clear space around the rear of the plant; and
- (Importantly) the low inlet NO_x and low removal efficiency specified in the PGE Proposal.

Although some of the site-related factors are favorable (e.g., clear space, single unit plant), the major complicating factor is the boiler modifications for flue gas temperature adjustment, which B&V places at \$65/kW. ERG believes, based on conversations with B&V personnel, that B&V has not analyzed this cost in detail (nor has ERG). ERG notes that, in general, all SCR retrofits require ductwork modifications at the rear of the boiler and in many cases, an economizer bypass is included, thus some of the costs associated with fitting the SCR into the boiler/airheater train are already contained in SCR estimates. Anecdotal information on pressure part replacement projects (from the Internet) gives us the impression that the B&V estimate is high, but in the absence of design and cost details, ERG is unable to quantitatively assess this. ERG does agree that some significant cost is involved and that it would tend to push the Boardman installed cost toward the upper end of the range cited above (\$207/kW to \$267/kW). Bearing in mind the broad uncertainty band associated with all of the estimates, ERG selected a "round number" cost of \$250/kW as our Boardman Plant SCR installed cost.

4.0 CONCLUSIONS

The following are ERG's conclusions regarding the NO_x control technologies in the PGE Proposal:

- Appropriate NO_x technologies were included in the analysis.
- The control level estimate for NLNB with AOFA is reasonable. PGE and B&V enlisted Fuel Tech to more closely examine the Boardman Plant and confirm SNCR performance. The resulting B&V estimate of 18 percent control is reasonable. SCR units can achieve control to the 0.05 lbs/MMBtu level, but not necessarily meet a 0.05 limit. Most of SCR experience is with ozone-season units that are afforded significant off-season opportunity for maintenance and catalyst cleaning. The impact of year-round operation would have to be considered in selecting a permit limit for Boardman.
- NLNB with AOFA costs are reasonable.
- ERG finds that the B&V's estimated installed cost for SNCR is high by at least 50 percent. ERG's estimate (based on CUECost) is \$14/kW versus the B&V cost of about \$28/kW.

- ERG finds that the contention by PGE and B&V that SCR installed costs have escalated extremely rapidly in recent years is supported by a number of literature sources. For reasons not fully clear, CUECost does not capture this recent surge in installed cost, even when the most recent Chemical Engineering Cost Index is applied.
- ERG's analysis of the 2007 cost for retrofitting SCR at the Boardman Plant is based on literature information and on data provided by PGE and B&V. We find a cost of about \$250/kW versus the PGE and B&V estimate of \$309/kW to be reasonable in view of recent similar installations and literature estimates.
- Future mercury control is appropriately addressed by the proposed fabric filter. Since mercury oxidation across an SCR and subsequent collection in an FGD system is relatively ineffective for PRB coal, mercury control at Boardman will likely entail activated carbon injection (or some other dry sorbent) followed by collection in a fabric filter. The other NO_x technologies considered (NLNB, AOFA, SNCR) will not influence the Boardman baseline mercury emissions or future mercury controls.

5.0 REFERENCES

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Attachment A
Inputs Used for CUECost

CUECost INPUTS			
Description	Units	Input 1	Source
<u>General Plant Technical Inputs</u>			
Location – State	Abbrev.	OR	PGE report
MW Equivalent of Flue Gas to Control System	MW	584	PGE report
Net Plant Heat Rate	Btu/kWhr	9,817	PGE report
Plant Capacity Factor	%	85%	PGE report
Total Air Downstream of Economizer	%	117%	PGE report
Air Heater Leakage	%	11%	PGE report
Air Heater Outlet Gas Temperature	°	297	PGE report
Inlet Air Temperature	°	80	PGE report
Ambient Absolute Pressure	In. of Hg	29.18	PGE report
Pressure After Air Heater	In. of H ₂ O	-13	PGE report
Moisture in Air	lb/lb dry air	0.01362	PGE report
Ash Split:			
Fly Ash	%	80%	PGE report
Bottom Ash	%	20%	PGE report
Seismic Zone	Integer	1	PGE report
Retrofit Factor	Integer	1.6	PGE report
(1.0 = new, 1.3 = medium, 1.6 = difficult)			
Select Coal	Integer	8	PGE report
Is Selected Coal a Powder River Basin Coal?	Yes / No	Yes	PGE report
<u>Economic Inputs</u>			
Cost Basis -Year Dollars	Year	2007	
Service Life (levelization period)	Years	15	
Inflation Rate	%	3%	CUECost default
After Tax Discount Rate (current \$'s)	%	9%	CUECost default
AFDC Rate (current \$'s)	%	11%	CUECost default
First-year Carrying Charge (current \$'s)	%	22%	CUECost default
Levelized Carrying Charge (current \$'s)	%	17%	CUECost default
First-year Carrying Charge (constant \$'s)	%	16%	CUECost default
Levelized Carrying Charge (constant \$'s)	%	12%	CUECost default
Sales Tax	%	6%	CUECost default
Escalation Rates:			
Consumables (O&M)	%	3%	CUECost default
Capital Costs:			
Is Chem. Eng. Cost Index available?	Yes / No	Yes	
If "Yes" input cost basis CE Plant Index.	Integer	525.4	CE Cost Index
If "No" input escalation rate.	%	3%	
Construction Labor Rate	\$/hr	\$35	PGE report
Prime Contractor's Markup	%	3%	PGE report
Operating Labor Rate	\$/hr	\$30	PGE report
Power Cost	Mills/kWh	65.3	DOE website for 2006
Steam Cost	\$/1000 lbs	3.5	PGE report
<u>NO_x Control Inputs</u>			

CUECost INPUTS			
Description	Units	Input 1	Source
<u>Selective Catalytic Reduction (SCR) Inputs</u>			
NH ₃ /NO _x Stoichiometric Ratio	NH ₃ /NO _x	1.05	PGE report
NO _x Reduction Efficiency	Fraction	0.90	
Inlet NO _x	lbs/MMBtu	0.426	PGE report
Space Velocity (Calculated if zero)	1/hr	0	PGE report
Overall Catalyst Life	years	3	PGE report
Ammonia Cost	\$/ton	400	Price for 2007
Catalyst Cost	\$/ft ³	169.9	PGE report
Solid Waste Disposal Cost	\$/ton	10	PGE report
Maintenance (% of installed cost)	%	1.5%	CUECost default
Contingency (% of installed cost)	%	20%	CUECost default
General Facilities (% of installed cost)	%	5%	CUECost default
Engineering Fees (% of installed cost)	%	10%	CUECost default
Number of Reactors	integer	2	PGE report
Number of Air Preheaters	integer	1	PGE report
<u>Selective NonCatalytic Reduction (SNCR) Inputs</u>			
Reagent	1:Urea 2:Ammonia	1	PGE report
Number of Injector Levels	integer	3	PGE report
Number of Injectors	integer	18	PGE report
Number of Lance Levels	integer	0	PGE report
Number of Lances	integer	8	PGE report
Steam or Air Injection for Ammonia	integer	1	PGE report
NO _x Reduction Efficiency	Fraction	0.50	
Inlet NO _x	lbs/MMBtu	0.426	PGE report
NH ₃ /NO _x Stoichiometric Ratio	NH ₃ /NO _x	1.2	PGE report
Urea/NO _x Stoichiometric Ratio	Urea/NO _x	1.2	PGE report
Urea Cost	\$/ton	315	PGE report
Ammonia Cost	\$/ton	450	PGE report
Water Cost	\$/1,000 gal	2	PGE report
Maintenance (% of installed cost)	%	1.5%	CUECost default
Contingency (% of installed cost)	%	20%	CUECost default
General Facilities (% of installed cost)	%	5%	CUECost default
Engineering Fees (% of installed cost)	%	10%	CUECost default
<u>Low NO_x Burner Technology Inputs</u>			
NO _x Reduction Efficiency	fraction	0.35	
Boiler Type	T:T-fired, W:Wall	W	PGE report
Retrofit Difficulty	L:Low, A:Average, H:High	A	
Maintenance Labor (% of installed cost)	%	0.8%	CUECost default
Maintenance Materials (% of installed cost)	%	1.2%	CUECost default

Attachment B
CUECost Outputs

SCR (high-dust) – Preliminary		Case1
Ammonia Injection Rate	lb/hr	949
Space Velocity	1/hr	1,873
Gross Catalyst Volume	ft ³	39,736
SCR Capital Costs		Case1
		
	Cost Basis (Year)	2007
Reactor Housing and Installation	\$	6,933,702
Ammonia Handling and Injection	\$	2,034,420
Flue Gas Handling:Ductwork and Fans	\$	7,222,232
Air Preheater Modifications	\$	1,828,819
Misc. Other Direct Capital Costs	\$	604,355
Equipment Capital Cost Subtotal	\$	\$18,623,527
Instruments & Controls	\$	\$372,471
Taxes	\$	\$1,117,412
Freight	\$	<u>\$931,176</u>
Total Direct Cost		\$21,044,586
Total Direct Cost with Retrofit Factor	\$	\$33,671,337
General Facilities	\$	\$1,683,567
Engineering Fees	\$	\$3,367,134
Contingency	\$	<u>\$6,734,267</u>
Total Plant Cost (TPC)	\$	\$45,456,305
Total Plant Cost (TPC) w/ Prime Contractor's Markup	\$	\$46,819,994
Total Cash Expended (TCE)	\$	\$45,469,545
Allow. for Funds During Constr. (AFDC)	\$	<u>\$4,985,542</u>
Total Plant Investment (TPI)	\$	\$50,455,086
Preproduction Costs	\$	\$1,215,710
Inventory Capital		
Initial Ammonia(60 days)	\$	\$232,401
Initial Catalyst	\$	<u>\$6,751,206</u>
Total Capital Requirement (TCR)	\$	\$58,654,404
	\$/kW	\$100
SCR O&M Costs		Case1
		
	Cost Basis (Year)	2007
Ammonia	\$/yr	1,413,774
Catalyst Replacement	\$/yr	2,250,402
Catalyst Disposal	\$/yr	3,179
Electricity	\$/yr	1,041,331
High-dust SCR Steam	\$/yr	93,969
Operating Labor	\$/yr	134,190
Supervisory labor	\$/yr	20,128
Maintenance	\$/yr	681,845
Total O&M Costs	\$/yr	5,618,690
taxes, insurance, administrative	\$/yr	\$2,346,176
capital recovery	\$/yr	\$6,439,938
Total Annual Cost	\$/yr	\$12,078,756

<i>SNCR - Preliminary</i>		Case1
Number of Wall Injectors	integer	18
Number of Lances	integer	8
Urea Injection Rate	lb/hr	1905
Ammonia Injection Rate	lb/hr	1085
<i>SNCR Capital Costs</i>		Case1
		
	<i>Cost Basis (Year)</i>	<u>2007</u>
Urea Based SNCR Costs		
Urea Storage & Handling	\$	\$485,138
Urea Injection	\$	\$983,103
Controls/Miscellaneous	\$	\$260,286
Air Heater Modifications	\$	\$1,394,942
Ammonia Based SNCR Costs		
Ammonia Storage, Handling, Injection, Controls	\$	\$0
Air Heater Modifications	\$	<u>\$0</u>
<i>Total Direct Cost</i>	\$	\$3,123,469
Total Direct Cost with Retrofit Factor	\$	\$4,997,551
General Facilities	\$	\$249,878
Engineering Fees	\$	\$499,755
Contingency	\$	<u>\$999,510</u>
<i>Total Plant Cost (TPC)</i>	\$	\$6,746,693
<i>Total Plant Cost (TPC) w/ Prime Contractor's Markup</i>	\$	\$6,949,094
<i>Total Cash Expended (TCE)</i>	\$	\$6,748,659
<i>Allow. for Funds During Constr. (AFDC)</i>	\$	<u>\$739,962</u>
<i>Total Plant Investment (TPI)</i>	\$	\$7,488,620
<i>Preproduction Costs</i>	\$	\$386,037
<i>Inventory Capital</i>	\$	\$367,247
Freight		
<i>Total Capital Requirement (TCR)</i>	\$	\$8,241,904
	\$/kW	\$14.1
<i>SNCR O&M Costs</i>		Case1
		
	<i>Cost Basis (Year)</i>	<u>2007</u>
Operating and Supervisory Labor	\$/yr	65,700
Maintenance Labor and Materials	\$/yr	101,200
Reagent	\$/yr	2,234,084
Electricity	\$/yr	8,825
Water	\$/yr	33,954
Steam (for steam atomization)	\$/yr	-
Total O&M Costs	\$/yr	2,443,763
CR		904,917
Total Annual Cost		3,348,680

<i>Low NO_x Burner Technology Capital Costs</i>		Case1
<i>Cost Basis (Year)</i>		<u>2007</u>
Total Capital Requirement with Retrofit (TCR)	\$	\$10,445,451
	\$/kW	\$17.9
<i>Low NO_x Burner Technology O&M Costs</i>		Case1
<i>Cost Basis (Year)</i>		<u>2007</u>
Maintenance Labor	\$/yr	83,564
Maintenance Materials	\$/yr	125,345
Control, Administration, Overhead	\$/yr	25,069
Total O&M Costs	\$/yr	233,978
CR		1,146,854
Total Annual Cost		1,380,833

Attachment C

**Comparison of PGE Proposal Using CUECost and ERG CUECost
Results for SCR**

Cost Category	Subcategory	Cost Item	PGE	CUECost (2007)	Comment
<i>Direct Costs</i>	Purchased Equipment Cost (PEC)	Reactor Housing	\$5,580,000	\$6,933,702	
		Ammonia Handling and Injection	2,589,000	2,034,420	
		Initial Catalyst and Ammonia	4,750,000	6,983,607	
		Flue Gas Handling System	6,500,000	7,222,232	
		Air Preaheater Mod.	2,835,000	1,828,819	
		Electical System Mod.	2,261,000		
		ID Fans	3,658,000		
		Ash Handling System	3,100,000		
		Miscellaneous Direct Capital costs		604,355	
		<i>Total Capital Cost</i>	<i>\$31,273,000</i>	<i>\$25,607,134</i>	
		Instruments and Controls	3,127,300	372,471	PGE used 10% of Capital Cost, CUECost uses 2%
		Freight	1,563,650	931,176	
		Taxes		1,117,412	
		Total PEC	\$35,963,950	\$28,028,193	
	Direct Installation Costs (DIC)	Foundation and Support	\$13,666,301		
		Handling and erection	13,306,662		
		Electrical	8,990,988		
		Piping	2,697,296		
		Insulation	3,596,395		
		Painting	359,640		
Demolition		6,113,872			
Relocation		4,315,674			
Retrofit Cost			\$12,626,751		

Cost Category	Subcategory	Cost Item	PGE	CUECost (2007)	Comment
		Total DIC	\$53,046,826	\$12,626,751	
		Site Preparation	2,000,000		
		Buildings	500,000		
		Total Direct Costs	\$91,510,776	\$40,654,944	
Indirect Costs		Engineering	\$10,981,293	\$3,367,134	
		Owner's Cost	4,575,539		
		Construction Management	9,151,078		
		Start-up and spare parts	2,745,323		
		Performance Test	200,000		
		Contingencies	13,726,616	6,734,267	
		Contractors Markup		1,363,689	
		General Facilities		1,683,567	
		Total Indirect Costs	\$13,148,657	\$13,148,657	
	Allowance for Funds During Construction	17,926,000	4,985,542		
	Boiler Heat Transfer Surface Area Replacement	\$40,000,000			
	Preproduction Costs		\$1,215,710		
	Total Capital Investment Cost	\$190,816,626	\$60,004,853		